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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2009

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).* Yes ☐ No ☐

* The registrant has not yet been phased into the interactive data requirements.

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

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

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

Number of shares outstanding of each of the issuer's classes of common stock, as of April 22, 2009.

Class	Shares Outstanding
No Par Value	92,008,920

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
FSP	FASB Staff Position
GRIP	Gas Reliability Infrastructure Program
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MPSC	Mississippi Public Service Commission
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2009	September 30, 2008
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,873,028	$5,730,156
Less accumulated depreciation and amortization	1,609,836	1,593,297
Net property, plant and equipment	4,263,192	4,136,859
Current assets		
Cash and cash equivalents	482,085	46,717
Accounts receivable, net	531,749	477,151
Gas stored underground	327,288	576,617
Other current assets	137,433	184,619
Total current assets	1,478,555	1,285,104
Goodwill and intangible assets	738,772	739,086
Deferred charges and other assets	205,242	225,650
	$6,685,761	$6,386,699
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2009 — 91,947,614 shares; September 30, 2008 — 90,814,683 shares	$ 460	$ 454
Additional paid-in capital	1,768,307	1,744,384
Retained earnings	480,355	343,601
Accumulated other comprehensive loss	(70,628)	(35,947)
Shareholders' equity	2,178,494	2,052,492
Long-term debt	2,169,141	2,119,792
Total capitalization	4,347,635	4,172,284
Current liabilities		
Accounts payable and accrued liabilities	472,078	395,388
Other current liabilities	413,764	460,372
Short-term debt	—	350,542
Current maturities of long-term debt	400,225	785
Total current liabilities	1,286,067	1,207,087
Deferred income taxes	466,868	441,302
Regulatory cost of removal obligation	313,486	298,645
Deferred credits and other liabilities	271,705	267,381
	$6,685,761	$6,386,699

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,230,420	$1,521,856
Regulated transmission and storage segment	59,234	51,440
Natural gas marketing segment	708,658	1,128,653
Pipeline, storage and other segment	12,272	10,022
Intersegment eliminations	(189,178)	(227,986)
	1,821,406	2,483,985
Purchased gas cost		
Natural gas distribution segment	863,340	1,164,332
Regulated transmission and storage segment	—	—
Natural gas marketing segment	685,114	1,112,321
Pipeline, storage and other segment	1,656	338
Intersegment eliminations	(188,755)	(227,400)
	1,361,355	2,049,591
Gross profit	460,051	434,394
Operating expenses		
Operation and maintenance	121,740	120,053
Depreciation and amortization	53,450	48,790
Taxes, other than income	58,314	54,408
Total operating expenses	233,504	223,251
Operating income	226,547	211,143
Miscellaneous income (expense)	(1,565)	1,467
Interest charges	35,533	33,516
Income before income taxes	189,449	179,094
Income tax expense	60,446	67,560
Net income	$ 129,003	$ 111,534
Basic net income per share	$ 1.42	$ 1.25
Diluted net income per share	$ 1.41	$ 1.24
Cash dividends per share	$ 0.330	$ 0.325
Weighted average shares outstanding:		
Basic	90,895	89,314
Diluted	91,567	89,990

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,286,388	$2,450,033
Regulated transmission and storage segment	113,916	96,486
Natural gas marketing segment	1,496,153	1,969,370
Pipeline, storage and other segment	28,720	16,749
Intersegment eliminations	(387,439)	(391,143)
	3,537,738	4,141,495
Purchased gas cost		
Natural gas distribution segment	1,620,924	1,819,309
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,442,586	1,907,075
Pipeline, storage and other segment	5,559	1,067
Intersegment eliminations	(386,594)	(389,988)
	2,682,475	3,337,463
Gross profit	855,263	804,032
Operating expenses		
Operation and maintenance	256,495	241,242
Depreciation and amortization	106,576	97,303
Taxes, other than income	102,451	95,835
Total operating expenses	465,522	434,380
Operating income	389,741	369,652
Miscellaneous income (expense)	(1,866)	1,374
Interest charges	74,524	70,333
Income before income taxes	313,351	300,693
Income tax expense	108,385	115,356
Net income	$ 204,966	$ 185,337
Basic net income per share	$ 2.26	$ 2.08
Diluted net income per share	$ 2.24	$ 2.06
Cash dividends per share	$ 0.66	$ 0.65
Weighted average shares outstanding:		
Basic	90,637	89,133
Diluted	91,311	89,817

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2009	2008
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 204,966	$ 185,337
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	106,576	97,303
Charged to other accounts	21	67
Deferred income taxes	97,892	72,277
Other	13,634	6,853
Net assets/liabilities from risk management activities	5,810	(22,667)
Net change in operating assets and liabilities	185,723	140,022
Net cash provided by operating activities	614,622	479,192
Cash Flows From Investing Activities		
Capital expenditures	(221,330)	(198,722)
Other, net	(3,925)	(3,132)
Net cash used in investing activities	(225,255)	(201,854)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(353,468)	(150,582)
Net proceeds from debt offering	446,188	—
Settlement of Treasury lock agreement	1,938	—
Repayment of long-term debt	(625)	(2,253)
Cash dividends paid	(60,446)	(58,431)
Issuance of common stock	12,414	12,839
Net cash provided by (used in) financing activities	46,001	(198,427)
Net increase in cash and cash equivalents	435,368	78,911
Cash and cash equivalents at beginning of period	46,717	60,725
Cash and cash equivalents at end of period	$ 482,085	$ 139,636

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2009

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[(1)]
Atmos Energy Kentucky/Mid-States Division	Georgia[(1)], Illinois[(1)], Iowa[(1)], Kentucky, Missouri[(1)], Tennessee, Virginia[(1)]
Atmos Energy Louisiana Division	Louisiana
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 states where we have more limited service areas.

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

Our regulated transmission and storage business consists of the regulated operations of our Atmos Pipeline — Texas Division. 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 to the pipeline industry including parking arrangements, lending and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands.

Our nonregulated businesses operate primarily in the Midwest and Southeast and include our natural gas marketing operations and pipeline, storage and other operations. These businesses are operated through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH), which is wholly owned by the Company and based in Houston, Texas.

Our natural gas marketing operations are conducted through 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 Southeast and Midwest and to our Colorado-Kansas, Kentucky/Mid-States and Louisiana 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 financial instruments.

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is used primarily to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM, but also provides limited third party transportation services.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are asset management plans with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements.

Further, APS owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods. Finally, APS manages our natural gas gathering operations, which were limited in nature as of March 31, 2009.

2. Unaudited Interim Financial Information

In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2009 are not indicative of our results of operations for the full 2009 fiscal year, which ends September 30, 2009.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008, and there were no changes to those policies. However, during the six months ended March 31, 2009, we recognized a non-recurring $8.3 million increase in gross profit associated with a one-time update to our estimate for gas delivered to customers but not yet billed, resulting from base rate changes in several jurisdictions.

During the second quarter of fiscal 2009, we updated the tax rates used to record deferred taxes. The one-time tax benefit resulted in a favorable impact to net income of $11.3 million.

Additionally, during the second quarter of fiscal 2009, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

Effective October 1, 2008, the Company adopted Statement of Financial Accounting Standards (SFAS) 157, *Fair Value Measurements*, the measurement date requirements of SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115,* SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133* and FASB Staff Position (FSP) FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments.* Except for the adoption of these accounting pronouncements, which are further discussed below, there were no significant changes to our accounting policies during the six months ended March 31, 2009.

SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosure on fair value measurements required under other accounting pronouncements but does not change existing

guidance as to whether or not an instrument is carried at fair value. The adoption of this standard did not materially impact our financial position, results of operations or cash flows. The new disclosures required by this standard are presented in Note 4.

Effective October 1, 2008, the Company adopted the measurement date requirements of SFAS 158 using the remeasurement approach. Under this approach, the Company remeasured its projected benefit obligation, fair value of plan assets and its fiscal 2009 net periodic cost. In accordance with the transition rules of SFAS 158, the impact of changing the measurement date from June 30, 2008 to September 30, 2008 decreased retained earnings by $7.8 million, net of tax, decreased the unrecognized actuarial loss by $9.0 million and increased our postretirement liabilities by $3.5 million during the first quarter of fiscal 2009.

SFAS 159 permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of the standard is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis. The fair value option is irrevocable, unless a new election date occurs. The adoption of this standard did not impact our financial position, results of operations or cash flows.

SFAS 161 expands the disclosure requirements for derivative instruments and hedging activities. This statement requires specific disclosures regarding how and why an entity uses derivative instruments; the accounting for derivative instruments and related hedged items; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. Since SFAS 161 only requires additional disclosures concerning derivatives and hedging activities, this standard did not have an impact on our financial position, results of operations or cash flows. The new disclosures required by this standard are presented in Note 3.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. This FSP requires companies to disclose the fair value of financial instruments for which it is practicable to estimate the value and the methods and significant assumptions used to estimate the fair value. The disclosure is required for interim and annual reports. The disclosure requirements of this FSP are presented in Note 4.

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

Significant regulatory assets and liabilities as of March 31, 2009 and September 30, 2008 included the following:

	March 31, 2009	September 30, 2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 89,244	$100,563
Merger and integration costs, net	7,374	7,586
Deferred gas costs	58,660	55,103
Environmental costs	741	980
Rate case costs	9,144	12,885
Deferred franchise fees	597	651
Deferred income taxes, net	343	343
Other	7,846	8,120
	$173,949	$186,231
Regulatory liabilities:		
Deferred gas costs	$ 61,177	$ 76,979
Regulatory cost of removal obligation	329,120	317,273
Other	5,499	5,639
	$395,796	$399,891

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

Comprehensive income

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and six-month periods ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Net income	$129,003	$111,534	$204,966	$185,337
Unrealized holding losses on investments, net of tax benefit of $429 and $1,385 for the three months ended March 31, 2009 and 2008 and of $3,759 and $671 for the six months ended March 31, 2009 and 2008	(862)	(2,262)	(6,295)	(1,097)
Other than temporary impairment of investments, net of tax expense of $790 for the six months ended March 31, 2009	—	—	1,288	—
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $1,353 and $482 for the three months ended March 31, 2009 and 2008 and $1,835 and $964 for the six months ended March 31, 2009 and 2008	1,854	787	2,641	1,574
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $(7,524) and $2,260 for the three months ended March 31, 2009 and 2008 and $(21,341) and $7,197 for the six months ended March 31, 2009 and 2008	(9,771)	3,690	(32,315)	11,743
Comprehensive income	$120,224	$113,749	$170,285	$197,557

Accumulated other comprehensive loss, net of tax, as of March 31, 2009 and September 30, 2008 consisted of the following unrealized gains (losses):

	March 31, 2009	September 30, 2008
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains (losses) on investments	$ (4,097)	$ 910
Treasury lock agreements	(8,463)	(11,104)
Cash flow hedges	(58,068)	(25,753)
	$(70,628)	$(35,947)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. However, our pipeline, storage

and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

In our natural gas distribution segment, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. If the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2008-2009 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we anticipated hedging approximately 29 percent, or 25.5 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with SFAS 71. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

Our natural gas marketing segment, through AEM, 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.

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging 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 instruments at advantageous prices to lock in a gross profit margin. We also seek to 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. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas

inventory will be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 46 months. The effective portion of the unrealized gains and losses arising from the use of cash flow hedges is recorded as a component of accumulated other comprehensive income (AOCI) on the balance sheet. Amounts associated with cash flow hedges recognized in the income statement include (i) the amount of unrealized gain or loss that has been reclassified from AOCI when the hedged volumes are sold and (ii) the amount of ineffectiveness associated with these hedges in the period the ineffectiveness arises.

We use financial instruments, designated as fair value hedges, to hedge the exposure to changes in the fair value of our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments. Therefore, gains and losses arising from these financial instruments should offset the changes in the fair value of the hedged item to the extent the hedging relationship is effective. Ineffectiveness is recognized in the income statement in the period the ineffectiveness arises.

Also, in our natural gas marketing segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. Our risk management committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on March 31, 2009, AEH had net open positions (including existing storage) of less than 0.1 Bcf.

Interest Rate Risk Management Activities

In March 2009, we entered into a Treasury lock agreement to fix the Treasury yield component of the interest cost associated with our $450 million 8.50% senior notes (the Senior Notes Offering), which was completed on March 26, 2009. The Senior Notes Offering is discussed in Note 5. We designated this Treasury lock as a cash flow hedge of an anticipated transaction. This Treasury lock was settled on March 23, 2009 with the receipt of $1.9 million from the counterparty due to an increase in the 10 year Treasury rates between inception of the Treasury lock and settlement. Because the Treasury lock was effective, the net $1.2 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized over the 10 year life of the senior notes.

In prior years, we similarly managed interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts of these Treasury locks will be recognized as a component of interest expense through fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of March 31, 2009, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of March 31, 2009, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other
			Quantity (MMcf)	
Commodity contracts	Fair Value	—	(19,052)	(1,410)
	Cash Flow	—	38,822	(1,905)
	Not designated	7,727	109,450	(688)
		7,727	129,220	(4,003)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of March 31, 2009 and September 30, 2008. As required by SFAS 161, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $79.1 million and $56.6 million of cash held on deposit in margin accounts as of March 31, 2009 and September 30, 2008 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will

not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
March 31, 2009:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 73,163	$ 73,163
Noncurrent commodity contracts	Deferred charges and other assets	—	8,018	8,018
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(116,698)	(116,698)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,712)	(1,712)
Total		—	(37,229)	(37,229)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	676	40,262	40,938
Noncurrent commodity contracts	Deferred charges and other assets	—	5,108	5,108
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(22,535)	(39,098)	(61,633)
Noncurrent commodity contracts	Deferred credits and other liabilities	(4)	(1,689)	(1,693)
Total		(21,863)	4,583	(17,280)
Total Financial Instruments		$(21,863)	$ (32,646)	$ (54,509)

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
September 30, 2008:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$101,191	$101,191
Noncurrent commodity contracts	Deferred charges and other assets	—	4,984	4,984
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(89,397)	(89,397)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(206)	(206)
Total		—	16,572	16,572
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	—	20,010	20,010
Noncurrent commodity contracts	Deferred charges and other assets	—	1,093	1,093
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(58,566)	(20,145)	(78,711)
Noncurrent commodity contracts	Deferred credits and other liabilities	(5,111)	(988)	(6,099)
Total		(63,677)	(30)	(63,707)
Total Financial Instruments		$(63,677)	$ 16,542	$ (47,135)

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our condensed consolidated income statement, by operating segment, as applicable, for the three and six months ended March 31, 2009 and 2008.

Unrealized margins recorded in our natural gas marketing and pipeline, storage and other segments are comprised of various components, including, but not limited to, unrealized gains and losses arising from hedge ineffectiveness. Our hedge ineffectiveness primarily results from differences in the location and timing of the derivative instrument and the hedged item and could materially affect our results of operations for the reported period. For the three months ended March 31, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $4.2 million and $6.5 million. For the six months ended March 31, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $24.6 million and $45.2 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below. Although these unrealized gains and losses are currently recorded in our income statement, they are not necessarily indicative of the economic gross profit we anticipate realizing when the underlying physical and financial transactions are settled.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2009 and 2008 is presented below.

	Three Months Ended March 31, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 19,870	$2,105	$ 21,975
Fair value adjustment for natural gas inventory designated as the hedged item	(18,562)	(437)	(18,999)
Total impact on revenue	$ 1,308	$1,668	$ 2,976
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 2,327	$ —	$ 2,327
Timing ineffectiveness	(1,019)	1,668	649
	$ 1,308	$1,668	$ 2,976

	Three Months Ended March 31, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$(33,448)	$ (735)	$(34,183)
Fair value adjustment for natural gas inventory designated as the hedged item	39,922	1,352	41,274
Total impact on revenue	$ 6,474	$ 617	$ 7,091
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (739)	$ —	$ (739)
Timing ineffectiveness	7,213	617	7,830
	$ 6,474	$ 617	$ 7,091

	Six Months Ended March 31, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 45,553	$ 6,044	$ 51,597
Fair value adjustment for natural gas inventory designated as the hedged item	(30,422)	(1,990)	(32,412)
Total impact on revenue	$ 15,131	$ 4,054	$ 19,185
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 4,279	$ —	$ 4,279
Timing ineffectiveness	10,852	4,054	14,906
	$ 15,131	$ 4,054	$ 19,185

	Six Months Ended March 31, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$(16,221)	$1,387	$(14,834)
Fair value adjustment for natural gas inventory designated as the hedged item	57,523	2,410	59,933
Total impact on revenue	$ 41,302	$3,797	$ 45,099
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 1,217	$ —	$ 1,217
Timing ineffectiveness	40,085	3,797	43,882
	$ 41,302	$3,797	$ 45,099

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot to forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 2009 and 2008 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended March 31, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(48,585)	$16,170	$(32,415)
Gain arising from ineffective portion of commodity contracts	—	1,180	—	1,180
Total impact on revenue	—	(47,405)	16,170	(31,235)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)	—	—	(1,269)
Total Impact from Cash Flow Hedges	$(1,269)	$(47,405)	$16,170	$(32,504)

	Three Months Ended March 31, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(8,040)	$13,492	$ 5,452
Loss arising from ineffective portion of commodity contracts	—	(634)	—	(634)
Total impact on revenue	—	(8,674)	13,492	4,818
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)	—	—	(1,269)
Total Impact from Cash Flow Hedges	$(1,269)	$(8,674)	$13,492	$ 3,549

	Six Months Ended March 31, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(76,829)	$24,139	$(52,690)
Gain arising from ineffective portion of commodity contracts	—	5,372	—	5,372
Total impact on revenue	—	(71,457)	24,139	(47,318)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,538)	—	—	(2,538)
Total Impact from Cash Flow Hedges	$(2,538)	$(71,457)	$24,139	$(49,856)

	Six Months Ended March 31, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(17,294)	$13,916	$(3,378)
Gain arising from ineffective portion of commodity contracts	—	126	—	126
Total impact on revenue	—	(17,168)	13,916	(3,252)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,538)	—	—	(2,538)
Total Impact from Cash Flow Hedges	$(2,538)	$(17,168)	$13,916	$(5,790)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 2009 and 2008. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ 1,221	$ —	$ 1,221	$ —
Forward commodity contracts	(29,544)	7,070	(64,659)	9,649
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	633	787	1,420	1,574
Forward commodity contracts	19,773	(3,380)	32,344	2,094
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ (7,917)	$ 4,477	$(29,674)	$13,317

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2009:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(2,426)	$(54,233)	$(56,659)
Thereafter	(6,037)	(3,835)	(9,872)
Total[(1)]	$(8,463)	$(58,068)	$(66,531)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three and six months ended March 31, 2009 and 2008 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact to our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Natural gas marketing commodity contracts	$10,593	$(14,120)	$6,761	$(13,794)
Pipeline, storage and other commodity contracts	183	(245)	100	(889)
Total impact on revenue	$10,776	$(14,365)	$6,861	$(14,683)

4. Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP) and expands disclosures about fair value measurements. This Statement does not require any new fair value measurements; rather it provides guidance on how to perform fair value measurements as required or permitted under previous accounting pronouncements.

We prospectively adopted the provisions of SFAS 157 on October 1, 2008 for most of the financial assets and liabilities recorded on our balance sheet at fair value. Adoption of this statement for these assets and liabilities did not have a material impact on our financial position, results of operations or cash flows.

In February 2008, the FASB issued FSP FAS 157-2, *Effective Date of FASB Statement No. 157,* which provided a one-year deferral of SFAS 157 for nonrecurring fair value measurements associated with our nonfinancial assets and liabilities. Under this partial deferral, SFAS 157 will not be effective until October 1, 2009 for fair value measurements for the following:

- Asset retirement obligations
- Most nonfinancial assets and liabilities that may be acquired in a business combination
- Impairment analyses performed for nonfinancial assets

We believe the adoption of SFAS 157 for the reporting of these nonfinancial assets and liabilities will not have a material impact on our financial position, results of operations or cash flows.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*, which clarified the application of SFAS 157 in inactive markets. This FSP did not impact our financial position, results of operations or cash flows.

SFAS 157 also applies to the valuation of our pension and post-retirement plan assets. The adoption of this standard did not affect these valuations because SFAS 157 specifically excluded pension and post-

retirement assets from its prescribed disclosure provisions. Accordingly, these plan assets are not included in the tabular disclosures below. However, in December 2008, the FASB issued FSP FAS 132(R)-1 — *Employers' Disclosures about Postretirement Benefit Plan Assets*, which will, among other things, require disclosure about fair value measurements similar to those required by SFAS 157. This FSP will impact our annual disclosure requirements beginning in fiscal 2010.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. This FSP requires companies to disclose the fair value of financial instruments for which it is practicable to estimate the value and the methods and significant assumptions used to estimate the fair value. We have adopted the disclosure requirements of this FSP, which are presented below.

Determining Fair Value

SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under SFAS 157. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. A continued tightening of the credit markets could cause more of our counterparties to fail to perform. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities.

Level 2 — Pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-

exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable.

Level 3 — Generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. Currently, we have no assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009. As required under SFAS 157, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[1]	March 31, 2009
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 676	$ —	$ —	$ 676
Natural gas marketing segment	45,770	80,564	—	(75,558)	50,776
Total financial instruments	45,770	81,240	—	(75,558)	51,452
Hedged portion of gas stored underground					
Natural gas marketing segment	62,912	—	—	—	62,912
Pipeline, storage and other segment[2]	3,656	—	—	—	3,656
Total gas stored underground	66,568	—	—	—	66,568
Available-for-sale securities	26,605	—	—	—	26,605
Total assets	$138,943	$81,240	$ —	$ (75,558)	$144,625
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$22,539	$ —	$ —	$ 22,539
Natural gas marketing segment	117,413	41,567	—	(154,656)	4,324
Total liabilities	$117,413	$64,106	$ —	$(154,656)	$ 26,863

[1] This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and FSP FIN 39-1. In addition, as of March 31, 2009, we had $79.1 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $71.6 million was used to offset financial instruments in a liability position. The remaining $7.5 million has been reflected as a financial instrument asset.

[2] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Other Fair Value Measures

In addition to the financial instruments above, we have several nonfinancial assets and liabilities subject to fair value measures. These assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable, debt, asset retirement obligations and pension and post-retirement plan assets. As noted above, fair value disclosures for asset retirement obligations and pension and post-retirement plan assets are not currently effective for us. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities. The fair value of our debt is determined using a discounted cash flow analysis based upon borrowing rates currently available to us, the remaining average maturities and our credit rating. The following table presents the carrying value and fair value of our debt as of March 31, 2009:

	March 31, 2009 (In thousands)
Carrying Amount	$2,572,987
Fair Value	$2,166,454

The fair value as of March 31, 2009 was calculated utilizing discount rates ranging from 6.6 percent to 9.6 percent, remaining average maturities ranging from one to 26 years, and a credit adjustment of 6.0 percent.

5. Debt

Long-term debt

Long-term debt at March 31, 2009 and September 30, 2008 consisted of the following:

	March 31, 2009	September 30, 2008
	(In thousands)	
Unsecured 4.00% Senior Notes, due April 2009	$ 400,000	$ 400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	—
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
Other term notes due in installments through 2013	684	1,309
Total long-term debt	2,572,987	2,123,612
Less:		
Original issue discount on unsecured senior notes and debentures	(3,621)	(3,035)
Current maturities	(400,225)	(785)
	$2,169,141	$2,119,792

On March 26, 2009, we closed our Senior Notes Offering. The effective interest rate on these notes is 8.69 percent, after giving effect to the settlement of the $450 million treasury lock discussed in Note 3. Most of the net proceeds of approximately $446 million were used to redeem our $400 million 4.00% unsecured senior notes, which, on March 30, 2009, were called for redemption on April 30, 2009, prior to their October 2009 maturity. In connection with the repayment of the $400 million 4.00% unsecured senior notes, we paid a $6.6 million call premium in accordance with the terms of the senior notes and accrued interest of approximately $0.6 million. The remaining net proceeds will be used for general corporate purposes.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. At March 31, 2009, there was no short-term debt outstanding. At September 30, 2008, there was $350.5 million of short-term debt outstanding, comprised of $330.5 million outstanding under our bank credit facilities and $20.0 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed primarily through a $566.7 million commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $800 million of working capital funding. The first facility is a five-year unsecured facility, expiring December 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At the time this credit facility was established, borrowings under this facility were limited to $600 million. However, in September 2008, the limit on borrowings was effectively reduced to $566.7 million after one lender with a 5.55% share of the commitments ceased funding under the facility. On March 30, 2009, the credit facility was amended to reflect this reduction. At March 31, 2009, there were no borrowings under this facility and $566.7 million was available.

The second facility is a $212.5 million unsecured 364-day facility expiring October 2009, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.25 percent to 2.50 percent, based on the Company's credit ratings. At March 31, 2009, there were no borrowings outstanding under this facility.

The third facility was an $18 million unsecured facility that bore interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At March 31, 2009, there were no borrowings outstanding under this facility. This facility expired on March 31, 2009 and was replaced with a $25 million unsecured facility effective April 1, 2009 that bears interest at a daily negotiated rate.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2009, our total-debt-to-

total-capitalization ratio, as defined, was 56 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations had a $200 million intercompany revolving credit facility with AEH. Through December 31, 2008, this facility bore interest at the one-month LIBOR rate plus 0.20 percent. In January 2009, this facility was replaced with a new $200 million 364 day-facility that bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved the new facility through December 31, 2009. There were no borrowings outstanding under this facility at March 31, 2009.

Nonregulated Operations

On December 30, 2008, AEM and the participating banks amended and restated AEM's former uncommitted credit facility, primarily to convert the $580 million uncommitted demand credit facility to a 364-day $375 million committed revolving credit facility and extend it to December 29, 2009.

The amended facility also provides the ability for AEM to increase the borrowing base up to a maximum of $450 million through an accordion feature, subject to the approval of the participating banks; adds a swing line loan feature; adjusts the interest rate on borrowings as discussed below and increases the fees paid to reflect the facility's conversion to a committed facility and current credit market conditions. The swing line loan feature allows AEM to borrow, on a same day basis, an amount ranging from $17 million to $27 million based on the terms of an election within the agreement. Effective April 1, 2009, the borrowing base was increased to $450 million as a result of the exercise of the accordion feature in the facility.

AEM uses this facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest federal funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a one-month interest period) as in effect from time to time; and (d) the "cost of funds" rate based on an average of interest rates reported by one or more of the lenders to the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; and (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 2.250 percent to 2.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At March 31, 2009, there were no borrowings outstanding under this credit facility. However, at March 31, 2009, AEM letters of credit totaling $48.4 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 $201.0 million at March 31, 2009.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At March 31, 2009, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.83 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $75 million to $112.5 million. As defined in the financial

covenants, at March 31, 2009, AEM's net working capital was $251.5 million and its tangible net worth was $271.3 million.

To supplement borrowings under this facility, through December 31, 2008, AEM had a $200 million intercompany demand credit facility with AEH, which bore interest at the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Amounts outstanding under this facility are subordinated to AEM's committed credit facility. This facility was replaced with another $200 million 364-day facility in January 2009 with no material changes to its terms except for the rate of interest, which is the greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. A total of $60.0 million was outstanding under this facility at March 31, 2009.

Finally, through December 31, 2008, AEH had a $200 million intercompany demand credit facility with AEC, which bore interest at the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. This facility was replaced with another $200 million 364-day facility in January 2009 with no material changes to its terms except for the rate of interest, which is the greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved the new facility through December 31, 2009. There were no borrowings outstanding under this facility at March 31, 2009.

Shelf Registration

On March 23, 2009, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $450 million of capacity carried over from our prior shelf registration statement filed with the SEC in December 2006.

As of March 31, 2009, we had $450 million of availability remaining under the registration statement after completing our Senior Notes Offering. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $300 million of equity securities and $150 million of subordinated debt securities.

Debt Covenants

In addition to the financial covenants described above, our debt instruments contain various covenants that are usual and customary for debt instruments of these types.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of March 31, 2009. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

Basic and diluted earnings per share for the three and six months ended March 31, 2009 and 2008 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands, except per share amounts)			
Net income	$129,003	$111,534	$204,966	$185,337
Denominator for basic income per share — weighted average common shares	90,895	89,314	90,637	89,133
Effect of dilutive securities:				
Restricted and other shares	639	583	639	585
Stock options	33	93	35	99
Denominator for diluted income per share — weighted average common shares	91,567	89,990	91,311	89,817
Income per share — basic	$ 1.42	$ 1.25	$ 2.26	$ 2.08
Income per share — diluted	$ 1.41	$ 1.24	$ 2.24	$ 2.06

There were approximately 260,000 out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2009. There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2008 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and six months ended March 31, 2009 and 2008 are presented in the following table. All of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,703	$ 3,878	$2,946	$3,341
Interest cost	7,554	6,736	3,520	2,912
Expected return on assets	(6,238)	(6,311)	(573)	(715)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(183)	(171)	—	—
Amortization of actuarial loss	955	1,926	—	—
Net periodic pension cost	$ 5,791	$ 6,058	$6,271	$5,916

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 7,406	$ 7,756	$ 5,892	$ 6,682
Interest cost	15,108	13,472	7,040	5,824
Expected return on assets	(12,476)	(12,621)	(1,146)	(1,430)
Amortization of transition asset	—	—	756	756
Amortization of prior service cost	(366)	(342)	—	—
Amortization of actuarial loss	1,910	3,852	—	—
Net periodic pension cost	$ 11,582	$ 12,117	$12,542	$11,832

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2009 and 2008 are as follows:

	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
Discount rate	7.57%	6.30%	7.57%	6.30%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2009. Based upon this valuation, we expect we will be required to contribute less than $25 million to our pension plans by September 15, 2009.

We contributed $5.2 million to our other post-retirement benefit plans during the six months ended March 31, 2009. We expect to contribute a total of approximately $10 million to these plans during fiscal 2009.

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 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2009. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At March 31, 2009, AEM was committed to purchase 97.6 Bcf within one year, 32.5 Bcf within one to three years and 1.0 Bcf after three years under indexed contracts. AEM is committed to purchase 1.3 Bcf within one year under fixed price contracts with prices ranging from $2.59 to $7.68 per Mcf. Purchases under these contracts totaled $431.5 million and $860.3 million for the three months ended March 31, 2009 and 2008 and $959.0 million and $1,432.3 million for the six months ended March 31, 2009 and 2008.

Our natural gas distribution divisions, except for our 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 and fixed prices. The estimated commitments under these contracts as of March 31, 2009 are as follows (in thousands):

2009	$ 40,033
2010	53,425
2011	5,245
2012	6,769
2013	7,453
Thereafter	2,571
	$115,496

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

After responding to two sets of data requests received from the Commission, the Commission agreed to allow us to conduct our own internal investigation into compliance with the Commission's rules. During the second quarter, we completed our internal investigation and submitted the results to the Commission. During our investigation, we identified certain transactions that could possibly be considered non-compliant, and we continue to fully cooperate with the Commission as we work to resolve this matter. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

As of March 31, 2009, rate cases were in progress in our City of Dallas and Virginia service areas and annual rate filing mechanisms were in progress in our Mid-Tex, West Texas, Louisiana and Atmos Pipeline — Texas divisions. These regulatory proceedings are discussed in further detail in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. During the six months ended March 31, 2009, there were no material changes in our concentration of credit risk.

10. Segment Information

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

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local distribution companies and industrial customers primarily in the Midwest and Southeast. Additionally, we provide natural gas transportation and storage services to certain of our natural gas distribution operations and to third parties.

We operate the Company through the following four segments:

- The *natural gas distribution segment,* which includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment,* which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division.
- The *natural gas marketing segment,* which includes a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment,* which includes our nonregulated natural gas transmission and storage services.

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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2008. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six month periods ended March 31, 2009 and 2008 by segment are presented in the following tables:

	Three Months Ended March 31, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,230,196	$32,097	$549,136	$ 9,977	$ —	$1,821,406
Intersegment revenues	224	27,137	159,522	2,295	(189,178)	—
	1,230,420	59,234	708,658	12,272	(189,178)	1,821,406
Purchased gas cost	863,340	—	685,114	1,656	(188,755)	1,361,355
Gross profit	367,080	59,234	23,544	10,616	(423)	460,051
Operating expenses						
Operation and maintenance	90,710	17,327	12,323	1,889	(509)	121,740
Depreciation and amortization	47,541	5,006	396	507	—	53,450
Taxes, other than income	55,101	2,572	446	195	—	58,314
Total operating expenses	193,352	24,905	13,165	2,591	(509)	233,504
Operating income	173,728	34,329	10,379	8,025	86	226,547
Miscellaneous income (expense)	835	283	118	2,060	(4,861)	(1,565)
Interest charges	28,821	7,349	3,461	677	(4,775)	35,533
Income before income taxes	145,742	27,263	7,036	9,408	—	189,449
Income tax expense	44,166	7,798	3,688	4,794	—	60,446
Net income	$ 101,576	$19,465	$ 3,348	$ 4,614	$ —	$ 129,003
Capital expenditures	$ 84,618	$28,303	$ 88	$ 954	$ —	$ 113,963

	Three Months Ended March 31, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,521,636	$22,830	$ 931,990	$ 7,529	$ —	$2,483,985
Intersegment revenues	220	28,610	196,663	2,493	(227,986)	—
	1,521,856	51,440	1,128,653	10,022	(227,986)	2,483,985
Purchased gas cost	1,164,332	—	1,112,321	338	(227,400)	2,049,591
Gross profit	357,524	51,440	16,332	9,684	(586)	434,394
Operating expenses						
Operation and maintenance	98,578	15,086	5,525	1,536	(672)	120,053
Depreciation and amortization	43,130	4,907	374	379	—	48,790
Taxes, other than income	52,304	1,385	407	312	—	54,408
Total operating expenses	194,012	21,378	6,306	2,227	(672)	223,251
Operating income	163,512	30,062	10,026	7,457	86	211,143
Miscellaneous income	3,670	209	602	1,942	(4,956)	1,467
Interest charges	29,084	6,776	2,002	524	(4,870)	33,516
Income before income taxes	138,098	23,495	8,626	8,875	—	179,094
Income tax expense	52,442	8,271	3,347	3,500	—	67,560
Net income	$ 85,656	$15,224	$ 5,279	$ 5,375	$ —	$ 111,534
Capital expenditures	$ 89,671	$13,700	$ 38	$ 1,158	$ —	$ 104,567

	Six Months Ended March 31, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,285,968	$ 62,319	$1,165,980	$23,471	$ —	$3,537,738
Intersegment revenues	420	51,597	330,173	5,249	(387,439)	—
	2,286,388	113,916	1,496,153	28,720	(387,439)	3,537,738
Purchased gas cost	1,620,924	—	1,442,586	5,559	(386,594)	2,682,475
Gross profit	665,464	113,916	53,567	23,161	(845)	855,263
Operating expenses						
Operation and maintenance	188,704	44,896	20,839	3,073	(1,017)	256,495
Depreciation and amortization	94,680	9,961	797	1,138	—	106,576
Taxes, other than income	95,847	5,360	1,039	205	—	102,451
Total operating expenses	379,231	60,217	22,675	4,416	(1,017)	465,522
Operating income	286,233	53,699	30,892	18,745	172	389,741
Miscellaneous income (expense)	3,956	1,098	419	4,221	(11,560)	(1,866)
Interest charges	61,708	15,428	7,363	1,413	(11,388)	74,524
Income before income taxes	228,481	39,369	23,948	21,553	—	313,351
Income tax expense	76,772	12,243	10,025	9,345	—	108,385
Net income	$ 151,709	$ 27,126	$ 13,923	$12,208	$ —	$ 204,966
Capital expenditures	$ 173,621	$ 33,363	$ 117	$14,229	$ —	$ 221,330

	Six Months Ended March 31, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,449,665	$45,267	$1,634,712	$11,851	$ —	$4,141,495
Intersegment revenues	368	51,219	334,658	4,898	(391,143)	—
	2,450,033	96,486	1,969,370	16,749	(391,143)	4,141,495
Purchased gas cost	1,819,309	—	1,907,075	1,067	(389,988)	3,337,463
Gross profit	630,724	96,486	62,295	15,682	(1,155)	804,032
Operating expenses						
Operation and maintenance	195,825	30,518	13,402	2,824	(1,327)	241,242
Depreciation and amortization	85,962	9,823	761	757	—	97,303
Taxes, other than income	87,922	3,829	3,407	677	—	95,835
Total operating expenses	369,709	44,170	17,570	4,258	(1,327)	434,380
Operating income	261,015	52,316	44,725	11,424	172	369,652
Miscellaneous income	4,146	383	1,398	3,970	(8,523)	1,374
Interest charges	60,298	13,847	3,316	1,223	(8,351)	70,333
Income before income taxes	204,863	38,852	42,807	14,171	—	300,693
Income tax expense	79,043	13,781	16,928	5,604	—	115,356
Net income	$ 125,820	$25,071	$ 25,879	$ 8,567	$ —	$ 185,337
Capital expenditures	$ 173,984	$22,082	$ 69	$ 2,587	$ —	$ 198,722

Balance sheet information at March 31, 2009 and September 30, 2008 by segment is presented in the following tables:

	March 31, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,577,546	$608,118	$ 7,312	$ 70,216	$ —	$4,263,192
Investment in subsidiaries	484,117	—	(2,096)	—	(482,021)	—
Current assets						
Cash and cash equivalents	379,391	—	86,143	16,551	—	482,085
Assets from risk management activities	676	—	42,266	2,394	(3,623)	41,713
Other current assets	671,993	16,614	265,457	77,428	(76,735)	954,757
Intercompany receivables	504,887	—	—	147,783	(652,670)	—
Total current assets	1,556,947	16,614	393,866	244,156	(733,028)	1,478,555
Intangible assets	—	—	1,774	—	—	1,774
Goodwill	569,920	132,367	24,282	10,429	—	736,998
Noncurrent assets from risk management activities	—	—	9,739	—	—	9,739
Deferred charges and other assets	166,610	7,924	873	20,096	—	195,503
	$6,355,140	$765,023	$435,750	$344,897	$(1,215,049)	$6,685,761
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,178,494	$157,270	$ 75,451	$251,396	$ (484,117)	$2,178,494
Long-term debt	2,168,683	—	—	458	—	2,169,141
Total capitalization	4,347,177	157,270	75,451	251,854	(484,117)	4,347,635
Current liabilities						
Current maturities of long-term debt	400,000	—	—	225	—	400,225
Short-term debt	—	—	60,000	—	(60,000)	—
Liabilities from risk management activities	22,535	—	6,734	1,200	(3,623)	26,846
Other current liabilities	586,656	6,850	203,044	76,973	(14,527)	858,996
Intercompany payables	—	525,249	127,421	—	(652,670)	—
Total current liabilities	1,009,191	532,099	397,199	78,398	(730,820)	1,286,067
Deferred income taxes	422,381	71,643	(37,586)	10,542	(112)	466,868
Noncurrent liabilities from risk management activities	4	—	13	—	—	17
Regulatory cost of removal obligation	313,486	—	—	—	—	313,486
Deferred credits and other liabilities	262,901	4,011	673	4,103	—	271,688
	$6,355,140	$765,023	$435,750	$344,897	$(1,215,049)	$6,685,761

	September 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,483,556	$585,160	$ 7,520	$ 60,623	$ —	$4,136,859
Investment in subsidiaries	463,158	—	(2,096)	—	(461,062)	—
Current assets						
Cash and cash equivalents	30,878	—	9,120	6,719	—	46,717
Assets from risk management activities	—	—	69,008	20,239	(20,956)	68,291
Other current assets	774,933	18,396	411,648	56,791	(91,672)	1,170,096
Intercompany receivables	578,833	—	—	135,795	(714,628)	—
Total current assets	1,384,644	18,396	489,776	219,544	(827,256)	1,285,104
Intangible assets	—	—	2,088	—	—	2,088
Goodwill	569,920	132,367	24,282	10,429	—	736,998
Noncurrent assets from risk management activities	—	—	5,473	—	—	5,473
Deferred charges and other assets	195,985	11,212	1,182	11,798	—	220,177
	$6,097,263	$747,135	$528,225	$302,394	$(1,288,318)	$6,386,699
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,052,492	$130,144	$114,559	$218,455	$ (463,158)	$2,052,492
Long-term debt	2,119,267	—	—	525	—	2,119,792
Total capitalization	4,171,759	130,144	114,559	218,980	(463,158)	4,172,284
Current liabilities						
Current maturities of long-term debt	—	—	—	785	—	785
Short-term debt	385,592	—	6,500	—	(41,550)	350,542
Liabilities from risk management activities	58,566	—	20,688	616	(20,956)	58,914
Other current liabilities	538,777	7,053	236,217	62,796	(47,997)	796,846
Intercompany payables	—	543,384	171,244	—	(714,628)	—
Total current liabilities	982,935	550,437	434,649	64,197	(825,131)	1,207,087
Deferred income taxes	384,860	62,720	(21,936)	15,687	(29)	441,302
Noncurrent liabilities from risk management activities	5,111	—	258	—	—	5,369
Regulatory cost of removal obligation	298,645	—	—	—	—	298,645
Deferred credits and other liabilities	253,953	3,834	695	3,530	—	262,012
	$6,097,263	$747,135	$528,225	$302,394	$(1,288,318)	$6,386,699

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of March 31, 2009, the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2009 and 2008, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2009 and 2008. 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, 2008, 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 18, 2008, 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, 2008, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
April 30, 2009

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, 2008.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties, which are discussed in more detail in our Annual Report on Form 10-K for the year ended September 30, 2008, include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of recent economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events; and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

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

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties.

We operate the Company through the following four segments:

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

- the *regulated transmission and storage segment,* which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment,* which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment,* which is comprised of our nonregulated natural gas gathering, transmission and storage services.

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 fiscal year ended September 30, 2008 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 quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the six months ended March 31, 2009.

RESULTS OF OPERATIONS

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands, except per share data)			
Operating revenues	$1,821,406	$2,483,985	$3,537,738	$4,141,495
Gross profit	460,051	434,394	855,263	804,032
Operating expenses	233,504	223,251	465,522	434,380
Operating income	226,547	211,143	389,741	369,652
Miscellaneous income (expense)	(1,565)	1,467	(1,866)	1,374
Interest charges	35,533	33,516	74,524	70,333
Income before income taxes	189,449	179,094	313,351	300,693
Income tax expense	60,446	67,560	108,385	115,356
Net income	$ 129,003	$ 111,534	$ 204,966	$ 185,337
Diluted net income per share	$ 1.41	$ 1.24	$ 2.24	$ 2.06

Our consolidated net income during the three and six months ended March 31, 2009 and 2008 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands)		
Natural gas distribution segment	$101,576	$ 85,656	$15,920
Regulated transmission and storage segment	19,465	15,224	4,241
Natural gas marketing segment	3,348	5,279	(1,931)
Pipeline, storage and other segment	4,614	5,375	(761)
Net income	$129,003	$111,534	$17,469

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands)		
Natural gas distribution segment	$151,709	$125,820	$ 25,889
Regulated transmission and storage segment	27,126	25,071	2,055
Natural gas marketing segment	13,923	25,879	(11,956)
Pipeline, storage and other segment	12,208	8,567	3,641
Net income	$204,966	$185,337	$ 19,629

The following tables segregate our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$121,041	$100,880	$20,161
Nonregulated operations	7,962	10,654	(2,692)
Consolidated net income	$129,003	$111,534	$17,469
Diluted EPS from regulated operations	$ 1.32	$ 1.12	$ 0.20
Diluted EPS from nonregulated operations	0.09	0.12	(0.03)
Consolidated diluted EPS	$ 1.41	$ 1.24	$ 0.17

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$178,835	$150,891	$27,944
Nonregulated operations	26,131	34,446	(8,315)
Consolidated net income	$204,966	$185,337	$19,629
Diluted EPS from regulated operations	$ 1.96	$ 1.68	$ 0.28
Diluted EPS from nonregulated operations	0.28	0.38	(0.10)
Consolidated diluted EPS	$ 2.24	$ 2.06	$ 0.18

The following summarizes the results of our operations and other significant events for the six months ended March 31, 2009:

- Regulated operations generated 87 percent of our net income during the six months ended March 31, 2009 compared to 81 percent during the six months ended March 31, 2008. The $27.9 million increase in our regulated operations net income primarily reflects favorable ratemaking activity coupled with a one-time tax benefit discussed below.
- Nonregulated operations contributed 13 percent of net income during the six months ended March 31, 2009 compared to 19 percent during the six months ended March 31, 2008. The $8.3 million decrease in our nonregulated operations net income primarily reflects a decrease in unrealized margins and an increase in operating expenses partially offset by favorable asset optimization margins.
- For the six months ended March 31, 2009, we generated $614.6 million in operating cash flow compared with $479.2 million for the six months ended March 31, 2008, primarily reflecting the favorable impact on our working capital due to the decline in natural gas prices in the current year compared to the prior-year period and the favorable timing of the recovery of gas costs.
- On March 23, 2009, we filed a $900 million shelf registration statement with the Securities and Exchange Commission (SEC) that replaced our previously existing shelf registration statement. On March 26, 2009, we completed an offering of $450 million unsecured 8.50% senior notes and received net proceeds of approximately $446 million. Most of the net proceeds received were used to repay our $400 million unsecured 4.00% senior notes, which were called on March 30, 2009 for redemption on April 30, 2009.
- Quarter-to-date and year-to-date results were favorably impacted by a one-time tax benefit of $11.3 million, or $0.12 per diluted share. The benefit arose during the quarter when we updated the tax rates used to record our deferred taxes. This benefit increased natural gas distribution net income by $10.5 million and regulated transmission and storage income by $1.7 million. However, net income for the natural gas marketing and pipeline, storage and other segments' net income were reduced by $0.3 million and $0.6 million.

Three Months Ended March 31, 2009 compared with Three Months Ended March 31, 2008

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

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

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Prior to January 1, 2009, timing differences exist between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. The effect of these timing differences could be significant in periods of volatile gas prices, particularly in our Mid-Tex Division. These timing differences may favorably or unfavorably affect net income; however, these amounts should offset over time with no permanent impact on net income. Beginning January 1, 2009, changes in our franchise fee agreements in our Mid-Tex Division became effective which should significantly reduce the impact of this timing difference on a prospective basis. However, this timing difference still occurs for gross receipts taxes.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2009 and 2008 are presented below.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$367,080	$357,524	$ 9,556
Operating expenses	193,352	194,012	(660)
Operating income	173,728	163,512	10,216
Miscellaneous income	835	3,670	(2,835)
Interest charges	28,821	29,084	(263)
Income before income taxes	145,742	138,098	7,644
Income tax expense	44,166	52,442	(8,276)
Net income	$101,576	$ 85,656	$ 15,920
Consolidated natural gas distribution sales volumes — MMcf	121,560	135,568	(14,008)
Consolidated natural gas distribution transportation volumes — MMcf	35,061	39,730	(4,669)
Total consolidated natural gas distribution throughput — MMcf	156,621	175,298	(18,677)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.48	$ 0.44	$ 0.04
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 7.10	$ 8.59	$ (1.49)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the three months ended March 31, 2009 and 2008. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2009	2008	Change
		(In thousands)	
Mid-Tex	$ 80,374	$ 72,479	$ 7,895
Kentucky/Mid-States	27,404	29,875	(2,471)
Louisiana	19,782	19,236	546
West Texas	14,806	8,919	5,887
Mississippi	16,771	16,514	257
Colorado-Kansas	13,623	15,536	(1,913)
Other	968	953	15
Total	$173,728	$163,512	$10,216

The $9.6 million increase in natural gas distribution gross profit primarily reflects a net $21.9 million increase in rates. The net increase in rates was attributable primarily to the Mid-Tex Division, which increased $16.5 million as a result of the implementation of its 2008 Rate Review Mechanism (RRM) filing with all incorporated cities in the division other than the City of Dallas (the Settled Cities) and rate adjustments for customers in the City of Dallas. The current year period also reflects a $5.4 million increase in rate adjustments primarily in Georgia, Louisiana and West Texas. The increase also reflects the reversal of a $7.0 million accrual for estimated unrecoverable gas costs recorded in a prior year. These increases in gross profit were partially offset by a $13.5 million decrease as a result of an 11 percent decrease in distribution throughput, primarily associated with lower residential and commercial consumption and warmer weather in our Colorado service area, which does not have weather-normalized rates.

Partially offsetting these increases was a decrease of approximately $8.9 million in revenue-related taxes primarily due to lower revenues, on which the tax is calculated, in the current-year quarter compared to the prior-year quarter. This decrease was partially offset by a $0.8 million quarter-over-quarter decrease in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulting in an $8.1 million decrease in operating income when compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, decreased $0.7 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $6.9 million, primarily due to lower legal, fuel and other administrative costs.

Depreciation and amortization expense increased $4.4 million for the second quarter of fiscal 2009 compared with second quarter of fiscal 2008. The increase primarily was attributable to additional assets placed in service during the current-year period.

Results for the quarter include the aforementioned $10.5 million tax benefit, which more than offset the decrease attributable to the absence in the current-year quarter of a $1.2 million gain on the sale of irrigation assets in our West Texas Division in the prior-year quarter.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the six months ended March 31, 2009 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's final ruling.

Annual Rate Filing Mechanisms

In March 2009, the Mid-Tex Division filed its second RRM with the Settled Cities. The filing requested an increase in operating income of $9.7 million for the Settled Cities. Representatives of the Settled Cities are currently reviewing the filing and a final determination is expected in July 2009. Beginning in November 2008, rates were implemented from our first RRM filing with the Settled Cities, which resulted in an increase in operating income on a system-wide basis of approximately $27.3 million. The impact to the Mid-Tex Division for the Settled Cities was approximately $21.8 million.

In April 2009, the West Texas Division filed its second RRM with the West Texas Cities. The filing requested an increase in operating income of $11.1 million. Representatives of the West Texas Cities are currently reviewing the filing and a final determination is expected in August 2009. Beginning in November 2008, rates were implemented from our first RRM with the West Texas Cities, which resulted in an increase in operating income of $4.5 million, of which $3.9 million is being collected over a 9½ month period.

In April 2009, the City of Lubbock approved an RRM tariff similar to the RRM tariff utilized by the West Texas Cities. The West Texas Division filed its first RRM with the City of Lubbock on April 15, 2009. The filing requested an increase in operating income of $3.5 million. The City of Lubbock is currently reviewing the filing and a final determination is expected in October 2009.

In December 2008, the Louisiana Division filed its TransLa annual rate stabilization clause with the Louisiana Public Service Commission (LPSC) for the test year ended September 30, 2008. The filing resulted in an increase in operating income of $0.6 million and was implemented in April 2009.

In April 2009, the Louisiana Division filed its LGS annual rate stabilization clause with the LPSC requesting an increase in operating income of $3.9 million. The filing was for the test year ended December 31, 2008. We anticipate final resolution of this proceeding by June 2009.

In September 2008, we filed our Mississippi stable rate filing with the Mississippi Public Service Commission (MPSC) requesting an increase of $3.5 million. In January 2009, we withdrew this request after we were unable to reach a mutually agreeable settlement with the MPSC.

GRIP Filings

In May 2008, the Mid-Tex Division made a GRIP filing seeking a $10.3 million increase on a system-wide basis. However, this filing was only applicable to the City of Dallas and the Mid-Tex environs and sought a $1.8 million increase for customers in those service areas. Rates were approved for this filing in December 2008 and were implemented in January 2009. However, in April 2009, the City of Dallas challenged the legality of the implementation of the GRIP rates, which the Company is contesting in the District Courts of Dallas and Travis Counties.

In March 2009, the Mid-Tex Division made a GRIP filing seeking an $18.7 million increase on a system-wide basis. However, this filing is applicable to the City of Dallas only and seeks a $2.7 million increase for customers in the City of Dallas. The City of Dallas has until July 10, 2009 to either accept or object to the filing. If this filing is accepted, the rates will go into effect until such time that they are superseded by the statement of intent filed with the City of Dallas discussed below.

Rate Case Filings

In October 2008, our Kentucky/Mid-States Division filed a rate case with the Tennessee Regulatory Authority seeking an increase in operating income of $6.3 million. In January 2009, the Consumer Advocate and Protection Division recommended a decrease in rates of $3.7 million. In March 2009, a unanimous stipulation was filed and approved in the case. The parties agreed to an increase in operating income of $2.5 million with a stated return on equity of 10.3 percent. The increase in rates was implemented in April 2009.

In November 2008, the Mid-Tex Division filed a statement of intent to increase operating income for customers within the City of Dallas by $9.1 million. The City of Dallas suspended the filing on December 10, 2008 and denied the increase in March 2009. The Company has appealed the filing and in April 2009 we requested an increase in operating income of $7.5 million and concurrently filed for a statement of intent to increase operating income $1.3 million applicable to the Mid-Tex unincorporated areas. A final ruling by the Railroad Commission of Texas (RRC) is expected by October 2009. If the statement of intent applicable to the

City of Dallas is approved by the RRC, the new rates implemented could supersede the City of Dallas GRIP rates discussed above.

In April 2009, the Kentucky/Mid-States Division filed an expedited rate case with the Virginia State Corporation Commission seeking an increase in operating income of $1.7 million. Interim rates will be implemented subject to refund on May 1, 2009. The application is currently in discovery with a final determination expected in October 2009.

Other Ratemaking Activity

In May 2007, our Mid-Tex Division filed for a 36-month gas contract review filing. This filing was mandated by prior RRC orders and related to the prudency of gas purchases made from November 2003 through October 2006, which total approximately $2.7 billion. The intervening parties recommended disallowances ranging from $58 million to $89 million. A hearing was held at the RRC in September 2008. In December 2008, a proposal for decision was issued by the Hearing Examiner recommending no gas cost disallowance. In February 2009, the RRC approved the Hearing Examiner's recommendation to disallow no gas costs.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2009 and 2008 are presented below.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 27,061	$ 28,260	$ (1,199)
Third-party transportation	23,846	18,229	5,617
Storage and park and lend services	2,657	1,862	795
Other	5,670	3,089	2,581
Gross profit	59,234	51,440	7,794
Operating expenses	24,905	21,378	3,527
Operating income	34,329	30,062	4,267
Miscellaneous income	283	209	74
Interest charges	7,349	6,776	573
Income before income taxes	27,263	23,495	3,768
Income tax expense	7,798	8,271	(473)
Net income	$ 19,465	$ 15,224	$ 4,241
Gross pipeline transportation volumes — MMcf	193,356	223,476	(30,120)
Consolidated pipeline transportation volumes — MMcf	123,285	141,108	(17,823)

The $7.8 million increase in gross profit was attributable primarily to a $3.6 million increase resulting from higher transportation fees on through-system deliveries due to market conditions and a $3.3 million increase from higher demand-based fees. The improvement in gross profit also reflects a $2.9 million gain on the routine sale of excess gas during the quarter and a $1.4 million increase due to our 2006 and 2007 GRIP filings. These increases were partially offset by a $4.1 million decrease arising from lower city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $3.5 million primarily due to increased employee and pipeline maintenance costs.

Results for the quarter also include the aforementioned $1.7 million tax benefit associated with updating the rates used to determine our deferred taxes.

Recent Ratemaking Developments

In February 2009, the Atmos Pipeline — Texas Division made a GRIP filing seeking an increase in operating income of $6.3 million. The filing was approved by the RRC and a final order was issued in April 2009.

Natural Gas Marketing Segment

Our natural gas marketing activities are conducted through Atmos Energy Marketing, LLC (AEM). AEM 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 financial instruments. 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 received for services we deliver.

Our asset optimization activities seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging 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 instruments at advantageous prices to lock in a gross profit margin. We also seek to 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. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time.

AEM continually manages its net physical position to attempt to increase in the future the potential economic gross profit that was created when the original transaction was executed. Therefore, AEM may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEM elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to economically hedge the original financial instruments. If AEM elects to defer the withdrawal of gas, it will reset its financial instruments by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on

the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEM also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the execution of the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the three months ended March 31, 2009 and 2008 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical (spot) and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 23,165	$ 26,195	$ (3,030)
Asset optimization	(2,073)	27,737	(29,810)
	21,092	53,932	(32,840)
Unrealized margins	2,452	(37,600)	40,052
Gross profit	23,544	16,332	7,212
Operating expenses	13,165	6,306	6,859
Operating income	10,379	10,026	353
Miscellaneous income	118	602	(484)
Interest charges	3,461	2,002	1,459
Income before income taxes	7,036	8,626	(1,590)
Income tax expense	3,688	3,347	341
Net income	$ 3,348	$ 5,279	$ (1,931)
Gross natural gas marketing sales volumes — MMcf	123,066	136,677	(13,611)
Consolidated natural gas marketing sales volumes — MMcf	104,973	120,023	(15,050)
Net physical position (Bcf)	21.9	20.7	1.2

The $7.2 million increase in our natural gas marketing segment's gross profit was driven primarily by a $40.1 million increase in unrealized margins. This increase reflects lower volatility during the current quarter

compared with the prior-year quarter between current cash prices used to value our physical inventory and future natural gas prices, which influence the prices used to value the financial instruments used to hedge our physical inventory.

The increase in unrealized margins was partially offset by a $29.8 million decrease in asset optimization margins. During the current quarter, as a result of falling current cash prices, AEM elected to defer storage withdrawals, reset the corresponding financial instruments and inject additional gas into storage to increase the potential gross profit it could realize in future periods from its asset optimization activities. Accordingly, AEM's results for the quarter reflect lower realized gains from storage withdrawals and the settlement of the associated financial instruments. In the prior-year quarter, AEM elected to withdraw storage and realize the corresponding storage withdrawal gains.

In addition, delivered gas margins decreased $3.0 million compared with the prior-year quarter largely attributable to a 10 percent decrease in gross sales volumes, primarily associated with lower industrial demand due to the current economic climate. Per-unit margins for the quarter were approximately two percent lower compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $6.9 million primarily due to an increase in legal and other administrative costs.

Economic Gross Profit

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before associated storage fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic gross profit, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement is referred to as the potential gross profit.[1] The following table presents AEM's economic gross profit and its potential gross profit at March 31, 2009, December 31, 2008 and September 30, 2008.

Period Ending	Net Physical Position	Economic Gross Profit	Associated Net Unrealized Gain	Potential Gross Profit[1]
	(Bcf)	(In millions)	(In millions)	(In millions)
March 31, 2009	21.9	$33.4	$ 2.4	$31.0
December 31, 2008	16.3	$20.7	$ 4.8	$15.9
September 30, 2008	8.0	$48.5	$36.4	$12.1

[1] Potential gross profit represents the increase in AEM's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include storage and other operating expenses and increased income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic gross profit or the potential gross profit will be fully realized in the future. We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides our investors a more comprehensive view of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone.

As of March 31, 2009, based upon AEM's planned inventory withdrawal schedule and associated planned settlement of financial instruments, the economic gross profit was $33.4 million. This amount will be reduced by $2.4 million of net unrealized gains recorded in the financial statements as of March 31, 2009 that will reverse when the inventory is withdrawn and the accompanying financial instruments are settled. Therefore, the potential gross profit was $31.0 million at March 31, 2009.

During the six months ended March 31, 2009, AEM increased its potential gross profit by $18.9 million to $31.0 million. In the first quarter, AEM withdrew gas and substantially realized the associated potential gross profit reported as of September 30, 2008. Since that time, as a result of falling current cash prices, AEM

has been deferring storage withdrawals and has been a net injector of gas into storage to increase the potential gross profit it could realize in future periods from its asset optimization activities. As a result of these activities, AEM has increased its net physical position by 13.9 Bcf since September 30, 2008. However, the captured spreads on these positions have been lower than those captured as of September 30, 2008, resulting in a lower economic gross profit compared to that time, but higher than the economic gross profit of $10.8 million as of March 31, 2008. This decrease from September 2008 to March 2009 was partially offset by lower unrealized gains associated with these positions primarily due to lower current cash prices.

The economic gross profit is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage 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 March 31, 2009 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted. Assuming AEM fully executes its plan in place on March 31, 2009, without encountering operational or other issues, we anticipate that approximately $1 million of the potential gross profit as of March 31, 2009 will be recognized in fiscal 2009 with the remaining $30 million expected to be recognized during the first six months of fiscal 2010.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM, but also provides limited third party transportation services.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are asset management plans with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements.

Further, APS owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods. Finally, APS manages our natural gas gathering operations, which were limited in nature as of March 31, 2009.

Results for this segment are impacted primarily by seasonal weather patterns and volatility in the natural gas markets. Additionally, this segment's results include an unrealized component as APS hedges its risk associated with its asset optimization activities.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the three months ended March 31, 2009 and 2008 are presented below.

	Three Months Ended March 31		
	2009	2008	Change
	(In thousands)		
Asset optimization	$15,157	$ 6,604	$ 8,553
Storage and transportation services	3,312	3,895	(583)
Other	350	1,113	(763)
Unrealized margins	(8,203)	(1,928)	(6,275)
Gross profit	10,616	9,684	932
Operating expenses	2,591	2,227	364
Operating income	8,025	7,457	568
Miscellaneous income	2,060	1,942	118
Interest charges	677	524	153
Income before income taxes	9,408	8,875	533
Income tax expense	4,794	3,500	1,294
Net income	$ 4,614	$ 5,375	$ (761)

Gross profit from our pipeline, storage and other segment increased $0.9 million primarily due to an $8.6 million increase in asset optimization margins resulting from larger realized gains from the settlement of financial positions associated with storage and trading activities and basis gains earned from utilizing controlled pipeline capacity. These increases were partially offset by a $6.3 million decrease in unrealized margins associated with our asset optimization activities due to a widening of the spreads between current cash prices and forward natural gas prices.

Operating expenses for the three months ended March 31, 2009 were consistent with the prior-year quarter.

Six Months Ended March 31, 2009 compared with Six Months Ended March 31, 2008

Natural Gas Distribution Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$665,464	$630,724	$ 34,740
Operating expenses	379,231	369,709	9,522
Operating income	286,233	261,015	25,218
Miscellaneous income	3,956	4,146	(190)
Interest charges	61,708	60,298	1,410
Income before income taxes	228,481	204,863	23,618
Income tax expense	76,772	79,043	(2,271)
Net income	$151,709	$125,820	$ 25,889
Consolidated natural gas distribution sales volumes — MMcf	213,006	220,335	(7,329)
Consolidated natural gas distribution transportation volumes — MMcf	69,397	73,479	(4,082)
Total consolidated natural gas distribution throughput — MMcf	282,403	293,814	(11,411)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.44	$ 0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 7.61	$ 8.26	$ (0.65)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the six months ended March 31, 2009 and 2008. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands)		
Mid-Tex	$133,052	$122,704	$10,348
Kentucky/Mid-States	46,429	44,043	2,386
Louisiana	34,366	31,168	3,198
West Texas	22,819	13,895	8,924
Mississippi	25,206	24,343	863
Colorado-Kansas	22,224	22,224	—
Other	2,137	2,638	(501)
Total	$286,233	$261,015	$25,218

The $34.7 million increase in natural gas distribution gross profit primarily reflects a net $37.2 million increase in rates. The net increase in rates was attributable primarily to the Mid-Tex Division, which increased $27.8 million as a result of the implementation of its 2008 Rate Review Mechanism (RRM) filing with all

incorporated cities in the division other than the City of Dallas (the Settled Cities) and rate adjustments for customers in the City of Dallas. The current year period also reflects a $9.4 million increase in rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas. The increase in gross profit also reflects the reversal of a $7.0 million uncollectible gas cost accrual recorded in a prior year and an $8.3 million increase attributable to a non-recurring update to our estimate for gas delivered to customers but not yet billed to reflect changes in base rates in several of our jurisdictions recorded in the fiscal first quarter. These increases in gross profit were partially offset by a $14.8 million decrease as a result of a four percent decrease in distribution throughput primarily associated with lower residential and commercial consumption and warmer weather in our Colorado service area, which does not have weather-normalized rates.

Partially offsetting these increases was a decrease of approximately $9.2 million in revenue-related taxes primarily due to lower revenues, on which the tax is calculated, in the current-year period compared to the prior-year period. This decrease, combined with a $7.3 million period-over-period increase in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a $16.5 million decrease in operating income when compared with the prior-year period.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased $9.5 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $4.7 million, primarily due to lower legal, fuel and other administrative costs. These decreases were partially offset by a $2.1 million noncash charge in the first quarter of fiscal 2009 to impair certain available-for-sale investments due to the recent deterioration of the financial markets.

Depreciation and amortization expense increased $8.7 million for the current-year period compared with six months ended March 31, 2008. The increase primarily was attributable to additional assets placed in service during the current-year period.

Results for the prior-year period also included a $1.2 million gain on the sale of irrigation assets in our West Texas Division.

Interest charges allocated to the natural gas distribution segment increased $1.4 million due to higher average short-term debt balances, interest rates and commitment fees experienced during the current-year period compared to the prior-year period. These increases are associated with the recent adverse conditions in the credit markets.

Results for the current-year period include the aforementioned $10.5 million tax benefit associated with updating the rates used to determine our deferred taxes.

Regulated Transmission and Storage Segment

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 51,413	$ 50,648	$ 765
Third-party transportation	49,212	36,461	12,751
Storage and park and lend services	5,014	3,901	1,113
Other	8,277	5,476	2,801
Gross profit	113,916	96,486	17,430
Operating expenses	60,217	44,170	16,047
Operating income	53,699	52,316	1,383
Miscellaneous income	1,098	383	715
Interest charges	15,428	13,847	1,581
Income before income taxes	39,369	38,852	517
Income tax expense	12,243	13,781	(1,538)
Net income	$ 27,126	$ 25,071	$ 2,055
Gross pipeline transportation volumes — MMcf	385,528	412,340	(26,812)
Consolidated pipeline transportation volumes — MMcf	259,143	277,308	(18,165)

The $17.4 million increase in gross profit was attributable primarily to a $7.6 million increase resulting from higher transportation fees on through-system deliveries due to market conditions and a $6.4 million increase from higher demand-based fees. The improvement in gross profit also reflects a $2.9 million gain on the sale of excess gas during the current-year period and a $2.7 million increase due to our 2006 and 2007 GRIP filings. These increases were partially offset by a $3.4 million decrease associated with lower city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $16.0 million primarily due to increased employee and pipeline maintenance costs.

Results for the current-year period also include the aforementioned $1.7 million tax benefit associated with updating the rates used to determine our deferred taxes.

Natural Gas Marketing Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 41,718	$ 44,368	$ (2,650)
Asset optimization	34,866	27,212	7,654
	76,584	71,580	5,004
Unrealized margins	(23,017)	(9,285)	(13,732)
Gross profit	53,567	62,295	(8,728)
Operating expenses	22,675	17,570	5,105
Operating income	30,892	44,725	(13,833)
Miscellaneous income	419	1,398	(979)
Interest charges	7,363	3,316	4,047
Income before income taxes	23,948	42,807	(18,859)
Income tax expense	10,025	16,928	(6,903)
Net income	$ 13,923	$ 25,879	$(11,956)
Gross natural gas marketing sales volumes — MMcf	233,724	245,386	(11,662)
Consolidated natural gas marketing sales volumes — MMcf	198,281	216,229	(17,948)
Net physical position (Bcf)	21.9	20.7	1.2

The $8.7 million decrease in our natural gas marketing segment's gross profit was driven primarily by a $13.7 million decrease in unrealized margins. This decrease reflects higher volatility during the current period between current cash prices used to value our physical inventory and future natural gas prices, which influence the prices used to value the financial instruments used to hedge our physical inventory.

Additionally, realized delivered gas margins decreased by $2.7 million. The decrease was largely attributable to a five percent decrease in gross sales volumes primarily associated with lower industrial demand due to the current economic climate combined with a one percent decrease in per-unit margins, compared with the prior-year period.

The decrease in unrealized margins and delivered gas margins was partially offset by a $7.7 million increase in asset optimization margins. During the first quarter of fiscal 2009, AEM withdrew physical storage inventory and realized the spreads it had captured during fiscal 2008 as a result of deferring storage withdrawals and increasing the spreads associated with those physical positions. These gains were partially offset by the margin loss incurred in the second quarter as a result of deferring storage withdrawals and injecting gas into storage. In the prior-year period, AEM deferred storage withdrawals from the first quarter into the second quarter, and recognized the storage withdrawal gains during the second quarter of fiscal 2008.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $5.1 million primarily due to an increase in legal and other administrative costs partially offset by the absence in the current year of $2.4 million related to tax matters incurred in the prior-year period.

Pipeline, Storage and Other Segment

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the six months ended March 31, 2009 and 2008 are presented below.

	Six Months Ended March 31		
	2009	2008	Change
	(In thousands)		
Asset optimization	$20,624	$ 6,374	$14,250
Storage and transportation services	6,627	7,023	(396)
Other	1,339	1,840	(501)
Unrealized margins	(5,429)	445	(5,874)
Gross profit	23,161	15,682	7,479
Operating expenses	4,416	4,258	158
Operating income	18,745	11,424	7,321
Miscellaneous income	4,221	3,970	251
Interest charges	1,413	1,223	190
Income before income taxes	21,553	14,171	7,382
Income tax expense	9,345	5,604	3,741
Net income	$12,208	$ 8,567	$ 3,641

Gross profit from our pipeline, storage and other segment increased $7.5 million primarily due to a $14.3 million increase in asset optimization margins as a result of larger realized gains from the settlement of financial positions associated with storage and trading activities, basis gains earned from utilizing controlled pipeline capacity and higher margins earned under asset management plans during the current-year period compared with the prior-year period. These increases were partially offset by a $5.9 million decrease in unrealized margins associated with our asset optimization activities due to a widening of the spreads between current cash prices and forward natural gas prices.

Operating expenses for the six months ended March 31, 2009 were consistent with the prior-year period.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

The primary means we use to fund our working capital needs and growth is to utilize internally generated funds and to access the commercial paper markets. Recent adverse developments in global financial and credit markets have made it more difficult and more expensive for the Company to access the short-term capital markets, including the commercial paper market, to satisfy our liquidity requirements. Consequently, during the first quarter, we experienced higher than normal borrowings under our five-year credit facility used to backstop our commercial paper program in lieu of commercial paper borrowings to fund our working capital needs. However, subsequent to the end of the first quarter, credit market conditions improved, both as to availability and interest rates, and we have been able to access the commercial paper markets on more reasonably economical terms. At March 31, 2009, there were no borrowings or commercial paper outstanding under this facility and $566.7 million was available.

On March 26, 2009, we closed our offering of $450 million of 8.50% senior notes due 2019. Most of the net proceeds of approximately $446 million were used to redeem our $400 million 4.00% unsecured senior notes, which, on March 30, 2009, were called for redemption on April 30, 2009, prior to their October 2009 maturity. In connection with the repayment of the $400 million 4.00% unsecured senior notes, we paid a $6.6 million call premium in accordance with the terms of the senior notes and accrued interest of approximately $0.6 million. The remaining net proceeds will be used for general corporate purposes.

During the six months ended March 31, 2009, we increased our liquidity sources in various ways. In October 2008, we replaced our former $300 million 364-day committed credit facility with a new facility that will allow borrowings up to $212.5 million and expires in October 2009. In December 2008, we converted AEM's former $580 million uncommitted credit facility to a $375 million committed credit facility that will expire in December 2009. Effective April 1, 2009, we exercised the accordion feature of this facility to increase the credit available under the facility to $450 million. In addition, we replaced our $18 million unsecured committed credit facility that expired in March 2009 with a $25 million unsecured facility effective April 1, 2009. As a result of executing these new agreements, we will have a total of approximately $1.3 billion available to us under four committed credit facilities beginning April 1, 2009. As of March 31, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $998 million.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2009.

Cash Flows

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

Cash flows from operating activities

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

For the six months ended March 31, 2009, we generated operating cash flow of $614.6 million from operating activities compared with $479.2 million for the six months ended March 31, 2008. Period over period, the $135.4 million increase was attributable primarily to the favorable impact on our working capital due to the decline in natural gas prices in the current year compared to the prior-year period which increased operating cash flow by $61.2 million, coupled with a $51.9 million increase due to the favorable timing in the recovery of gas costs during the current year.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund growth projects, our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return on our investment. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution 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 being required to file a rate case.

Capital expenditures for fiscal 2009 are expected to range from $500 million to $515 million. For the six months ended March 31, 2009, capital expenditures were $221.3 million compared with $198.7 million for the six months ended March 31, 2008. The increase in capital spending primarily reflects spending for a nonregulated growth project and the construction of a pipeline extension in our regulated operations.

Cash flows from financing activities

For the six months ended March 31, 2009, our financing activities provided $46.0 million compared with a use of cash of $198.4 million in the prior-year period. Our significant financing activities for the six months ended March 31, 2009 and 2008 are summarized as follows:

- On March 26, 2009, we issued $450 million of 8.50% senior notes due 2019. The effective interest rate of this offering, inclusive of all debt issue costs, was 8.74 percent. After giving effect to the settlement of our $450 million Treasury lock agreement on March 23, 2009, the effective rate on these senior notes was reduced to 8.69 percent. Most of the net proceeds of approximately $446 million were used to repay our $400 million unsecured 4.00% senior notes, which were called on March 30, 2009 for redemption on April 30, 2009.
- During the six months ended March 31, 2009, we decreased our borrowings by a net $353.5 million under our short-term credit facilities compared with $150.6 million in the prior-year period. The reduction in the net borrowings reflects the timing of the use of our line of credit to finance natural gas purchases and working capital.
- We repaid $0.6 million of long-term debt during the six months ended March 31, 2009 compared with $2.3 million during the six months ended March 31, 2008. Payments in both periods reflected regularly scheduled payments in accordance with our various debt agreements.
- During the six months ended March 31, 2009, we paid $60.4 million in cash dividends compared with $58.4 million for the six months ended March 31, 2008. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.65 per share during the six months ended March 31, 2008 to $0.66 per share during the six months ended March 31, 2009 combined with new share issuances under our various equity plans.
- During the six months ended March 31, 2009, we issued 0.6 million shares of common stock under our various equity plans, which generated net proceeds of $12.4 million. In addition, we issued 0.5 million shares of common stock under our 1998 Long-Term Incentive Plan.

The following table summarizes our share issuances for the six months ended March 31, 2009 and 2008.

	Six Months Ended March 31	
	2009	**2008**
Shares issued:		
Direct Stock Purchase Plan	220,361	203,025
Retirement Savings Plan and Trust	330,990	268,712
1998 Long-Term Incentive Plan	579,990	343,500
Outside Directors Stock-for-Fee Plan	1,590	1,602
Total shares issued	1,132,931	816,839

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. As of March 31, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $998 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

On March 23, 2009, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $450 million of capacity carried over from our prior shelf registration statement filed with the SEC in December 2006. Immediately following the filing of the registration statement, we issued $450 million of 8.50% senior notes due 2019 under the registration statement. Most of the net proceeds of approximately $446 million were used to repay our $400 million unsecured 4.00% senior notes, which were called on March 30, 2009 for redemption on April 30, 2009.

As of March 31, 2009, we had $450 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $300 million of equity securities and $150 million of subordinated debt securities.

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 regulated and nonregulated 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). In December 2008, S&P upgraded our credit rating from BBB to BBB+ and affirmed a stable outlook. S&P cited improved financial performance and rate case decisions that have increased cash flow as the key drivers for the upgrade. In January 2009, Moody's changed our rating outlook from stable to positive. Additionally, our credit rating is currently under review for a possible upgrade by Moody's. Fitch still maintains its stable outlook. 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

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of the recent adverse global financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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 March 31, 2009. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization as of March 31, 2009, September 30, 2008 and March 31, 2008:

	March 31, 2009		September 30, 2008		March 31, 2008	
	(In thousands, except percentages)					
Short-term debt	$ —	—%	$ 350,542	7.7%	$ —	—%
Long-term debt	2,569,366	54.1%	2,120,577	46.9%	2,128,149	50.0%
Shareholders' equity	2,178,494	45.9%	2,052,492	45.4%	2,125,993	50.0%
Total capitalization	$4,747,860	100.0%	$4,523,611	100.0%	$4,254,142	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 54.1 percent at March 31, 2009, 54.6 percent at September 30, 2008 and 50.0 percent at March 31, 2008. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. The increase in the debt to capital ratio compared to March 31, 2008 is due to the timing of the repayment of our $400 million unsecured 4.00% unsecured senior notes. Had we repaid the notes as of March 31, 2009, our total-debt-to-capital ratio would have been 49.9 percent. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and access to the equity capital markets.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2009.

In February 2008, Atmos Pipeline and Storage, LLC announced plans to construct and operate a salt-cavern gas storage project in Franklin Parish, Louisiana. The project, located near several large interstate pipelines, includes the development of three 5 billion cubic feet (Bcf) caverns for a total of 15 Bcf of working gas storage, with six-turn injection and withdrawal capacity. Testing of the salt core samples was completed in March 2009 which showed favorable conditions for development. We have filed a 7C application with the Federal Energy Regulatory Commission (FERC) to construct and operate the project and expect approval of this request in June 2009. Finally, we have engaged the services of an investment bank to assist us in determining the optimal ownership and/or development alternatives for this project, which is still in process.

Risk Management Activities

We conduct risk management activities through our natural gas distribution, natural gas marketing and pipeline, storage and other segments. In our natural gas distribution segment, we use a combination of physical 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 and pipeline, storage and other segments, 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and six months ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$(51,314)	$(21,528)	$ (63,677)	$(21,053)
Contracts realized/settled	(47,231)	(4,972)	(100,996)	(27,310)
Fair value of new contracts	277	1,401	(4,006)	(280)
Other changes in value	76,405	34,604	146,816	58,148
Fair value of contracts at end of period	$(21,863)	$ 9,505	$ (21,863)	$ 9,505

The fair value of our natural gas distribution segment's financial instruments at March 31, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2009				
	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	$(21,859)	$ (4)	$—	$—	$(21,863)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(21,859)	$ (4)	$—	$—	$(21,863)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the three and six months ended March 31, 2009 and 2008:

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$(28,598)	$ 51,859	$ 16,542	$ 26,808
Contracts realized/settled	6,972	(46,331)	(13,275)	(41,256)
Fair value of new contracts	—	—	—	—
Other changes in value	(11,020)	(28,503)	(35,913)	(8,527)
Fair value of contracts at end of period	(32,646)	(22,975)	(32,646)	(22,975)
Netting of cash collateral	79,098	29,591	79,098	29,591
Cash collateral and fair value of contracts at period end	$ 46,452	$ 6,616	$ 46,452	$ 6,616

The fair value of our natural gas marketing segment's financial instruments at March 31, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2009				
	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	$(42,372)	$9,726	$—	$—	$(32,646)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(42,372)	$9,726	$—	$—	$(32,646)

Pension and Postretirement Benefits Obligations

Effective October 1, 2008, the Company adopted the requirement under SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* that the measurement date used to determine our projected benefit and postretirement obligations and net periodic pension and postretirement costs must correspond to a fiscal year end. In accordance with the transition rules, the impact of changing the measurement date from June 30, 2008 to September 30, 2008 decreased retained earnings by $7.8 million, net of tax, decreased the unrecognized actuarial loss by $9.0 million and increased our postretirement liabilities by $3.5 million.

Further, our fiscal 2009 costs were determined using a September 30, 2008 measurement date. As of September 30, 2008, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of June 30, 2007, the measurement date for our fiscal 2008 net periodic cost. Accordingly, we increased our discount rate used to determine our fiscal 2009 pension and benefit costs to 7.57 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is mitigated by the fact that assets are "smoothed" for purposes of determining net periodic pension cost. Accordingly, asset gains and losses are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Therefore, our fiscal 2009 pension and postretirement medical costs were materially the same as in fiscal 2008.

For the six months ended March 31, 2009 and 2008, our total net periodic pension and other benefits cost was $24.1 million and $23.9 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2009. Based upon this valuation, we expect we will be required to contribute less than $25 million to our pension plans by September 15, 2009. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during the latter half of calendar year 2008. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $10 million to these plans during fiscal 2009.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts are impacted by actual investment returns, changes in interest rates and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage, natural gas marketing and pipeline, storage and other segments for the three and six-month periods ended March 31, 2009 and 2008.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
METERS IN SERVICE, end of period				
Residential	2,937,865	2,933,980	2,937,865	2,933,980
Commercial	274,449	275,998	274,449	275,998
Industrial	2,212	2,269	2,212	2,269
Public authority and other	9,243	8,948	9,243	8,948
Total meters	3,223,769	3,221,195	3,223,769	3,221,195
INVENTORY STORAGE BALANCE — Bcf	31.9	34.4	31.9	34.4
SALES VOLUMES — MMcf[(1)]				
Gas sales volumes				
Residential	74,467	83,934	128,675	132,965
Commercial	36,689	40,506	65,018	67,126
Industrial	5,758	7,258	11,158	13,212
Public authority and other	4,646	3,870	8,155	7,032
Total gas sales volumes	121,560	135,568	213,006	220,335
Transportation volumes	36,169	40,938	71,454	75,791
Total throughput	157,729	176,506	284,460	296,126
OPERATING REVENUES (000's)[(1)]				
Gas sales revenues				
Residential	$ 785,456	$ 971,673	$1,432,556	$1,525,962
Commercial	334,815	421,708	637,509	690,177
Industrial	46,259	62,135	96,414	113,311
Public authority and other	36,991	37,244	68,385	67,848
Total gas sales revenues	1,203,521	1,492,760	2,234,864	2,397,298
Transportation revenues	16,889	17,786	32,655	32,791
Other gas revenues	10,010	11,310	18,869	19,944
Total operating revenues	$1,230,420	$1,521,856	$2,286,388	$2,450,033
Average transportation revenue per Mcf	$ 0.47	$ 0.43	$ 0.46	$ 0.43
Average cost of gas per Mcf sold	$ 7.10	$ 8.59	$ 7.61	$ 8.26

See footnote following these tables.

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

	Three Months Ended March 31		Six Months Ended March 31	
	2009	2008	2009	2008
CUSTOMERS, end of period				
Industrial	698	716	698	716
Municipal	61	61	61	61
Other	527	474	527	474
Total	1,286	1,251	1,286	1,251
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	20.4	19.6	20.4	19.6
Pipeline, storage and other	2.0	1.2	2.0	1.2
Total	22.4	20.8	22.4	20.8
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	193,356	223,476	385,528	412,340
NATURAL GAS MARKETING SALES VOLUMES — MMcf[(1)]	123,066	136,677	233,724	245,386
OPERATING REVENUES (000's)[(1)]				
Regulated transmission and storage	$ 59,234	$ 51,440	$ 113,916	$ 96,486
Natural gas marketing	708,658	1,128,653	1,496,153	1,969,370
Pipeline, storage and other	12,272	10,022	28,720	16,749
Total operating revenues	$780,164	$1,190,115	$1,638,789	$2,082,605

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the year ended September 30, 2008. During the six months ended March 31, 2009, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of March 31, 2009 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the

SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the six months ended March 31, 2009, except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

At the Annual Meeting of Shareholders of Atmos Energy Corporation on February 4, 2009, 79,385,275 votes were cast as follows:

	Votes For	Votes Withheld/ Against	Votes Abstaining
Class I Director:			
Ruben E. Esquivel	77,254,669	2,130,606	—
Class II Directors:			
Richard W. Cardin	77,675,895	1,709,380	—
Thomas C. Meredith	77,720,662	1,664,613	—
Nancy K. Quinn	78,057,677	1,327,598	—
Stephen R. Springer	77,027,075	2,358,200	—
Richard Ware II	77,735,952	1,649,323	—
Ratification of the Audit Committee's engagement of Ernst & Young LLP to serve as the Company's registered independent public accounting firm for fiscal year 2009	78,424,677	767,618	192,980
Shareholder proposal regarding declassification of the Board of Directors	45,212,206	17,596,650	527,384

Mr. Dan Busbee, a Class I director, retired on February 4, 2009, at the conclusion of the Annual Meeting of Shareholders, in accordance with the Board's mandatory retirement policy. The remaining directors will continue to serve until the expiration of their terms. The term of the Class I directors, Travis W. Bain II, Richard W. Douglas, Ruben E. Esquivel and Richard K. Gordon, will expire in 2011. The term of the Class II directors, Richard W. Cardin, Thomas C. Meredith, Nancy K. Quinn, Stephen R. Springer and Richard Ware II, will expire in 2012. The term of the Class III directors, Robert W. Best, Thomas J. Garland, Phillip E. Nichol and Charles K. Vaughan, will expire in 2010.

Item 6. ***Exhibits***

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

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President, Chief Financial Officer and Controller
(Duly authorized signatory)

Date: May 1, 2009

EXHIBITS INDEX
Item 6

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.

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, 2009

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).* Yes ☐ No ☐

* The registrant has not yet been phased into the interactive data requirements.

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

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

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, 2009.

Class	Shares Outstanding
No Par Value	92,272,478

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
FSP	FASB Staff Position
GRIP	Gas Reliability Infrastructure Program
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MPSC	Mississippi Public Service Commission
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2009	September 30, 2008
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,963,098	$5,730,156
Less accumulated depreciation and amortization	1,623,734	1,593,297
Net property, plant and equipment	4,339,364	4,136,859
Current assets		
Cash and cash equivalents	125,735	46,717
Accounts receivable, net	241,582	477,151
Gas stored underground	317,275	576,617
Other current assets	111,420	184,619
Total current assets	796,012	1,285,104
Goodwill and intangible assets	738,615	739,086
Deferred charges and other assets	222,039	225,650
	$6,096,030	$6,386,699
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, 2009 — 92,234,134 shares; September 30, 2008 — 90,814,683 shares	$ 461	$ 454
Additional paid-in capital	1,779,184	1,744,384
Retained earnings	451,856	343,601
Accumulated other comprehensive loss	(39,981)	(35,947)
Shareholders' equity	2,191,520	2,052,492
Long-term debt	2,169,395	2,119,792
Total capitalization	4,360,915	4,172,284
Current liabilities		
Accounts payable and accrued liabilities	221,968	395,388
Other current liabilities	422,200	460,372
Short-term debt	—	350,542
Current maturities of long-term debt	131	785
Total current liabilities	644,299	1,207,087
Deferred income taxes	510,901	441,302
Regulatory cost of removal obligation	322,529	298,645
Deferred credits and other liabilities	257,386	267,381
	$6,096,030	$6,386,699

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 386,985	$ 676,639
Regulated transmission and storage segment	49,345	46,286
Natural gas marketing segment	453,504	1,189,722
Pipeline, storage and other segment	8,226	3,880
Intersegment eliminations	(117,285)	(277,382)
	780,775	1,639,145
Purchased gas cost		
Natural gas distribution segment	195,303	476,711
Regulated transmission and storage segment	—	—
Natural gas marketing segment	438,482	1,192,353
Pipeline, storage and other segment	4,212	706
Intersegment eliminations	(116,862)	(276,847)
	521,135	1,392,923
Gross profit	259,640	246,222
Operating expenses		
Operation and maintenance	110,895	117,822
Depreciation and amortization	54,181	50,356
Taxes, other than income	47,577	57,335
Asset impairments	3,304	—
Total operating expenses	215,957	225,513
Operating income	43,683	20,709
Miscellaneous income	1,219	1,600
Interest charges	41,511	33,470
Income (loss) before income taxes	3,391	(11,161)
Income tax expense (benefit)	1,427	(4,573)
Net income (loss)	$ 1,964	$ (6,588)
Basic net income (loss) per share	$ 0.02	$ (0.07)
Diluted net income (loss) per share	$ 0.02	$ (0.07)
Cash dividends per share	$ 0.330	$ 0.325
Weighted average shares outstanding:		
Basic	91,338	89,648
Diluted	92,002	89,648

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,673,373	$3,126,672
Regulated transmission and storage segment	163,261	142,772
Natural gas marketing segment	1,949,657	3,159,092
Pipeline, storage and other segment	36,946	20,629
Intersegment eliminations	(504,724)	(668,525)
	4,318,513	5,780,640
Purchased gas cost		
Natural gas distribution segment	1,816,227	2,296,020
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,881,068	3,099,428
Pipeline, storage and other segment	9,771	1,773
Intersegment eliminations	(503,456)	(666,835)
	3,203,610	4,730,386
Gross profit	1,114,903	1,050,254
Operating expenses		
Operation and maintenance	365,312	359,064
Depreciation and amortization	160,757	147,659
Taxes, other than income	150,028	153,170
Asset impairments	5,382	—
Total operating expenses	681,479	659,893
Operating income	433,424	390,361
Miscellaneous income (expense)	(647)	2,974
Interest charges	116,035	103,803
Income before income taxes	316,742	289,532
Income tax expense	109,812	110,783
Net income	$ 206,930	$ 178,749
Basic net income per share	$ 2.28	$ 2.00
Diluted net income per share	$ 2.26	$ 1.99
Cash dividends per share	$ 0.990	$ 0.975
Weighted average shares outstanding:		
Basic	90,940	89,281
Diluted	91,590	89,937

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2009	2008
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 206,930	$ 178,749
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	160,757	147,659
Charged to other accounts	60	106
Deferred income taxes	62,658	77,864
Other	23,009	12,767
Net assets/liabilities from risk management activities	53,711	(78,524)
Net change in operating assets and liabilities	317,469	78,760
Net cash provided by operating activities	824,594	417,381
Cash Flows From Investing Activities		
Capital expenditures	(342,326)	(312,878)
Other, net	(6,094)	(4,303)
Net cash used in investing activities	(348,420)	(317,181)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(366,449)	(35,721)
Net proceeds from debt offering	445,623	—
Settlement of Treasury lock agreement	1,938	—
Repayment of long-term debt	(407,287)	(9,945)
Cash dividends paid	(90,909)	(87,821)
Issuance of common stock	19,928	19,063
Net cash used in financing activities	(397,156)	(114,424)
Net increase (decrease) in cash and cash equivalents	79,018	(14,224)
Cash and cash equivalents at beginning of period	46,717	60,725
Cash and cash equivalents at end of period	$ 125,735	$ 46,501

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2009

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[(1)]
Atmos Energy Kentucky/Mid-States Division	Georgia[(1)], Illinois[(1)], Iowa[(1)], Kentucky, Missouri[(1)], Tennessee, Virginia[(1)]
Atmos Energy Louisiana Division	Louisiana
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 states where we have more limited service areas.

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

Our regulated transmission and storage business consists of the regulated operations of our Atmos Pipeline — Texas Division. 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 to the pipeline industry including parking arrangements, lending services and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands.

Our nonregulated businesses operate primarily in the Midwest and Southeast and include our natural gas marketing operations and pipeline, storage and other operations. These businesses are operated through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH), which is wholly owned by the Company and based in Houston, Texas.

Our natural gas marketing operations are conducted through 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 Southeast and Midwest and to our Colorado-Kansas, Kentucky/Mid-States and Louisiana 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 financial instruments.

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is used primarily to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM, but also provides limited third party transportation services.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are asset management plans with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements.

Further, APS owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods. Finally, APS manages our natural gas gathering operations, which were limited in nature as of June 30, 2009.

2. Unaudited Interim Financial Information

In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2009 are not indicative of our results of operations for the full 2009 fiscal year, which ends September 30, 2009.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008 and there have been no changes to those policies. However, during the nine months ended June 30, 2009, we recognized a non-recurring $7.8 million increase in gross profit associated with a one-time update to our estimate for gas delivered to customers but not yet billed, resulting from base rate changes in several jurisdictions.

During the second quarter of fiscal 2009, we updated the tax rates used to record deferred taxes. The one-time tax benefit resulted in a favorable impact to net income of $11.3 million.

Additionally, during the second quarter of fiscal 2009, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

Effective October 1, 2008, the Company adopted Statement of Financial Accounting Standards (SFAS) 157, *Fair Value Measurements*, the measurement date requirements of SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115* and SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133.* Effective April 1, 2009, the Company adopted FASB Staff Position (FSP) FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments,* FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments,* FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* and SFAS 165, *Subsequent Events.* Except for the adoption of these accounting pronouncements, which are further discussed below, there were no significant changes to our accounting policies during the nine months ended June 30, 2009.

SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosure on fair value measurements required under other accounting pronouncements but does not change existing guidance as to whether or not an instrument is carried at fair value. The adoption of this standard did not materially impact our financial position, results of operations or cash flows. The new disclosures required by this standard are presented in Note 4.

Effective October 1, 2008, the Company adopted the measurement date requirements of SFAS 158 using the remeasurement approach. Under this approach, the Company remeasured our projected benefit obligation, fair value of plan assets and our fiscal 2009 net periodic cost. In accordance with the transition rules of SFAS 158, the impact of changing the measurement date from June 30, 2008 to September 30, 2008 decreased retained earnings by $7.8 million, net of tax, decreased the unrecognized actuarial loss by $9.0 million and increased our postretirement liabilities by $3.5 million during the first quarter of fiscal 2009.

SFAS 159 permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of the standard is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Entities that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option may be elected on an instrument-by-instrument basis. The fair value option is irrevocable, unless a new election date occurs. The adoption of this standard did not impact our financial position, results of operations or cash flows.

SFAS 161 expands the disclosure requirements for derivative instruments and hedging activities. This statement requires specific disclosures regarding how and why an entity uses derivative instruments; the accounting for derivative instruments and related hedged items; and how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. Since SFAS 161 only requires additional disclosures concerning derivatives and hedging activities, this standard did not have an impact on our financial position, results of operations or cash flows. The new disclosures required by this standard are presented in Note 3.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. This FSP requires companies to disclose the fair value of financial instruments for which it is practicable to estimate the value and the methods and significant assumptions used to estimate the fair value. The disclosure is required for interim and annual reports. The disclosure requirements of this FSP are presented in Note 4.

In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*. This FSP amends the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. This FSP does not amend existing recognition and measurement guidance related to other-than-temporary impairments of equity securities. In addition, FSP FAS 115-2 and FAS 124-2 expands the existing disclosure requirements about debt and equity securities to interim reporting as well as provides new disclosure requirements. We adopted the provisions of this FSP for the quarter ended June 30, 2009. The adoption of FSP FAS 115-2 and FAS 124-2 did not impact our financial position, results of operations or cash flows. The disclosure requirements of this FSP are presented in Note 7.

In April 2009, the FASB issued FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly.* This FSP provides further guidance for estimating fair value in accordance with SFAS 157 when there has been a significant decrease in market activity for a financial asset and also identifies circumstances that indicate a transaction is not orderly. The adoption of this FSP did not impact our financial position, results of operations or cash flows.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*. SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before the date the financial statements are issued or available to be issued. SFAS 165 requires companies to reflect in their financial statements the effects of subsequent events that provide additional evidence about conditions at the balance-sheet date. Subsequent events that provide evidence about conditions that arose after the balance-sheet date should be disclosed if the financial statements would otherwise be misleading. We adopted the provisions of SFAS 165 for quarter ended June 30, 2009. We have evaluated subsequent events from the balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

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

Significant regulatory assets and liabilities as of June 30, 2009 and September 30, 2008 included the following:

	June 30, 2009	September 30, 2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 88,472	$100,563
Merger and integration costs, net	7,268	7,586
Deferred gas costs	24,355	55,103
Environmental costs	685	980
Rate case costs	7,640	12,885
Deferred franchise fees	577	651
Deferred income taxes, net	343	343
Other	7,085	8,120
	$136,425	$186,231
Regulatory liabilities:		
Deferred gas costs	$ 97,495	$ 76,979
Regulatory cost of removal obligation	336,737	317,273
Other	5,429	5,639
	$439,661	$399,891

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

Comprehensive income

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and nine-month periods ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Net income (loss)	$ 1,964	$(6,588)	$206,930	$178,749
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $1,282 and $531 for the three months ended June 30, 2009 and 2008 and of $(2,477) and $(140) for the nine months ended June 30, 2009 and 2008	2,086	866	(4,209)	(231)
Other than temporary impairment of investments, net of tax expense of $1,222 and $2,012 for the three and nine months ended June 30, 2009	2,082	—	3,370	—
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $320 and $482 for the three months ended June 30, 2009 and 2008 and $2,155 and $1,446 for the nine months ended June 30, 2009 and 2008	543	787	3,184	2,361
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $16,582 and $1,850 for the three months ended June 30, 2009 and 2008 and $(4,759) and $9,047 for the nine months ended June 30, 2009 and 2008	25,936	3,018	(6,379)	14,761
Comprehensive income (loss)	$32,611	$(1,917)	$202,896	$195,640

Accumulated other comprehensive loss, net of tax, as of June 30, 2009 and September 30, 2008 consisted of the following unrealized gains (losses):

	June 30, 2009	September 30, 2008
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 71	$ 910
Treasury lock agreements	(7,920)	(11,104)
Cash flow hedges	(32,132)	(25,753)
	$(39,981)	$(35,947)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. However, our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from

an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

In our natural gas distribution segment, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. If the regulatory authority does not establish this level, we typically seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2008-2009 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 27 percent, or 24.3 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with SFAS 71. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

Our natural gas marketing segment, through AEM, 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.

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. We also seek to participate in transactions in which we combine the natural gas commodity and transportation costs to minimize 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. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 43 months. The effective portion of the unrealized gains and losses arising from the use of cash flow hedges is recorded as a component of accumulated other comprehensive income (AOCI) on the balance sheet. Amounts associated with cash flow hedges recognized in the income statement include (i) the amount of unrealized gain or loss that has been reclassified from AOCI when the hedged volumes are sold and (ii) the amount of ineffectiveness associated with these hedges in the period the ineffectiveness arises.

We use financial instruments, designated as fair value hedges, to hedge the exposure to changes in the fair value of our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments. Therefore, gains and losses arising from these financial instruments should offset the changes in the fair value of the hedged item to the extent the hedging relationship is effective. Ineffectiveness is recognized in the income statement in the period the ineffectiveness arises.

Our natural gas marketing segment also uses storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on June 30, 2009, AEH had net open positions (including existing storage) of 0.3 Bcf.

Interest Rate Risk Management Activities

In March 2009, we entered into a Treasury lock agreement to fix the Treasury yield component of the interest cost associated with our $450 million 8.50% senior notes (the Senior Notes Offering), which was completed on March 26, 2009. The Senior Notes Offering is discussed in Note 5. We designated this Treasury

lock as a cash flow hedge of an anticipated transaction. This Treasury lock was settled on March 23, 2009 with the receipt of $1.9 million from the counterparty due to an increase in the 10 year Treasury rates between inception of the Treasury lock and settlement. Because the Treasury lock was effective, the net $1.2 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 10 year life of the senior notes.

In prior years, we similarly managed interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts of these Treasury locks will be recognized through fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of June 30, 2009, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2009, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other
			Quantity (MMcf)	
Commodity contracts	Fair Value	—	(22,905)	(2,050)
	Cash Flow	—	31,993	(4,118)
	Not designated	21,702	84,606	(51)
		21,702	93,694	(6,219)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of June 30, 2009 and September 30, 2008. As required by SFAS 161, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $20.6 million and $56.6 million of cash held on deposit in margin accounts as of June 30, 2009 and September 30, 2008 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will

not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
June 30, 2009:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 71,992	$ 71,992
Noncurrent commodity contracts	Deferred charges and other assets	—	6,383	6,383
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(71,878)	(71,878)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,150)	(1,150)
Total		—	5,347	5,347
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	1,233	28,887	30,120
Noncurrent commodity contracts	Deferred charges and other assets	—	6,381	6,381
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(22,945)	(20,428)	(43,373)
Noncurrent commodity contracts	Deferred credits and other liabilities	(316)	(1,743)	(2,059)
Total		(22,028)	13,097	(8,931)
Total Financial Instruments		$(22,028)	$ 18,444	$ (3,584)

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
September 30, 2008:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$101,191	$101,191
Noncurrent commodity contracts	Deferred charges and other assets	—	4,984	4,984
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(89,397)	(89,397)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(206)	(206)
Total		—	16,572	16,572
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	—	20,010	20,010
Noncurrent commodity contracts	Deferred charges and other assets	—	1,093	1,093
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(58,566)	(20,145)	(78,711)
Noncurrent commodity contracts	Deferred credits and other liabilities	(5,111)	(988)	(6,099)
Total		(63,677)	(30)	(63,707)
Total Financial Instruments		$(63,677)	$ 16,542	$ (47,135)

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our condensed consolidated income statement, by operating segment, as applicable, for the three and nine months ended June 30, 2009 and 2008.

Hedge ineffectiveness for our natural gas marketing and pipeline storage and other segments is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended June 30, 2009 and 2008 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $0.2 million and $(4.7) million. For the nine months ended June 30, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $24.7 million and $40.6 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and nine months ended June 30, 2009 and 2008 is presented below.

	Three Months Ended June 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$2,710	$1,390	$4,100
Fair value adjustment for natural gas inventory designated as the hedged item	3,929	(741)	3,188
Total impact on revenue	$6,639	$ 649	$7,288
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 678	$ —	$ 678
Timing ineffectiveness	5,961	649	6,610
	$6,639	$ 649	$7,288

	Three Months Ended June 30, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$(50,391)	$(2,049)	$(52,440)
Fair value adjustment for natural gas inventory designated as the hedged item	46,765	1,431	48,196
Total impact on revenue	$ (3,626)	$ (618)	$ (4,244)
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (2,402)	$ —	$ (2,402)
Timing ineffectiveness	(1,224)	(618)	(1,842)
	$ (3,626)	$ (618)	$ (4,244)

	Nine Months Ended June 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 48,263	$ 7,435	$ 55,698
Fair value adjustment for natural gas inventory designated as the hedged item	(26,493)	(2,731)	(29,224)
Total impact on revenue	$ 21,770	$ 4,704	$ 26,474
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 4,958	$ —	$ 4,958
Timing ineffectiveness	16,812	4,704	21,516
	$ 21,770	$ 4,704	$ 26,474

	Nine Months Ended June 30, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ (66,612)	$ (662)	$ (67,274)
Fair value adjustment for natural gas inventory designated as the hedged item	104,288	3,841	108,129
Total impact on revenue	$ 37,676	$3,179	$ 40,855
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (1,185)	$ —	$ (1,185)
Timing ineffectiveness	38,861	3,179	42,040
	$ 37,676	$3,179	$ 40,855

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot to forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2009 and 2008 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended June 30, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(36,669)	$(2,503)	$(39,172)
Loss arising from ineffective portion of commodity contracts	—	(7,120)	—	(7,120)
Total impact on revenue	—	(43,789)	(2,503)	(46,292)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(863)	—	—	(863)
Total Impact from Cash Flow Hedges	$(863)	$(43,789)	$(2,503)	$(47,155)

	Three Months Ended June 30, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$10,040	$57	$10,097
Loss arising from ineffective portion of commodity contracts	—	(406)	—	(406)
Total impact on revenue	—	9,634	57	9,691
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)	—	—	(1,269)
Total Impact from Cash Flow Hedges	$(1,269)	$ 9,634	$57	$ 8,422

	Nine Months Ended June 30, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(142,986)	$25,213	$(117,773)
Loss arising from ineffective portion of commodity contracts	—	(1,748)	—	(1,748)
Total impact on revenue	—	(144,734)	25,213	(119,521)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(3,401)	—	—	(3,401)
Total Impact from Cash Flow Hedges	$(3,401)	$(144,734)	$25,213	$(122,922)

	Nine Months Ended June 30, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(3,744)	$9,334	$ 5,590
Loss arising from ineffective portion of commodity contracts	—	(281)	—	(281)
Total impact on revenue	—	(4,025)	9,334	5,309
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(3,807)	—	—	(3,807)
Total Impact from Cash Flow Hedges	$(3,807)	$(4,025)	$9,334	$ 1,502

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and nine months ended June 30, 2009 and 2008. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ —	$ —	$ 1,221	$ —
Forward commodity contracts	2,041	9,278	(78,220)	18,227
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	543	787	1,963	2,361
Forward commodity contracts	23,895	(6,260)	71,841	(3,466)
Total other comprehensive income (loss) from hedging, net of tax[1]	$26,479	$ 3,805	$ (3,195)	$17,122

[1] Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2009:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,687)	$(30,303)	$(31,990)
Thereafter	(6,233)	(1,829)	(8,062)
Total[1]	$(7,920)	$(32,132)	$(40,052)

[1] Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2009 and 2008 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact to our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Natural gas marketing commodity contracts	$ 6,167	$(12,786)	$12,928	$(26,580)
Pipeline, storage and other commodity contracts	(6,853)	2,594	(6,753)	1,705
Total impact on revenue	$ (686)	$(10,192)	$ 6,175	$(24,875)

4. Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP) and expands disclosures about fair value measurements. This Statement does not require any new fair value measurements; rather it provides guidance on how to perform fair value measurements as required or permitted under previous accounting pronouncements.

We prospectively adopted the provisions of SFAS 157 on October 1, 2008 for most of the financial assets and liabilities recorded on our balance sheet at fair value. Adoption of this statement for these assets and liabilities did not have a material impact on our financial position, results of operations or cash flows.

In February 2008, the FASB issued FSP FAS 157-2, *Effective Date of FASB Statement No. 157,* which provided a one-year deferral of SFAS 157 for nonrecurring fair value measurements associated with our nonfinancial assets and liabilities. Under this partial deferral, SFAS 157 will not be effective until October 1, 2009 for fair value measurements for the following:

- Asset retirement obligations
- Most nonfinancial assets and liabilities that may be acquired in a business combination
- Impairment analyses performed for nonfinancial assets

We believe the adoption of SFAS 157 for the reporting of these nonfinancial assets and liabilities will not have a material impact on our financial position, results of operations or cash flows.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*, which clarified the application of SFAS 157 in inactive markets. This FSP did not impact our financial position, results of operations or cash flows.

SFAS 157 also applies to the valuation of our pension and post-retirement plan assets. The adoption of this standard did not affect these valuations because SFAS 157 specifically excluded pension and post-retirement assets from its prescribed disclosure provisions. Accordingly, these plan assets are not included in the tabular disclosures below. However, in December 2008, the FASB issued FSP FAS 132(R)-1 — *Employers'*

Disclosures about Postretirement Benefit Plan Assets, which will, among other things, require disclosure about fair value measurements similar to those required by SFAS 157. This FSP will impact our annual disclosure requirements beginning in fiscal 2010.

In April 2009, the FASB issued FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly.* This FSP provides further guidance for estimating fair value in accordance with SFAS 157 when there has been a significant decrease in market activity for a financial asset and also identifies circumstances that indicate a transaction is not orderly. The adoption of this FSP did not impact our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*. This FSP requires companies to disclose the fair value of financial instruments for which it is practicable to estimate the value and the methods and significant assumptions used to estimate the fair value. We have adopted the disclosure requirements of this FSP, which are presented below.

Determining Fair Value

SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under SFAS 157. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Recent adverse developments in the global financial and credit markets have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. A continued tightening of the credit markets could cause more of our counterparties to fail to perform. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities.

Level 2 — Pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable.

Level 3 — Generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. Currently, we have no assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009. As required under SFAS 157, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[1]	June 30, 2009
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,233	$ —	$ —	$ 1,233
Natural gas marketing segment	40,494	73,149	—	(73,722)	39,921
Total financial instruments	40,494	74,382	—	(73,722)	41,154
Hedged portion of gas stored underground					
Natural gas marketing segment	79,604	—	—	—	79,604
Pipeline, storage and other segment[2]	7,023	—	—	—	7,023
Total gas stored underground	86,627	—	—	—	86,627
Available-for-sale securities	38,856	—	—	—	38,856
Total assets	$165,977	$74,382	$ —	$(73,722)	$166,637
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$23,261	$ —	$ —	$ 23,261
Natural gas marketing segment	72,410	22,789	—	(94,336)	863
Total liabilities	$ 72,410	$46,050	$ —	$(94,336)	$ 24,124

(1) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and FSP FIN 39-1. In addition, as of June 30, 2009, we had $20.6 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $0.1 million was used to offset financial instruments in a liability position. The remaining $20.5 million has been reflected as a financial instrument asset.

(2) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Other Fair Value Measures

In addition to the financial instruments above, we have several nonfinancial assets and liabilities subject to fair value measures. These assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable, debt, asset retirement obligations and pension and post-retirement plan assets. As noted above, fair value disclosures for asset retirement obligations and pension and post-retirement plan assets are not currently effective for us. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities. The fair value of our debt is determined using a discounted cash flow analysis based upon borrowing rates currently available to us, the remaining average maturities and our credit rating. The following table presents the carrying value and fair value of our debt as of June 30, 2009:

	June 30, 2009
	(In thousands)
Carrying Amount	$2,172,893
Fair Value	$2,068,388

The fair value as of June 30, 2009 was calculated utilizing discount rates ranging from 3.5 percent to 7.2 percent, remaining average maturities ranging from one to 26 years, and a credit adjustment of 2.9 percent.

5. Debt

Long-term debt

Long-term debt at June 30, 2009 and September 30, 2008 consisted of the following:

	June 30, 2009	September 30, 2008
	(In thousands)	
Unsecured 4.00% Senior Notes, redeemed April 2009	$ —	$ 400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	—
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 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
Other term notes due in installments through 2013	590	1,309
Total long-term debt	2,172,893	2,123,612
Less:		
Original issue discount on unsecured senior notes and debentures	(3,367)	(3,035)
Current maturities	(131)	(785)
	$2,169,395	$2,119,792

On March 26, 2009, we closed our Senior Notes Offering. The effective interest rate on these notes is 8.69 percent, after giving effect to the settlement of the $450 million Treasury lock discussed in Note 3. Most of the net proceeds of approximately $446 million were used to redeem our $400 million 4.00% unsecured senior notes on April 30, 2009, prior to their October 2009 maturity. In connection with the repayment of the $400 million 4.00% unsecured senior notes, we paid a $6.6 million call premium in accordance with the terms of the senior notes and accrued interest of approximately $0.6 million. The remaining net proceeds were used for general corporate purposes.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.3 billion of working capital funding. At June 30, 2009, there was no short-term debt outstanding. At September 30, 2008, there was $350.5 million of short-term debt outstanding, comprised of $330.5 million outstanding under our bank credit facilities and $20.0 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed primarily through a $566.7 million commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $800 million of working capital funding. The first facility is a five-year unsecured facility, expiring December 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At the time this credit facility was established, borrowings under this facility were limited to $600 million. However, in September 2008, the limit on borrowings was effectively reduced to $566.7 million after one lender with a 5.55% share of the commitments ceased funding under the facility. On March 30, 2009, the credit facility was amended to reflect this reduction. At June 30, 2009, there were no borrowings under this facility and $566.7 million was available.

The second facility is a $212.5 million unsecured 364-day facility expiring October 2009, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.25 percent to 2.50 percent, based on the Company's credit ratings. At June 30, 2009, there were no borrowings outstanding under this facility.

The third facility was an $18 million unsecured facility that bore interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility expired on March 31, 2009 and was replaced with a $25 million unsecured facility effective April 1, 2009 that bears interest at a daily negotiated rate. At June 30, 2009, there were no borrowings outstanding under this facility.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2009, our total-debt-to-

total-capitalization ratio, as defined, was 52 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $200 million intercompany revolving credit facility with AEH. Through December 31, 2008, this facility bore interest at the one-month LIBOR rate plus 0.20 percent. In January 2009, this facility was replaced with a new $200 million 364 day-facility that bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved the new facility through December 31, 2009. There was $40.3 million outstanding under this facility at June 30, 2009.

Nonregulated Operations

On December 30, 2008, AEM and the participating banks amended and restated AEM's former uncommitted credit facility, primarily to convert the $580 million uncommitted demand credit facility to a 364-day $375 million committed revolving credit facility and extend it to December 29, 2009. Effective April 1, 2009, the borrowing base was increased to $450 million through the exercise of an accordion feature in the facility.

The amended facility also adds a swing line loan feature; adjusts the interest rate on borrowings as discussed below and increases the fees paid to reflect the facility's conversion to a committed facility and current credit market conditions. The swing line loan feature allows AEM to borrow, on a same day basis, an amount ranging from $17 million to $27 million based on the terms of an election within the agreement.

AEM uses this facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest federal funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a one-month interest period) as in effect from time to time; and (d) the "cost of funds" rate based on an average of interest rates reported by one or more of the lenders to the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; and (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 2.250 percent to 2.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At June 30, 2009, there were no borrowings outstanding under this credit facility. However, at June 30, 2009, AEM letters of credit totaling $24.0 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 $100.6 million at June 30, 2009.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At June 30, 2009, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.86 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $75 million to $112.5 million. As defined in the financial covenants, at June 30, 2009, AEM's net working capital was $195.5 million and its tangible net worth was $210.5 million.

To supplement borrowings under this facility, through December 31, 2008, AEM had a $200 million intercompany demand credit facility with AEH, which bore interest at the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Amounts outstanding under this facility are subordinated to AEM's committed credit facility. This facility was replaced with another $200 million 364-day facility in January 2009 with no material changes to its terms except for the rate of interest, which is the greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. There were no borrowings outstanding under this facility at June 30, 2009.

Finally, through December 31, 2008, AEH had a $200 million intercompany demand credit facility with AEC, which bore interest at the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. This facility was replaced with another $200 million 364-day facility in January 2009 with no material changes to its terms except for the rate of interest, which is the greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved the new facility through December 31, 2009. There were no borrowings outstanding under this facility at June 30, 2009.

Shelf Registration

On March 23, 2009, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $450 million of capacity carried over from our prior shelf registration statement filed with the SEC in December 2006.

As of June 30, 2009, we had $450 million of availability remaining under the registration statement after completing our Senior Notes Offering. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $300 million of equity securities and $150 million of subordinated debt securities.

Debt Covenants

In addition to the financial covenants described above, our debt instruments contain various covenants that are usual and customary for debt instruments of these types.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of June 30, 2009. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

Basic and diluted earnings per share for the three and nine months ended June 30, 2009 and 2008 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands, except per share amounts)			
Net income (loss)	$ 1,964	$ (6,588)	$206,930	$178,749
Denominator for basic income per share — weighted average common shares	91,338	89,648	90,940	89,281
Effect of dilutive securities:				
Restricted and other shares	616	—	611	557
Stock options	48	—	39	99
Denominator for diluted income per share — weighted average common shares	92,002	89,648	91,590	89,937
Income (loss) per share — basic	$ 0.02	$ (0.07)	$ 2.28	$ 2.00
Income (loss) per share — diluted	$ 0.02	$ (0.07)	$ 2.26	$ 1.99

There were approximately 33,000 and 132,000 out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2009.

There were approximately 557,000 restricted and other shares and approximately 99,000 stock options that were excluded from the calculation of diluted earnings per share for the three months ended June 30, 2008 as their inclusion in the computation would be anti-dilutive. There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2008 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, 2009 and 2008 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,703	$ 3,879	$2,946	$3,342
Interest cost	7,554	6,736	3,520	2,912
Expected return on assets	(6,238)	(6,311)	(573)	(715)
Amortization of transition asset	—	—	378	377
Amortization of prior service cost	(183)	(171)	—	—
Amortization of actuarial loss	955	1,926	—	—
Net periodic pension cost	$ 5,791	$ 6,059	$6,271	$5,916

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 11,109	$ 11,635	$ 8,838	$10,024
Interest cost	22,662	20,208	10,560	8,736
Expected return on assets	(18,714)	(18,932)	(1,719)	(2,145)
Amortization of transition asset	—	—	1,134	1,133
Amortization of prior service cost	(549)	(513)	—	—
Amortization of actuarial loss	2,865	5,778	—	—
Net periodic pension cost	$ 17,373	$ 18,176	$18,813	$17,748

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2009 and 2008 are as follows:

	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
Discount rate	7.57%	6.30%	7.57%	6.30%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2009. In June 2009, we contributed $21 million in cash to our pension plans to achieve a desired level of funding while maximizing the tax deductibility of this payment.

We contributed $8.2 million to our other post-retirement benefit plans during the nine months ended June 30, 2009. We expect to contribute a total of approximately $11 million to these plans during fiscal 2009.

In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments*. This FSP amends the other-than-temporary impairment guidance for debt securities and expands the presentation and disclosure of other-than-temporary impairments on debt and equity securities in interim and annual financial statements. This FSP does not amend existing recognition and measurement guidance related to other-than-temporary impairments of equity securities.

For our Supplemental Executive Benefit Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of June 30, 2009:				
Domestic equity mutual funds	$25,824	$ 286	$ —	$26,110
Foreign equity mutual funds	4,047	—	—	4,047
Money market funds	8,699	—	—	8,699
	$38,570	$ 286	$ —	$38,856
As of September 30, 2008:				
Domestic equity mutual funds	$31,041	$1,625	$(394)	$32,272
Foreign equity mutual funds	5,309	359	—	5,668
	$36,350	$1,984	$(394)	$37,940

The following table presents interest and dividends on available-for-sale securities for the three and nine months ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Interest	$ 8	$ —	$ 8	$ —
Dividends	184	190	1,607	2,032
Total interest and dividends	$192	$190	$1,615	$2,032

The following table presents realized gains and losses on available-for-sale securities for the three and nine months ended June 30, 2009 and 2008. The gross realized investment losses exclude losses from other-than-temporary impairment:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Gross realized investment gains	$—	$51	$ —	$97
Gross realized investment losses	—	(2)	(129)	(3)
Net realized gains (losses)	$—	$49	$(129)	$94

Due to the recent deterioration of the financial markets and the uncertainty of a full recovery of these investments given the current economic environment, we have recorded a $3.3 million and $5.4 million noncash charge to impair certain available-for-sale investments during the three and nine months ended June 30, 2009. As a result of these impairments, at June 30, 2009, we did not maintain any investments that are in an unrealized loss position.

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 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30,

2008, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2009. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2009, AEM was committed to purchase 83.0 Bcf within one year and 25.4 Bcf within one to three years under indexed contracts. AEM is committed to purchase 2.9 Bcf within one year under fixed price contracts with prices ranging from $3.15 to $7.68 per Mcf. Purchases under these contracts totaled $256.0 million and $842.1 million for the three months ended June 30, 2009 and 2008 and $1,215.0 million and $2,274.4 million for the nine months ended June 30, 2009 and 2008.

Our natural gas distribution divisions, except for our 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 this service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of June 30, 2009 are as follows (in thousands):

2009	$ 20,256
2010	120,481
2011	5,658
2012	7,302
2013	7,711
Thereafter	2,614
	$164,022

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

After responding to two sets of data requests received from the Commission, the Commission agreed to allow us to conduct our own internal investigation into compliance with the Commission's rules. We have completed our internal investigation and submitted the results to the Commission. During our investigation, we identified certain transactions that could possibly be considered non-compliant, and we continue to fully

cooperate with the Commission as we work to resolve this matter. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

As of June 30, 2009, rate cases were in progress in our City of Dallas and Virginia service areas and annual rate filing mechanisms were in progress in our City of Dallas and Amarillo service areas. These regulatory proceedings are discussed in further detail in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. During the nine months ended June 30, 2009, there were no material changes in our concentration of credit risk.

10. Segment Information

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

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local distribution companies and industrial customers primarily in the Midwest and Southeast. Additionally, we provide natural gas transportation and storage services to certain of our natural gas distribution operations and to third parties.

We operate the Company through the following four segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment,* which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division.
- The *natural gas marketing segment,* which includes a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment,* which includes our nonregulated natural gas transmission and storage services.

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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2008. 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, 2009 and 2008 by segment are presented in the following tables:

	Three Months Ended June 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$386,774	$29,558	$358,458	$5,985	$ —	$780,775
Intersegment revenues	211	19,787	95,046	2,241	(117,285)	—
	386,985	49,345	453,504	8,226	(117,285)	780,775
Purchased gas cost	195,303	—	438,482	4,212	(116,862)	521,135
Gross profit	191,682	49,345	15,022	4,014	(423)	259,640
Operating expenses						
Operation and maintenance	89,534	13,784	6,445	1,641	(509)	110,895
Depreciation and amortization	47,928	5,066	392	795	—	54,181
Taxes, other than income	44,014	2,569	628	366	—	47,577
Asset impairments	2,823	370	90	21	—	3,304
Total operating expenses	184,299	21,789	7,555	2,823	(509)	215,957
Operating income	7,383	27,556	7,467	1,191	86	43,683
Miscellaneous income	2,167	615	71	2,319	(3,953)	1,219
Interest charges	32,798	8,152	4,020	408	(3,867)	41,511
Income (loss) before income taxes	(23,248)	20,019	3,518	3,102	—	3,391
Income tax expense (benefit)	(8,307)	7,065	1,419	1,250	—	1,427
Net income (loss)	$ (14,941)	$12,954	$ 2,099	$1,852	$ —	$ 1,964
Capital expenditures	$ 86,861	$28,216	$ 82	$5,837	$ —	$120,996

	Three Months Ended June 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$676,418	$27,321	$ 933,931	$1,475	$ —	$1,639,145
Intersegment revenues	221	18,965	255,791	2,405	(277,382)	—
	676,639	46,286	1,189,722	3,880	(277,382)	1,639,145
Purchased gas cost	476,711	—	1,192,353	706	(276,847)	1,392,923
Gross profit	199,928	46,286	(2,631)	3,174	(535)	246,222
Operating expenses						
Operation and maintenance	95,853	17,042	4,433	1,115	(621)	117,822
Depreciation and amortization	44,737	4,860	381	378	—	50,356
Taxes, other than income	54,141	2,493	391	310	—	57,335
Total operating expenses	194,731	24,395	5,205	1,803	(621)	225,513
Operating income (loss)	5,197	21,891	(7,836)	1,371	86	20,709
Miscellaneous income	3,508	550	377	2,273	(5,108)	1,600
Interest charges	28,504	6,606	2,850	532	(5,022)	33,470
Income (loss) before income taxes	(19,799)	15,835	(10,309)	3,112	—	(11,161)
Income tax expense (benefit)	(7,421)	5,570	(3,995)	1,273	—	(4,573)
Net income (loss)	$ (12,378)	$10,265	$ (6,314)	$1,839	$ —	$ (6,588)
Capital expenditures	$ 92,856	$18,252	$ 132	$2,916	$ —	$ 114,156

	Nine Months Ended June 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,672,742	$ 91,877	$1,524,438	$29,456	$ —	$4,318,513
Intersegment revenues	631	71,384	425,219	7,490	(504,724)	—
	2,673,373	163,261	1,949,657	36,946	(504,724)	4,318,513
Purchased gas cost	1,816,227	—	1,881,068	9,771	(503,456)	3,203,610
Gross profit	857,146	163,261	68,589	27,175	(1,268)	1,114,903
Operating expenses						
Operation and maintenance	276,462	58,448	27,228	4,700	(1,526)	365,312
Depreciation and amortization	142,608	15,027	1,189	1,933	—	160,757
Taxes, other than income	139,861	7,929	1,667	571	—	150,028
Asset impairments	4,599	602	146	35	—	5,382
Total operating expenses	563,530	82,006	30,230	7,239	(1,526)	681,479
Operating income	293,616	81,255	38,359	19,936	258	433,424
Miscellaneous income (expense)	6,123	1,713	490	6,540	(15,513)	(647)
Interest charges	94,506	23,580	11,383	1,821	(15,255)	116,035
Income before income taxes	205,233	59,388	27,466	24,655	—	316,742
Income tax expense	68,465	19,308	11,444	10,595	—	109,812
Net income	$ 136,768	$ 40,080	$ 16,022	$14,060	$ —	$ 206,930
Capital expenditures	$ 260,482	$ 61,579	$ 199	$20,066	$ —	$ 342,326

	Nine Months Ended June 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$3,126,083	$ 72,588	$2,568,643	$13,326	$ —	$5,780,640
Intersegment revenues	589	70,184	590,449	7,303	(668,525)	—
	3,126,672	142,772	3,159,092	20,629	(668,525)	5,780,640
Purchased gas cost	2,296,020	—	3,099,428	1,773	(666,835)	4,730,386
Gross profit	830,652	142,772	59,664	18,856	(1,690)	1,050,254
Operating expenses						
Operation and maintenance	291,678	47,560	17,835	3,939	(1,948)	359,064
Depreciation and amortization	130,699	14,683	1,142	1,135	—	147,659
Taxes, other than income	142,063	6,322	3,798	987	—	153,170
Total operating expenses	564,440	68,565	22,775	6,061	(1,948)	659,893
Operating income	266,212	74,207	36,889	12,795	258	390,361
Miscellaneous income	7,654	933	1,775	6,243	(13,631)	2,974
Interest charges	88,802	20,453	6,166	1,755	(13,373)	103,803
Income before income taxes	185,064	54,687	32,498	17,283	—	289,532
Income tax expense	71,622	19,351	12,933	6,877	—	110,783
Net income	$ 113,442	$ 35,336	$ 19,565	$10,406	$ —	$ 178,749
Capital expenditures	$ 266,840	$ 40,334	$ 201	$ 5,503	$ —	$ 312,878

Balance sheet information at June 30, 2009 and September 30, 2008 by segment is presented in the following tables:

	June 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,625,656	$631,136	$ 7,232	$ 75,340	$ —	$4,339,364
Investment in subsidiaries	526,941	—	(2,096)	—	(524,845)	—
Current assets						
Cash and cash equivalents	39,276	—	76,111	10,348	—	125,735
Assets from risk management activities	1,233	—	30,696	3,835	(4,510)	31,254
Other current assets	416,144	16,481	211,197	55,510	(60,309)	639,023
Intercompany receivables	507,278	—	—	146,140	(653,418)	—
Total current assets	963,931	16,481	318,004	215,833	(718,237)	796,012
Intangible assets	—	—	1,617	—	—	1,617
Goodwill	569,920	132,367	24,282	10,429	—	736,998
Noncurrent assets from risk management activities	—	—	9,900	—	—	9,900
Deferred charges and other assets	181,945	9,959	1,045	19,190	—	212,139
	$5,868,393	$789,943	$359,984	$320,792	$(1,243,082)	$6,096,030
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,191,520	$170,224	$101,997	$254,720	$ (526,941)	$2,191,520
Long-term debt	2,168,937	—	—	458	—	2,169,395
Total capitalization	4,360,457	170,224	101,997	255,178	(526,941)	4,360,915
Current liabilities						
Current maturities of long-term debt	—	—	—	131	—	131
Short-term debt	40,340	—	—	—	(40,340)	—
Liabilities from risk management activities	22,945	—	4,668	705	(4,510)	23,808
Other current liabilities	427,859	8,270	151,717	50,274	(17,760)	620,360
Intercompany payables	—	530,513	122,905	—	(653,418)	—
Total current liabilities	491,144	538,783	279,290	51,110	(716,028)	644,299
Deferred income taxes	444,621	76,837	(21,955)	11,511	(113)	510,901
Noncurrent liabilities from risk management activities	316	—	—	—	—	316
Regulatory cost of removal obligation	322,529	—	—	—	—	322,529
Deferred credits and other liabilities	249,326	4,099	652	2,993	—	257,070
	$5,868,393	$789,943	$359,984	$320,792	$(1,243,082)	$6,096,030

	September 30, 2008					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,483,556	$585,160	$ 7,520	$ 60,623	$ —	$4,136,859
Investment in subsidiaries	463,158	—	(2,096)	—	(461,062)	—
Current assets						
Cash and cash equivalents	30,878	—	9,120	6,719	—	46,717
Assets from risk management activities	—	—	69,008	20,239	(20,956)	68,291
Other current assets	774,933	18,396	411,648	56,791	(91,672)	1,170,096
Intercompany receivables	578,833	—	—	135,795	(714,628)	—
Total current assets	1,384,644	18,396	489,776	219,544	(827,256)	1,285,104
Intangible assets	—	—	2,088	—	—	2,088
Goodwill	569,920	132,367	24,282	10,429	—	736,998
Noncurrent assets from risk management activities	—	—	5,473	—	—	5,473
Deferred charges and other assets	195,985	11,212	1,182	11,798	—	220,177
	$6,097,263	$747,135	$528,225	$302,394	$(1,288,318)	$6,386,699
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,052,492	$130,144	$114,559	$218,455	$ (463,158)	$2,052,492
Long-term debt	2,119,267	—	—	525	—	2,119,792
Total capitalization	4,171,759	130,144	114,559	218,980	(463,158)	4,172,284
Current liabilities						
Current maturities of long-term debt	—	—	—	785	—	785
Short-term debt	385,592	—	6,500	—	(41,550)	350,542
Liabilities from risk management activities	58,566	—	20,688	616	(20,956)	58,914
Other current liabilities	538,777	7,053	236,217	62,796	(47,997)	796,846
Intercompany payables	—	543,384	171,244	—	(714,628)	—
Total current liabilities	982,935	550,437	434,649	64,197	(825,131)	1,207,087
Deferred income taxes	384,860	62,720	(21,936)	15,687	(29)	441,302
Noncurrent liabilities from risk management activities	5,111	—	258	—	—	5,369
Regulatory cost of removal obligation	298,645	—	—	—	—	298,645
Deferred credits and other liabilities	253,953	3,834	695	3,530	—	262,012
	$6,097,263	$747,135	$528,225	$302,394	$(1,288,318)	$6,386,699

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of June 30, 2009, the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2009 and 2008, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2009 and 2008. 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, 2008, 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 18, 2008, 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, 2008, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
August 5, 2009

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, 2008.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties, which are discussed in more detail in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008, include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of recent adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business; natural disasters, terrorist activities or other events; and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

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

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties.

We operate the Company through the following four segments:

- the *natural gas distribution segment,* which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment,* which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment,* which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment,* which is comprised of our nonregulated natural gas gathering, transmission and storage services.

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, the 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 fiscal year ended September 30, 2008 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 quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2009.

RESULTS OF OPERATIONS

During the current fiscal year, several external factors have impacted Atmos Energy, including but not limited to adverse developments in the global and financial credit markets and the unfavorable impact of the economic recession.

The tightening of the credit markets has made it more difficult and more expensive for us to access the capital markets. However, during the fiscal year, we have undertaken several steps to improve our financial position. In March 2009, we successfully completed an offering of $450 million 8.5% senior notes, and used most of the proceeds in April 2009 to redeem $400 million of senior notes that were scheduled to mature in October 2009. Additionally, we enhanced our liquidity sources in various ways. In October 2008, we replaced our former $300 million 364-day committed credit facility with a new 364-day $212.5 million committed credit facility. Additionally, we converted AEM's former $580 million uncommitted credit facility to a 364-day $375 million committed credit facility. This facility was subsequently increased to $450 million in April 2009. Finally, in April 2009 we replaced an expiring $18 million unsecured committed credit facility

with a $25 million unsecured committed credit facility. After entering into these new facilities, we currently have a total of approximately $1.3 billion available to us under four committed credit facilities. As a result of these developments and our continued successful financial performance, Standard & Poor's Corporation (S&P) upgraded our credit rating from BBB to BBB+ in December 2008 and Moody's Investors Service (Moody's) upgraded the credit rating on our senior long-term debt from Baa3 to Baa2 and our commercial paper from P-3 to P-2 in May 2009. These ratings upgrades should improve our ability to access the short-term capital markets to satisfy our liquidity requirements on more economical terms in the future.

Challenging economic times have also impacted most of our business segments. The impact of the economic downturn is most apparent in a general decline in throughput. Our natural gas distribution segment has experienced a year-over-year four percent decrease in consolidated throughput, primarily associated with lower residential, commercial and industrial consumption. Declines in the demand for natural gas as a result of idle production and plant closures have contributed to a seven percent year-over-year decrease in consolidated throughput in our regulated transmission and storage segment and a five percent year-over-year decrease in consolidated sales volumes in our natural gas marketing segment. However, recent improvements in rate design in our natural gas distribution segment and the ability to earn higher per-unit margins in our regulated transmission and storage and natural gas marketing segments has more than offset the decline in throughput and sales volumes. Additionally, reduced demand for natural gas has resulted in lower natural gas prices, which has contributed significantly to the increase in our operating cash flow from $417 million for the nine months ended June 30, 2008 to $825 million for the nine months ended June 30, 2009.

The seasonality of our distribution business typically results in a loss in our fiscal third quarter. However, we reported net income of $2.0 million, or $0.02 per diluted share for the three months ended June 30, 2009 compared with a net loss of $6.6 million, or $0.07 per diluted share in the prior-year quarter. The quarter-over-quarter improvement reflects higher gross profit in our regulated transmission and storage and natural gas marketing segments combined with lower consolidated operation and maintenance expense, which more than offset lower natural gas distribution margins and a $3.3 million charge to impair certain available-for-sale investments.

For the first nine months of fiscal 2009, net income increased 16 percent to $206.9 million, or $2.26 per diluted share. Regulated operations contributed 85 percent of our net income during this period with our nonregulated operations contributing the remaining 15 percent. Results for the nine months ended June 30, 2009 include the favorable impact of a one-time tax benefit of $11.3 million, or $0.12 per diluted share and the unfavorable impact of a $5.4 million charge, or $0.04 per diluted share, to impair certain available-for-sale investments. Additionally, results for the nine-month period ended June 30, 2009 reflect increased gross profit across all of our business segments, partially offset by higher depreciation expense, pipeline maintenance and employee costs and interest expense.

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands, except per share data)			
Operating revenues	$780,775	$1,639,145	$4,318,513	$5,780,640
Gross profit	259,640	246,222	1,114,903	1,050,254
Operating expenses	215,957	225,513	681,479	659,893
Operating income	43,683	20,709	433,424	390,361
Miscellaneous income (expense)	1,219	1,600	(647)	2,974
Interest charges	41,511	33,470	116,035	103,803
Income (loss) before income taxes	3,391	(11,161)	316,742	289,532
Income tax expense (benefit)	1,427	(4,573)	109,812	110,783
Net income (loss)	$ 1,964	$ (6,588)	$ 206,930	$ 178,749
Diluted net income (loss) per share	$ 0.02	$ (0.07)	$ 2.26	$ 1.99

Our consolidated net income (loss) during the three and nine months ended June 30, 2009 and 2008 was earned in each of our business segments as follows:

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Natural gas distribution segment	$(14,941)	$(12,378)	$(2,563)
Regulated transmission and storage segment	12,954	10,265	2,689
Natural gas marketing segment	2,099	(6,314)	8,413
Pipeline, storage and other segment	1,852	1,839	13
Net income (loss)	$ 1,964	$ (6,588)	$ 8,552

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Natural gas distribution segment	$136,768	$113,442	$23,326
Regulated transmission and storage segment	40,080	35,336	4,744
Natural gas marketing segment	16,022	19,565	(3,543)
Pipeline, storage and other segment	14,060	10,406	3,654
Net income	$206,930	$178,749	$28,181

The following tables segregate our consolidated net income (loss) and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$(1,987)	$(2,113)	$ 126
Nonregulated operations	3,951	(4,475)	8,426
Consolidated net income (loss)	$ 1,964	$(6,588)	$8,552
Diluted EPS from regulated operations	$ (0.02)	$ (0.02)	$ —
Diluted EPS from nonregulated operations	0.04	(0.05)	0.09
Consolidated diluted EPS	$ 0.02	$ (0.07)	$ 0.09

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$176,848	$148,778	$28,070
Nonregulated operations	30,082	29,971	111
Consolidated net income	$206,930	$178,749	$28,181
Diluted EPS from regulated operations	$ 1.93	$ 1.66	$ 0.27
Diluted EPS from nonregulated operations	0.33	0.33	—
Consolidated diluted EPS	$ 2.26	$ 1.99	$ 0.27

Three Months Ended June 30, 2009 compared with Three Months Ended June 30, 2008

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

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

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues.

Gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact of these timing differences is generally offset within operating income. Prior to January 1, 2009, timing differences existed between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. These timing differences had a significant temporary effect on operating income in periods with volatile gas prices, particularly in our Mid-Tex Division. Beginning January 1, 2009, changes in our franchise fee agreements in our Mid-Tex Division became effective which should significantly reduce the impact of this timing difference on a prospective basis. However, this timing difference will still be present for gross receipts taxes.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2009 and 2008 are presented below.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$191,682	$199,928	$ (8,246)
Operating expenses	184,299	194,731	(10,432)
Operating income	7,383	5,197	2,186
Miscellaneous income	2,167	3,508	(1,341)
Interest charges	32,798	28,504	4,294
Loss before income taxes	(23,248)	(19,799)	(3,449)
Income tax benefit	(8,307)	(7,421)	(886)
Net loss	$ (14,941)	$ (12,378)	$ (2,563)
Consolidated natural gas distribution sales volumes — MMcf	40,081	41,357	(1,276)
Consolidated natural gas distribution transportation volumes — MMcf	29,597	32,126	(2,529)
Total consolidated natural gas distribution throughput — MMcf	69,678	73,483	(3,805)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.43	$ 0.03
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.87	$ 11.53	$ (6.66)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the three months ended June 30, 2009 and 2008. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Mid-Tex	$(3,598)	$(3,043)	$ (555)
Kentucky/Mid-States	2,931	5,757	(2,826)
Louisiana	5,459	5,086	373
West Texas	1,010	(563)	1,573
Mississippi	(585)	(946)	361
Colorado-Kansas	1,247	542	705
Other	919	(1,636)	2,555
Total	$ 7,383	$ 5,197	$ 2,186

The $8.2 million decrease in natural gas distribution gross profit primarily reflects a net $5.4 million decrease in margins in the Mid-Tex Division. This reduction in margins was primarily due to rate design changes implemented in November 2008 that decreased the monthly base charge and increased the volumetric charge for most of the Mid-Tex Division's customers. This change results in higher gross profit during the winter heating season and lower gross profit in the summer months. The current year period also reflects a $3.3 million increase in rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas. The

decrease in gross profit also reflects a $3.5 million decrease as a result of a five percent decrease in distribution throughput, primarily associated with lower residential, commercial and industrial consumption. Finally, service revenue and late charges, which are based on the customer's outstanding balance, decreased $1.3 million due to the lower cost of natural gas in the current-year period.

Partially offsetting these decreases was an increase of approximately $1.3 million in revenue-related taxes in the current-year quarter compared to the prior-year quarter primarily due to the timing change in franchise fees in our Mid-Tex Division. This increase was combined with a $9.5 million quarter-over-quarter decrease in the associated franchise and state gross receipts tax expense recorded as a component of taxes, other than income, resulting in a $10.8 million increase in operating income when compared with the prior-year quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income, and asset impairments decreased $10.4 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $4.9 million, primarily due to lower legal and other administrative costs. These decreases were partially offset by a $2.8 million noncash charge to impair certain available-for-sale investments as the Company believed the fair value of these investments would not recover within a reasonable period of time.

Depreciation and amortization expense increased $3.2 million for the third quarter of fiscal 2009 compared with third quarter of fiscal 2008. The increase primarily was attributable to additional assets placed in service during the current-year period.

Interest charges allocated to the natural gas distribution segment increased $4.3 million due to the effect of the Company's March 2009 issuance of $450 million 8.50% senior notes to repay $400 million 4.00% senior notes in April 2009.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the nine months ended June 30, 2009 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's final ruling.

Annual Rate Filing Mechanisms

In March 2009, the Mid-Tex Division filed its second Rate Review Mechanism (RRM) with the Settled Cities. The filing requested an increase in annual operating income of $9.7 million for the Settled Cities. The Mid-Tex Division and representatives of the Settled Cities reached an agreement to increase annual operating income by $2.0 million, which will be implemented in rates beginning in August 2009. Beginning in November 2008, rates were implemented from our first RRM filing with the Settled Cities, which resulted in an increase in annual operating income on a system-wide basis of approximately $27.3 million. The impact to the Mid-Tex Division for the Settled Cities was approximately $21.8 million.

In April 2009, the West Texas Division filed its second RRM with the West Texas Cities. The filing requested an increase in annual operating income of $11.1 million. The West Texas Division and representatives of the West Texas Cities reached an agreement to increase annual operating income $7.8 million, which will be implemented in rates beginning in August 2009. Beginning in November 2008, rates were implemented from our first RRM with the West Texas Cities, which resulted in an increase in operating income of $4.5 million, of which $3.9 million is being collected over a 9½ month period.

In April 2009, the City of Lubbock approved an RRM tariff similar to the RRM tariff utilized by the West Texas Cities. The West Texas Division filed its first RRM with the City of Lubbock on April 15, 2009. The filing requested an increase in annual operating income of $3.5 million. The City of Lubbock is currently reviewing the filing and a final determination is expected in October 2009.

In June 2009, the City of Amarillo approved an RRM tariff similar to the RRM tariff utilized by the West Texas Cities. The West Texas Division filed its first RRM with the City of Amarillo on June 17, 2009. The filing requested an annual increase in operating income of $2.3 million. The City of Amarillo is currently reviewing the filing and a final determination is expected in October 2009.

In December 2008, the Louisiana Division filed its TransLa annual rate stabilization clause with the Louisiana Public Service Commission (LPSC) for the test year ended September 30, 2008. The filing resulted in an annual increase in operating income of $0.6 million and was implemented in April 2009.

In April 2009, the Louisiana Division filed its LGS annual rate stabilization clause with the LPSC. The filing was for the test year ended December 31, 2008. The filing resulted in an annual increase in operating income of $3.3 million and was implemented in July 2009.

In September 2008, we filed our Mississippi stable rate filing with the Mississippi Public Service Commission (MPSC) requesting an increase in annual operating income of $3.5 million. In January 2009, we withdrew this request after we were unable to reach a mutually agreeable settlement with the MPSC.

GRIP Filings

In May 2008, the Mid-Tex Division made a GRIP filing seeking a $10.3 million increase on a system-wide basis. However, this filing was only applicable to the City of Dallas and the Mid-Tex environs and sought a $1.8 million increase for customers in those service areas. Rates were approved for this filing in December 2008 and were implemented in January 2009. However, in April 2009, the City of Dallas challenged the legality of the implementation of the GRIP rates, which the Company is contesting in the District Courts of Dallas and Travis Counties.

In March 2009, the Mid-Tex Division made a GRIP filing seeking an $18.7 million increase on a system-wide basis. However, this filing is applicable to the City of Dallas only and seeks a $2.7 million increase for customers in the City of Dallas. The City of Dallas denied this GRIP filing in June 2009 and the Mid-Tex Division has appealed this action to the Railroad Commission of Texas (RRC).

Any rate increases granted from these GRIP filings will be in effect until such time that they are superseded by the statement of intent filed with the City of Dallas discussed below.

Rate Case Filings

In October 2008, our Kentucky/Mid-States Division filed a rate case with the Tennessee Regulatory Authority seeking an increase in annual operating income of $6.3 million. In January 2009, the Consumer Advocate and Protection Division recommended a decrease in rates of $3.7 million. In March 2009, a unanimous stipulation was filed and approved in the case. The parties agreed to an increase in annual operating income of $2.5 million with a stated return on equity of 10.3 percent. The increase in rates was implemented in April 2009.

In November 2008, the Mid-Tex Division filed a statement of intent to increase annual operating income for customers within the City of Dallas by $9.1 million. The City of Dallas suspended the filing in December 2008 and denied the increase in March 2009. The Mid-Tex Division has appealed the filing and in April 2009 we requested an increase in annual operating income of $7.5 million and concurrently filed for a statement of intent to increase annual operating income $1.3 million applicable to the Mid-Tex unincorporated areas. The City of Dallas has proposed a reduction of rates of $28.9 million to annual operating income system-wide, or approximately $5.8 million for the City of Dallas and environs customers. On August 4, 2009, the Mid-Tex Division filed a rebuttal revising the requested increase in annual operating income to $6.6 million for the City of Dallas and $1.1 million for the Mid-Tex unincorporated areas. A hearing is scheduled with the RRC in August 2009 and a final ruling is expected in November 2009. If the statement of intent applicable to the City of Dallas is approved by the RRC, the new rates implemented could supersede the City of Dallas GRIP rates discussed above.

In April 2009, the Kentucky/Mid-States Division filed an expedited rate case with the Virginia State Corporation Commission seeking an increase in annual operating income of $1.7 million. Interim rates were implemented subject to refund on May 1, 2009. The application is currently in discovery with a final determination expected in October 2009.

In July 2009, the Colorado/Kansas Division filed a rate case with the Colorado Public Service Commission seeking an increase in annual operating income of $3.8 million effective in August 2009. A procedural schedule has not been established; however the Commission is expected to suspend the filing.

Other Ratemaking Activity

In May 2007, our Mid-Tex Division filed for a 36-month gas contract review filing. This filing was mandated by prior RRC orders and related to the prudency of gas purchases made from November 2003 through October 2006, which total approximately $2.7 billion. The intervening parties recommended disallowances ranging from $58 million to $89 million. A hearing was held at the RRC in September 2008. In December 2008, a proposal for decision was issued by the Hearing Examiner recommending no gas cost disallowance. In February 2009, the RRC approved the Hearing Examiner's recommendation to disallow no gas costs.

In March 2009, the RRC established a procedural schedule to examine the 36-month gas contract review process. Briefs were filed in April 2009 and the Hearing Examiner issued a proposal for decision in June 2009 which recommended the elimination of the 36-month gas contract review process. The RRC has not taken any action on the proposed final order.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2009 and 2008 are presented below.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 19,507	$ 18,761	$ 746
Third-party transportation	24,285	22,485	1,800
Storage and park and lend services	3,137	2,387	750
Other	2,416	2,653	(237)
Gross profit	49,345	46,286	3,059
Operating expenses	21,789	24,395	(2,606)
Operating income	27,556	21,891	5,665
Miscellaneous income	615	550	65
Interest charges	8,152	6,606	1,546
Income before income taxes	20,019	15,835	4,184
Income tax expense	7,065	5,570	1,495
Net income	$ 12,954	$ 10,265	$ 2,689
Gross pipeline transportation volumes — MMcf	169,641	181,112	(11,471)
Consolidated pipeline transportation volumes — MMcf	141,556	152,450	(10,894)

The $3.1 million increase in gross profit was attributable primarily to a $3.5 million increase from higher demand-based fees. The improvement in gross profit also reflects a $1.1 million increase due to our GRIP filings. These increases were partially offset by a $0.7 million decrease arising from a seven percent decrease in city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses decreased $2.6 million primarily due to a decrease in pipeline maintenance costs during the current-year quarter.

Recent Ratemaking Developments

In February 2009, the Atmos Pipeline — Texas Division made a GRIP filing seeking an increase in annual operating income of $6.3 million. The filing was approved by the RRC and a final order was issued in April 2009.

Natural Gas Marketing Segment

Our natural gas marketing activities are conducted through Atmos Energy Marketing, LLC (AEM). AEM 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 financial instruments. 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 received for services we deliver.

Our asset optimization activities seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging 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 instruments at advantageous prices to lock in a gross

profit margin. We also seek to 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. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time.

AEM continually manages its net physical position to attempt to increase in the future the potential economic gross profit that was created when the original transaction was executed. Therefore, AEM may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEM elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to economically hedge the original financial instruments. If AEM elects to defer the withdrawal of gas, it will reset its financial instruments by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEM also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the execution of the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the three months ended June 30, 2009 and 2008 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical (spot) and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the

unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 16,598	$ 11,231	$ 5,367
Asset optimization	(14,580)	(37,551)	22,971
	2,018	(26,320)	28,338
Unrealized margins	13,004	23,689	(10,685)
Gross profit	15,022	(2,631)	17,653
Operating expenses	7,555	5,205	2,350
Operating income	7,467	(7,836)	15,303
Miscellaneous income	71	377	(306)
Interest charges	4,020	2,850	1,170
Income (loss) before income taxes	3,518	(10,309)	13,827
Income tax expense (benefit)	1,419	(3,995)	5,414
Net income (loss)	$ 2,099	$ (6,314)	$ 8,413
Gross natural gas marketing sales volumes — MMcf	103,146	103,403	(257)
Consolidated natural gas marketing sales volumes — MMcf	84,162	82,122	2,040
Net physical position (Bcf)	20.0	17.5	2.5

The $17.7 million increase in our natural gas marketing segment's gross profit was driven primarily by a $23.0 million increase in asset optimization margins. The increase was primarily the result of a decrease in losses realized on financial settlements during the current quarter when compared to the prior-year quarter. Settlements during both years were primarily related to the deferral of storage withdrawals as AEM had elected to reset the corresponding financial instruments to future periods to increase the potential gross profit it could realize from its asset optimization activities. The reduction in realized losses was caused by greater price volatility in the prior-year period which had a greater impact on the settlement of financial instruments used to hedge our physical storage.

The increase in asset optimization margins was partially offset by a $10.7 million decrease in unrealized margins. This decrease reflects lower volatility during the current quarter compared with the prior-year quarter between current cash prices used to value our physical inventory and future natural gas prices, which influence the prices used to value the financial instruments used to hedge our physical inventory.

In addition, delivered gas margins increased $5.4 million compared with the prior-year quarter largely attributable to a 48 percent increase in gross per-unit margins on similar gross sales volumes period over period as a result of greater basis opportunities in certain market areas and successful contract renewals.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments increased $2.4 million primarily due to an increase in legal and other administrative costs.

Economic Gross Profit

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before associated storage fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic gross profit, combined with the effect of the future reversal of

unrealized gains or losses currently recognized in the income statement is referred to as the potential gross profit.[1] The following table presents AEM's economic gross profit and its potential gross profit at June 30, 2009, March 31, 2009, December 31, 2008, September 30, 2008 and June 30, 2008.

Period Ending	Net Physical Position (Bcf)	Economic Gross Profit (In millions)	Associated Net Unrealized Gain (In millions)	Potential Gross Profit[1] (In millions)
June 30, 2009	20.0	$42.0	$16.7	$25.3
March 31, 2009	21.9	$33.4	$ 2.4	$31.0
December 31, 2008	16.3	$20.7	$ 4.8	$15.9
September 30, 2008	8.0	$48.5	$36.4	$12.1
June 30, 2008	17.5	$48.2	$34.3	$13.9

(1) Potential gross profit represents the increase in AEM's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include storage and other operating expenses and increased income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic gross profit or the potential gross profit will be fully realized in the future. We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides our investors a more comprehensive view of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone.

As of June 30, 2009, based upon AEM's planned inventory withdrawal schedule and associated planned settlement of financial instruments, the economic gross profit was $42.0 million. This amount will be reduced by $16.7 million of net unrealized gains recorded in the financial statements as of June 30, 2009 that will reverse when the inventory is withdrawn and the accompanying financial instruments are settled. Therefore, the potential gross profit associated with these positions was $25.3 million at June 30, 2009.

During the nine months ended June 30, 2009, AEM increased its potential gross profit by $13.2 million to $25.3 million. In the first quarter, AEM withdrew gas and substantially realized the associated potential gross profit reported as of September 30, 2008. Since that time, as a result of falling current cash prices, AEM has been deferring storage withdrawals and has been a net injector of gas into storage to increase the potential gross profit it could realize in future periods from its asset optimization activities. As a result of these activities, AEM has increased its net physical position by 12.0 Bcf since September 30, 2008. However, the captured spreads on these positions have been lower than those captured as of September 30, 2008, resulting in a lower economic gross profit compared to that time. This decrease from September 2008 to June 2009 was partially offset by lower unrealized gains associated with these positions primarily due to lower current cash prices and lower volatility between cash and future prices.

The economic gross profit is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage 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, 2009 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted. Assuming AEM fully executes its plan in place on June 30, 2009, without encountering operational or other issues, we anticipate that approximately $15.9 million of the economic gross profit as of June 30, 2009 will be recognized in fiscal 2009 with the remaining $26.1 million expected to be recognized during the first six months of fiscal 2010.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS owns and operates a 21 mile pipeline located in New Orleans, Louisiana. This pipeline is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana and for AEM, but also provides limited third party transportation services.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are asset management plans with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements.

Further, APS owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for pipeline capacity to meet customer demand during peak periods. Finally, APS manages our natural gas gathering operations, which were limited in nature as of June 30, 2009.

Results for this segment are impacted primarily by seasonal weather patterns and volatility in the natural gas markets. Additionally, this segment's results include an unrealized component as APS hedges its risk associated with its asset optimization activities.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the three months ended June 30, 2009 and 2008 are presented below.

	Three Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Asset optimization	$ 1,051	$ (484)	$1,535
Storage and transportation services	3,470	3,464	6
Other	737	592	145
Unrealized margins	(1,244)	(398)	(846)
Gross profit	4,014	3,174	840
Operating expenses	2,823	1,803	1,020
Operating income	1,191	1,371	(180)
Miscellaneous income	2,319	2,273	46
Interest charges	408	532	(124)
Income before income taxes	3,102	3,112	(10)
Income tax expense	1,250	1,273	(23)
Net income	$ 1,852	$1,839	$ 13

Gross profit from our pipeline, storage and other segment increased $0.8 million primarily due to a $1.5 million increase in asset optimization margins resulting from larger basis gains earned from utilizing controlled pipeline capacity. These increases were partially offset by a $0.8 million decrease in unrealized margins associated with our asset optimization activities due to a widening of the spreads between current cash prices and forward natural gas prices.

Operating expenses for the three months ended June 30, 2009 increased $1.0 million primarily due to increased employee costs and higher depreciation expense, which was largely attributable to additional assets placed in service during the current-year period.

Nine Months Ended June 30, 2009 compared with Nine Months Ended June 30, 2008

Natural Gas Distribution Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$857,146	$830,652	$ 26,494
Operating expenses	563,530	564,440	(910)
Operating income	293,616	266,212	27,404
Miscellaneous income	6,123	7,654	(1,531)
Interest charges	94,506	88,802	5,704
Income before income taxes	205,233	185,064	20,169
Income tax expense	68,465	71,622	(3,157)
Net income	$136,768	$113,442	$ 23,326
Consolidated natural gas distribution sales volumes — MMcf	253,087	261,692	(8,605)
Consolidated natural gas distribution transportation volumes — MMcf	98,994	105,605	(6,611)
Total consolidated natural gas distribution throughput — MMcf	352,081	367,297	(15,216)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.44	$ 0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 7.18	$ 8.77	$ (1.59)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the nine months ended June 30, 2009 and 2008. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Mid-Tex	$129,454	$119,661	$ 9,793
Kentucky/Mid-States	49,360	49,800	(440)
Louisiana	39,825	36,254	3,571
West Texas	23,829	13,332	10,497
Mississippi	24,621	23,397	1,224
Colorado-Kansas	23,471	22,766	705
Other	3,056	1,002	2,054
Total	$293,616	$266,212	$27,404

The $26.5 million increase in natural gas distribution gross profit primarily reflects a net $35.1 million increase in rates. The net increase in rates was attributable primarily to the Mid-Tex Division, which increased $22.4 million as a result of the implementation of its 2008 Rate Review Mechanism (RRM) filing with all incorporated cities in the division other than the City of Dallas (the Settled Cities) and rate adjustments for customers in the City of Dallas. The current year period also reflects a $12.7 million increase in rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas. The increase in gross profit also reflects the reversal of a $7.0 million uncollectible gas cost accrual recorded in a prior year and a $7.8 million increase attributable to a non-recurring update to our estimate for gas delivered to customers but not yet billed to reflect changes in base rates in several of our jurisdictions recorded in the fiscal first quarter. These increases in gross profit were partially offset by an $18.8 million decrease as a result of a four percent decrease in distribution throughput primarily associated with lower residential, commercial and industrial consumption and warmer weather in our Colorado service area, which does not have weather-normalized rates.

Partially offsetting these increases was a decrease of approximately $8.0 million in revenue-related taxes primarily due to lower revenues, on which the tax is calculated, in the current-year period compared to the prior-year period. This decrease, partially offset by a $2.2 million period-over-period decrease in the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income, resulted in a $5.8 million decrease in operating income when compared with the prior-year period.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income, and asset impairments decreased $0.9 million.

Operation and maintenance expense, excluding the provision for doubtful accounts, decreased $11.3 million, primarily due to lower legal, fuel and other administrative costs. These decreases were partially offset by a $4.6 million noncash charge to impair certain available-for-sale investments as the Company believed the fair value of these investments would not recover within a reasonable period of time.

Depreciation and amortization expense increased $11.9 million for the current-year period compared with nine months ended June 30, 2008. The increase primarily was attributable to additional assets placed in service during the current-year period.

Results for the prior-year period also included a $1.2 million gain on the sale of irrigation assets in our West Texas Division.

Interest charges allocated to the natural gas distribution segment increased $5.7 million primarily due to the effect of the Company's March 2009 issuance of $450 million 8.50% senior notes to repay $400 million 4.00% senior notes in April 2009. In addition, higher average short-term debt balances, interest rates and commitment fees were experienced during the current-year period compared to the prior-year period.

Results for the current-year period include a $10.5 million tax benefit associated with updating the rates used to determine our deferred taxes.

Regulated Transmission and Storage Segment

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 70,920	$ 69,409	$ 1,511
Third-party transportation	73,497	58,946	14,551
Storage and park and lend services	8,151	6,288	1,863
Other	10,693	8,129	2,564
Gross profit	163,261	142,772	20,489
Operating expenses	82,006	68,565	13,441
Operating income	81,255	74,207	7,048
Miscellaneous income	1,713	933	780
Interest charges	23,580	20,453	3,127
Income before income taxes	59,388	54,687	4,701
Income tax expense	19,308	19,351	(43)
Net income	$ 40,080	$ 35,336	$ 4,744
Gross pipeline transportation volumes — MMcf	555,169	593,452	(38,283)
Consolidated pipeline transportation volumes — MMcf	400,699	429,758	(29,059)

The $20.5 million increase in gross profit was attributable primarily to an $11.0 million increase from higher demand-based fees and a $7.5 million increase resulting from higher transportation fees on through-system deliveries due to market conditions. The improvement in gross profit also reflects a $3.8 million increase due to our GRIP filings and a $2.9 million gain on the sale of excess gas during the current-year period. These increases were partially offset by a $4.2 million decrease associated with a seven percent decrease in city-gate, electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $13.4 million primarily due to increased employee and pipeline maintenance costs.

Results for the current-year period also include a $1.7 million tax benefit associated with updating the rates used to determine our deferred taxes.

Natural Gas Marketing Segment

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 58,316	$ 55,599	$ 2,717
Asset optimization	20,286	(10,339)	30,625
	78,602	45,260	33,342
Unrealized margins	(10,013)	14,404	(24,417)
Gross profit	68,589	59,664	8,925
Operating expenses	30,230	22,775	7,455
Operating income	38,359	36,889	1,470
Miscellaneous income	490	1,775	(1,285)
Interest charges	11,383	6,166	5,217
Income before income taxes	27,466	32,498	(5,032)
Income tax expense	11,444	12,933	(1,489)
Net income	$ 16,022	$ 19,565	$ (3,543)
Gross natural gas marketing sales volumes — MMcf	336,870	348,789	(11,919)
Consolidated natural gas marketing sales volumes — MMcf	282,443	298,351	(15,908)
Net physical position (Bcf)	20.0	17.5	2.5

The $8.9 million increase in our natural gas marketing segment's gross profit was driven primarily by a $30.6 million increase in asset optimization margins. During the first quarter of fiscal 2009, AEM withdrew physical storage inventory and realized the spreads it had captured during fiscal 2008 as a result of deferring storage withdrawals and increasing the spreads associated with those physical positions. These gains were partially offset by margin losses incurred in the second and third fiscal quarters as a result of deferring storage withdrawals and injecting gas into storage. In the prior-year period, AEM deferred storage withdrawals from the first quarter into the second quarter, and recognized the storage withdrawal gains during the second quarter of fiscal 2008.

The increase in asset optimization margins was partially offset by a $24.4 million decrease in unrealized margins. This decrease reflects lower volatility during the current year compared with the prior-year period between current cash prices used to value our physical inventory and future natural gas prices, which influence the prices used to value the financial instruments used to hedge our physical inventory.

Additionally, realized delivered gas margins increased by $2.7 million. The increase was largely attributable to a nine percent increase in gross per-unit margins as a result of improved basis spreads in certain market areas where we were able to better optimize transportation assets and successful contract renewals, partially offset by a three percent decrease in gross sales volumes primarily associated with lower industrial demand due to the current economic climate.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments increased $7.5 million primarily due to an increase in legal and other administrative costs partially offset by the absence in the current year of $2.4 million related to tax matters incurred in the prior-year period.

Pipeline, Storage and Other Segment

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the nine months ended June 30, 2009 and 2008 are presented below.

	Nine Months Ended June 30		
	2009	2008	Change
	(In thousands)		
Asset optimization	$21,675	$ 5,890	$15,785
Storage and transportation services	10,097	10,487	(390)
Other	2,076	2,432	(356)
Unrealized margins	(6,673)	47	(6,720)
Gross profit	27,175	18,856	8,319
Operating expenses	7,239	6,061	1,178
Operating income	19,936	12,795	7,141
Miscellaneous income	6,540	6,243	297
Interest charges	1,821	1,755	66
Income before income taxes	24,655	17,283	7,372
Income tax expense	10,595	6,877	3,718
Net income	$14,060	$10,406	$ 3,654

Gross profit from our pipeline, storage and other segment increased $8.3 million primarily due to a $15.8 million increase in asset optimization margins as a result of larger realized gains from the settlement of financial positions associated with storage and trading activities, basis gains earned from utilizing controlled pipeline capacity and higher margins earned under asset management plans during the current-year period compared with the prior-year period. These increases were partially offset by a $6.7 million decrease in unrealized margins associated with our asset optimization activities due to a widening of the spreads between current cash prices and forward natural gas prices.

Operating expenses for the nine months ended June 30, 2009 increased $1.2 million primarily due to increased employee costs and higher depreciation expense which was largely attributable to additional assets placed in service during the current-year period.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

The primary means we use to fund our working capital needs and growth is to utilize internally generated funds and to access the commercial paper markets. Recent adverse developments in global financial and credit markets have made it more difficult and more expensive for the Company to access the short-term capital markets, including the commercial paper market, to satisfy our liquidity requirements. Consequently, during the first quarter, we experienced higher than normal borrowings under our five-year credit facility used to backstop our commercial paper program in lieu of commercial paper borrowings to fund our working capital needs. However, subsequent to the end of the first quarter, credit market conditions improved, both as to availability and interest rates, and we have been able to access the commercial paper markets on more reasonably economical terms. At June 30, 2009, there were no borrowings or commercial paper outstanding under this facility and $566.7 million was available.

On March 26, 2009, we closed our offering of $450 million of 8.50% senior notes due 2019. Most of the net proceeds of approximately $446 million were used to redeem our $400 million 4.00% unsecured senior notes on April 30, 2009, prior to their October 2009 maturity. In connection with the repayment of the $400 million 4.00% unsecured senior notes, we paid a $6.6 million call premium in accordance with the terms of the senior notes and accrued interest of approximately $0.6 million. The remaining net proceeds were used for general corporate purposes.

During the nine months ended June 30, 2009, we enhanced our liquidity sources in various ways. In October 2008, we replaced our former $300 million 364-day committed credit facility with a new facility that will allow borrowings up to $212.5 million and expires in October 2009. We are currently evaluating alternatives to replace this facility and believe we will successfully replace this facility on reasonably economical terms.

In December 2008, we converted AEM's former $580 million uncommitted credit facility to a $375 million committed credit facility that will expire in December 2009. Effective April 1, 2009, we exercised the accordion feature of this facility to increase the credit available under the facility to $450 million. In addition, we replaced our $18 million unsecured committed credit facility that expired in March 2009 with a $25 million unsecured facility effective April 1, 2009. As a result of executing these new agreements, we have a total of approximately $1.3 billion available to us under four committed credit facilities. As of June 30, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $905 million.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2009.

Cash Flows

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

Cash flows from operating activities

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

For the nine months ended June 30, 2009, we generated operating cash flow of $824.6 million from operating activities compared with $417.4 million for the nine months ended June 30, 2008. Period over period, the $407.2 million increase was attributable primarily to the favorable impact on our working capital due to the decline in natural gas prices in the current year compared to the prior-year period which increased operating cash flow by $251.1 million. The increase in operating cash flow was also positively impacted by $99.9 million due to lower cash margin requirements related to our natural gas marketing financial instruments and by $49.0 million due to the favorable timing in the recovery of gas costs during the current year. Partially offsetting these increases in operating cash flows was the $21.0 million contribution to our pension plans in the current year.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund growth projects, our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently,

expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a timely return on our investment. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution 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 being required to file a rate case.

Capital expenditures for fiscal 2009 are expected to range from $500 million to $515 million. For the nine months ended June 30, 2009, capital expenditures were $342.3 million compared with $312.9 million for the nine months ended June 30, 2008. The increase in capital spending primarily reflects spending for a nonregulated growth project and the construction of a pipeline extension in our regulated operations.

Cash flows from financing activities

For the nine months ended June 30, 2009, our financing activities used $397.2 million compared with $114.4 million in the prior-year period. Our significant financing activities for the nine months ended June 30, 2009 and 2008 are summarized as follows:

- On March 26, 2009, we issued $450 million of 8.50% senior notes due 2019. The effective interest rate of this offering, inclusive of all debt issue costs, was 8.74 percent. After giving effect to the settlement of our $450 million Treasury lock agreement on March 23, 2009, the effective rate on these senior notes was reduced to 8.69 percent. Most of the net proceeds of approximately $446 million were used to repay our $400 million unsecured 4.00% senior notes on April 30, 2009.

- During the nine months ended June 30, 2009, we decreased our borrowings by a net $366.4 million under our short-term credit facilities compared with $35.7 million in the prior-year period. The reduction in the net borrowings reflects the combination of increased cash flows and lower natural gas prices during the current year.

- We repaid $407.3 million of long-term debt during the nine months ended June 30, 2009 compared with $9.9 million during the nine months ended June 30, 2008. The increase in payments in the current year reflects the redemption of our $400 million unsecured 4.00% senior notes discussed above.

- During the nine months ended June 30, 2009, we paid $90.9 million in cash dividends compared with $87.8 million for the nine months ended June 30, 2008. The increase in dividends paid over the prior-year period reflects the increase in our dividend rate from $0.975 per share during the nine months ended June 30, 2008 to $0.99 per share during the nine months ended June 30, 2009 combined with new share issuances under our various equity plans.

- During the nine months ended June 30, 2009, we issued 0.9 million shares of common stock under our various equity plans, which generated net proceeds of $19.9 million. In addition, we issued 0.5 million shares of common stock under our 1998 Long-Term Incentive Plan.

The following table summarizes our share issuances for the nine months ended June 30, 2009 and 2008.

	Nine Months Ended June 30	
	2009	**2008**
Shares issued:		
Direct Stock Purchase Plan	319,732	294,071
Retirement Savings Plan and Trust	484,111	410,350
1998 Long-Term Incentive Plan	613,314	538,100
Outside Directors Stock-for-Fee Plan	2,294	2,399
Total shares issued	1,419,451	1,244,920

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.3 billion of working capital funding. As of June 30, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $905 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

On March 23, 2009, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance, including approximately $450 million of capacity carried over from our prior shelf registration statement filed with the SEC in December 2006. Immediately following the filing of the registration statement, we issued $450 million of 8.50% senior notes due 2019 under the registration statement. Most of the net proceeds of approximately $446 million were used to repay our $400 million unsecured 4.00% senior notes on April 30, 2009.

As of June 30, 2009, we had $450 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $300 million of equity securities and $150 million of subordinated debt securities.

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 regulated and nonregulated 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). In December 2008, S&P upgraded our senior long-term debt credit rating from BBB to BBB+ and changed our rating outlook from positive to stable. S&P cited improved financial performance and rate case decisions that have increased cash flow as the key drivers for the upgrade. In January 2009, Moody's changed our rating outlook from stable to positive. In May 2009, Moody's upgraded the credit rating on our senior long-term debt from Baa3 to Baa2 and on our commercial paper from P-3 to P-2 and changed our rating outlook from positive to stable. Moody's stated that the key drivers for the upgrade were the completion of a major debt refinancing and the Company improving its alternate liquidity resources while maintaining solid financial performance. Fitch still maintains its stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of the recent adverse global financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in

our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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, 2009. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2009, September 30, 2008 and June 30, 2008:

	June 30, 2009		September 30, 2008		June 30, 2008	
	(In thousands, except percentages)					
Short-term debt	$ —	—%	$ 350,542	7.7%	$ 113,257	2.6%
Long-term debt	2,169,526	49.7%	2,120,577	46.9%	2,120,788	48.9%
Shareholders' equity	2,191,520	50.3%	2,052,492	45.4%	2,105,407	48.5%
Total	$4,361,046	100.0%	$4,523,611	100.0%	$4,339,452	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 49.7 percent at June 30, 2009, 54.6 percent at September 30, 2008 and 51.5 percent at June 30, 2008. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and access to the equity capital markets.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2009.

In February 2008, Atmos Pipeline and Storage, LLC announced plans to construct and operate a salt-cavern gas storage project in Franklin Parish, Louisiana. The project, located near several large interstate pipelines, includes the development of three 5 billion cubic feet (Bcf) caverns for a total of 15 Bcf of working gas storage, with six-turn injection and withdrawal capacity. Testing of the salt core samples was completed in March 2009 which showed favorable conditions for development. In June 2009, we received our 7C certification from the Federal Energy Regulatory Commission (FERC) to construct and operate the project and expect approval of this request in June 2009. Finally, we have engaged the services of an investment bank to assist us in determining the optimal ownership and/or development alternatives for this project, which is still in process.

Risk Management Activities

We conduct risk management activities through our natural gas distribution, natural gas marketing and pipeline, storage and other segments. In our natural gas distribution segment, we use a combination of physical

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 and pipeline, storage and other segments, 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and nine months ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$(21,863)	$ 9,505	$ (63,677)	$(21,053)
Contracts realized/settled	(844)	339	(101,840)	(26,971)
Fair value of new contracts	(885)	5,675	(4,891)	5,395
Other changes in value	1,564	21,847	148,380	79,995
Fair value of contracts at end of period	$(22,028)	$37,366	$ (22,028)	$ 37,366

The fair value of our natural gas distribution segment's financial instruments at June 30, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2009				
	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	$(21,712)	$(316)	$—	$—	$(22,028)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(21,712)	$(316)	$—	$—	$(22,028)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the three and nine months ended June 30, 2009 and 2008:

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
	(In thousands)			
Fair value of contracts at beginning of period	$(32,646)	$(22,975)	$ 16,542	$ 26,808
Contracts realized/settled	42,535	30,185	29,260	(11,071)
Fair value of new contracts	—	—	—	—
Other changes in value	8,555	(50,182)	(27,358)	(58,709)
Fair value of contracts at end of period	18,444	(42,972)	18,444	(42,972)
Netting of cash collateral	20,614	62,152	20,614	62,152
Cash collateral and fair value of contracts at period end	$ 39,058	$ 19,180	$ 39,058	$ 19,180

The fair value of our natural gas marketing segment's financial instruments at June 30, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2009				
	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	$8,544	$9,900	$—	$—	$18,444
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$8,544	$9,900	$—	$—	$18,444

Pension and Postretirement Benefits Obligations

Effective October 1, 2008, the Company adopted the requirement under SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R),* that the measurement date used to determine our projected benefit and postretirement obligations and net periodic pension and postretirement costs must correspond to a fiscal year end. In accordance with the transition rules, the impact of changing the measurement date from June 30, 2008 to September 30, 2008 decreased retained earnings by $7.8 million, net of tax, decreased the unrecognized actuarial loss by $9.0 million and increased our postretirement liabilities by $3.5 million.

Further, our fiscal 2009 costs were determined using a September 30, 2008 measurement date. As of September 30, 2008, interest and corporate bond rates utilized to determine our discount rates were significantly higher than the interest and corporate bond rates as of June 30, 2007, the measurement date for our fiscal 2008 net periodic cost. Accordingly, we increased our discount rate used to determine our fiscal 2009 pension and benefit costs to 7.57 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is mitigated by the fact that assets are "smoothed" for purposes of determining net periodic pension cost. Accordingly, asset gains and losses are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Therefore, our fiscal 2009 pension and postretirement medical costs were materially the same as in fiscal 2008.

For the nine months ended June 30, 2009 and 2008, our total net periodic pension and other benefits cost was $36.2 million and $35.9 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2009. Based upon this valuation, we contributed $21 million to our pension plans in June 2009. The need for this funding reflected the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during the latter half of calendar year 2008. This contribution increased the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $11 million to these plans during fiscal 2009.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts are impacted by actual investment returns, changes in interest rates and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage, natural gas marketing and pipeline, storage and other segments for the three and nine-month periods ended June 30, 2009 and 2008.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
METERS IN SERVICE, end of period				
Residential	2,924,160	2,922,415	2,924,160	2,922,415
Commercial	274,739	271,542	274,739	271,542
Industrial	2,195	2,265	2,195	2,265
Public authority and other	9,231	9,234	9,231	9,234
Total meters	3,210,325	3,205,456	3,210,325	3,205,456
INVENTORY STORAGE BALANCE — Bcf	37.9	41.7	37.9	41.7
SALES VOLUMES — MMcf[(1)]				
Gas sales volumes				
Residential	19,043	18,584	147,718	151,549
Commercial	14,398	15,199	79,416	82,325
Industrial	3,921	4,687	15,079	17,899
Public authority and other	2,719	2,887	10,874	9,919
Total gas sales volumes	40,081	41,357	253,087	261,692
Transportation volumes	30,637	33,211	102,091	109,002
Total throughput	70,718	74,568	355,178	370,694
OPERATING REVENUES (000's)[(1)]				
Gas sales revenues				
Residential	$ 224,629	$ 352,893	$1,657,185	$1,878,855
Commercial	106,739	213,594	744,248	903,771
Industrial	21,028	53,843	117,442	167,154
Public authority and other	13,712	33,135	82,097	100,983
Total gas sales revenues	366,108	653,465	2,600,972	3,050,763
Transportation revenues	13,756	14,163	46,411	46,954
Other gas revenues	7,121	9,011	25,990	28,955
Total operating revenues	$ 386,985	$ 676,639	$2,673,373	$3,126,672
Average transportation revenue per Mcf	$ 0.45	$ 0.43	$ 0.45	$ 0.43
Average cost of gas per Mcf sold	$ 4.87	$ 11.53	$ 7.18	$ 8.77

See footnote following these tables.

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

	Three Months Ended June 30		Nine Months Ended June 30	
	2009	2008	2009	2008
CUSTOMERS, end of period				
Industrial	706	702	706	702
Municipal	63	56	63	56
Other	505	503	505	503
Total	1,274	1,261	1,274	1,261
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	23.3	18.8	23.3	18.8
Pipeline, storage and other	2.5	1.2	2.5	1.2
Total	25.8	20.0	25.8	20.0
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	169,641	181,112	555,169	593,452
NATURAL GAS MARKETING SALES VOLUMES — MMcf[(1)]	103,146	103,403	336,870	348,789
OPERATING REVENUES (000's)[(1)]				
Regulated transmission and storage	$ 49,345	$ 46,286	$ 163,261	$ 142,772
Natural gas marketing	453,504	1,189,722	1,949,657	3,159,092
Pipeline, storage and other	8,226	3,880	36,946	20,629
Total operating revenues	$511,075	$1,239,888	$2,149,864	$3,322,493

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. During the nine months ended June 30, 2009, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2009 to provide reasonable assurance that information

required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of the fiscal year ended September 30, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the nine months ended June 30, 2009, except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2008. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. ***Exhibits***

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

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: August 5, 2009

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number
10.1	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.2	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
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.

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

Form 10-Q

(Mark One)

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

For the quarterly period ended December 31, 2009

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).* Yes ☐ No ☐

* The registrant has not yet been phased into the interactive data requirements.

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

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

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

Number of shares outstanding of each of the issuer's classes of common stock, as of January 28, 2010.

Class	Shares Outstanding
No Par Value	93,054,189

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MPSC	Mississippi Public Service Commission
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2009	September 30, 2009
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,196,043	$6,086,618
Less accumulated depreciation and amortization	1,672,855	1,647,515
Net property, plant and equipment	4,523,188	4,439,103
Current assets		
Cash and cash equivalents	174,829	111,203
Accounts receivable, net	597,012	232,806
Gas stored underground	399,582	352,728
Other current assets	115,155	132,203
Total current assets	1,286,578	828,940
Goodwill and intangible assets	739,907	740,064
Deferred charges and other assets	325,751	335,659
	$6,875,424	$6,343,766
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2009 — 92,970,838 shares; September 30, 2009 — 92,551,709 shares	$ 465	$ 463
Additional paid-in capital	1,802,606	1,791,129
Retained earnings	467,449	405,353
Accumulated other comprehensive loss	(12,444)	(20,184)
Shareholders' equity	2,258,076	2,176,761
Long-term debt	2,159,470	2,169,400
Total capitalization	4,417,546	4,346,161
Current liabilities		
Accounts payable and accrued liabilities	578,805	207,421
Other current liabilities	413,754	457,319
Short-term debt	179,712	72,550
Current maturities of long-term debt	10,131	131
Total current liabilities	1,182,402	737,421
Deferred income taxes	588,423	570,940
Regulatory cost of removal obligation	314,126	321,086
Deferred credits and other liabilities	372,927	368,158
	$6,875,424	$6,343,766

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2009	2008
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 802,894	$1,055,968
Regulated transmission and storage segment	46,860	54,682
Natural gas marketing segment	544,271	787,495
Pipeline, storage and other segment	11,623	16,448
Intersegment eliminations	(112,796)	(198,261)
	1,292,852	1,716,332
Purchased gas cost		
Natural gas distribution segment	508,267	757,584
Regulated transmission and storage segment	—	—
Natural gas marketing segment	484,486	757,472
Pipeline, storage and other segment	1,633	3,903
Intersegment eliminations	(112,383)	(197,839)
	882,003	1,321,120
Gross profit	410,849	395,212
Operating expenses		
Operation and maintenance	123,862	132,677
Depreciation and amortization	53,839	53,126
Taxes, other than income	42,552	44,137
Asset impairments	—	2,078
Total operating expenses	220,253	232,018
Operating income	190,596	163,194
Miscellaneous expense	(269)	(301)
Interest charges	38,708	38,991
Income before income taxes	151,619	123,902
Income tax expense	58,289	47,939
Net income	$ 93,330	$ 75,963
Basic net income per share	$ 1.00	$ 0.83
Diluted net income per share	$ 1.00	$ 0.83
Cash dividends per share	$ 0.335	$ 0.330
Weighted average shares outstanding:		
Basic	92,152	90,471
Diluted	92,509	90,769

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2009	2008
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 93,330	$ 75,963
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	53,839	53,126
Charged to other accounts	36	8
Deferred income taxes	12,832	27,175
Other	4,382	7,683
Net assets/liabilities from risk management activities	(26,891)	9,213
Net change in operating assets and liabilities	(42,372)	(22,453)
Net cash provided by operating activities	95,156	150,715
Cash Flows From Investing Activities		
Capital expenditures	(115,439)	(107,367)
Other, net	(1,873)	(1,210)
Net cash used in investing activities	(117,312)	(108,577)
Cash Flows From Financing Activities		
Net increase in short-term debt	111,335	5,312
Repayment of long-term debt	—	(278)
Cash dividends paid	(31,234)	(30,165)
Issuance of common stock	5,681	6,075
Net cash provided by (used in) financing activities	85,782	(19,056)
Net increase in cash and cash equivalents	63,626	23,082
Cash and cash equivalents at beginning of period	111,203	46,717
Cash and cash equivalents at end of period	$ 174,829	$ 69,799

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2009

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over 3 million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our natural gas distribution and regulated pipeline and storage businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast and include our natural gas marketing operations and pipeline, storage and other operations. These businesses are operated through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH), which is wholly owned by the Company and based in Houston, Texas. Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers and natural gas transportation and storage services to certain of our natural gas distribution divisions and third parties.

We operate the Company through the following four segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment*, which is comprised of our nonregulated natural gas gathering, transmission and storage services.

2. Unaudited Interim Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2009 are not indicative of our results of operations for the full 2010 fiscal year, which ends September 30, 2010. We have evaluated subsequent events from the December 31, 2009 balance sheet date through the date these financial statements were filed with the Securities and Exchange

Commission (SEC). No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009.

Effective October 1, 2009, the Company adopted accounting standards related to the measurement of liabilities at fair value, fair value measurements of plan assets of a defined benefit pension or other postretirement plan, the determination of participating securities in the basic earnings per share calculation, business combination accounting and the accounting and reporting for minority interests. Except as indicated below, the adoption of these standards did not have a material impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the three months ended December 31, 2009.

Measurement of liabilities at fair value — When a quoted price in an active market for an identical liability is not available, we will be required to measure fair value using a valuation technique that uses quoted prices of similar liabilities, quoted prices of identical or similar liabilities when traded as assets, or another valuation technique that is consistent with U.S. generally accepted accounting principles (GAAP), such as the income or market approach. Additionally, when estimating the fair value of a liability, we will not be required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents our transfer of the liability.

Fair value measurements of plan assets of a defined benefit pension or other postretirement plan — The Financial Accounting Standards Board (FASB) issued guidance which requires employers to disclose annually information about fair value measurements of the assets of a defined benefit pension or other postretirement plan in a manner similar to the requirements established for financial and non-financial assets. The objectives of the required disclosures are to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure fair value of plan assets and significant concentrations of risk within plan assets. These disclosures will appear in our Form 10-K for the year ending September 30, 2010.

The determination of participating securities in the basic earnings per share calculation — The FASB issued guidance related to determining whether instruments granted in share-based payment transactions are considered participating securities. The FASB determined that non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents are participating securities and, as a result, companies with these types of participating securities must use the two-class method to compute earnings per share. Based on this guidance, the Company is required to calculate earnings per share using the two-class method and will include non-vested restricted stock and restricted stock units for which vesting is only predicated upon the passage of time in the basic earnings per share calculation. Non-vested restricted stock and restricted stock units for which vesting is predicated, in part upon the achievement of specified performance targets, continue to be excluded from the calculation of earnings per share. Although the provisions of this standard were effective for us as of October 1, 2009, prior-period earnings per share data must be recalculated and adjusted accordingly. The calculation of basic and diluted earnings per share pursuant to the two-class method

is presented in Note 6. The application of the two-class method resulted in the following changes to basic and diluted earnings per share for the three months ended December 31, 2008.

	Three Months Ended December 31, 2008 (In thousands, except per share amounts)
Basic Earnings Per Share	
Basic EPS — as previously reported	$ 0.84
Basic EPS — as adjusted	$ 0.83
Weighted average shares outstanding — as previously reported	90,471
Weighted average shares outstanding — as adjusted	90,471
Diluted Earnings Per Share	
Diluted EPS — as previously reported	$ 0.83
Diluted EPS — as adjusted	$ 0.83
Weighted average shares outstanding — as previously reported	91,066
Weighted average shares outstanding — as adjusted	90,769

Business combination accounting — This new pronouncement establishes new principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. This update significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under the new guidelines, changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact current period income tax expense. The provisions of this standard will apply to any acquisitions we complete after October 1, 2009.

Accounting and reporting for minority interests — In December 2007, the FASB issued guidance related to the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changes the accounting for transactions with minority interest holders. As of December 31, 2009, Atmos Energy did not have any transactions with minority interest holders.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities, and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of December 31, 2009 and September 30, 2009 included the following:

	December 31, 2009	September 30, 2009
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$195,015	$197,743
Merger and integration costs, net	7,049	7,161
Deferred gas costs	53,818	22,233
Environmental costs	988	866
Rate case costs	4,137	5,923
Deferred franchise fees	6,893	10,014
Deferred income taxes, net	639	639
Other	6,323	6,218
	$274,862	$250,797
Regulatory liabilities:		
Deferred gas costs	$ 36,826	$110,754
Regulatory cost of removal obligation	336,315	335,428
Other	7,890	7,960
	$381,031	$454,142

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 applicable state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2009 and 2008:

	Three Months Ended December 31	
	2009	2008
	(In thousands)	
Net income	$ 93,330	$ 75,963
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $390 and $(3,330) for the three months ended December 31, 2009 and 2008	664	(5,433)
Other than temporary impairment of investments, net of tax expense of $790 for the three months ended December 31, 2008	—	1,288
Amortization of interest rate hedging transactions, net of tax expense of $248 and $482 for the three months ended December 31, 2009 and 2008	422	787
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $4,254 and $(13,817) for the three months ended December 31, 2009 and 2008	6,654	(22,544)
Comprehensive income	$101,070	$ 50,061

Accumulated other comprehensive loss, net of tax, as of December 31, 2009 and September 30, 2009 consisted of the following unrealized gains (losses):

	December 31, 2009	September 30, 2009
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 3,124	$ 2,460
Treasury lock agreements	(7,076)	(7,498)
Cash flow hedges	(8,492)	(15,146)
	$(12,444)	$(20,184)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the first quarter there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. However, our pipeline, storage and other segment uses financial instruments acquired from Atmos Energy Marketing, LLC (AEM) on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause payments to be accelerated when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2009-2010 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 29 percent, or 26.9 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in

revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

Our natural gas marketing segment, through AEM, 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.

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 55 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments.

Also, in our natural gas marketing segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on December 31, 2009, AEH had net open positions (including existing storage) of 0.5 Bcf.

Interest Rate Risk Management Activities

Currently, we are not managing interest rate risk with financial instruments. However, in prior years, we periodically managed interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a cumulative net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts of these Treasury locks will be recognized through fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of December 31, 2009, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2009, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other
			Quantity (MMcf)	
Commodity contracts	Fair Value	—	(17,318)	(2,420)
	Cash Flow	—	27,127	(4,660)
	Not designated	22,182	44,903	450
		22,182	54,712	(6,630)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of December 31, 2009 and September 30, 2009. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $1.3 million of cash due on margin as of December 31, 2009 and $11.7 million of cash held on deposit in margin accounts as of September 30, 2009 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed

consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
December 31, 2009:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 37,258	$ 37,258
Noncurrent commodity contracts	Deferred charges and other assets	—	5,920	5,920
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(36,276)	(36,276)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(2,053)	(2,053)
Total		—	4,849	4,849
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	849	39,230	40,079
Noncurrent commodity contracts	Deferred charges and other assets	105	7,764	7,869
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(17,076)	(18,157)	(35,233)
Noncurrent commodity contracts	Deferred credits and other liabilities	(1,348)	(1,380)	(2,728)
Total		(17,470)	27,457	9,987
Total Financial Instruments		$(17,470)	$ 32,306	$ 14,836

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
September 30, 2009:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 53,526	$ 53,526
Noncurrent commodity contracts	Deferred charges and other assets	—	6,800	6,800
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(47,146)	(47,146)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(999)	(999)
Total		—	12,181	12,181
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	4,395	27,559	31,954
Noncurrent commodity contracts	Deferred charges and other assets	1,620	7,964	9,584
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(20,181)	(19,657)	(39,838)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,349)	(1,349)
Total		(14,166)	14,517	351
Total Financial Instruments		$(14,166)	$ 26,698	$ 12,532

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our condensed consolidated income statement, by operating segment, as applicable, for the three months ended December 31, 2009 and 2008.

Hedge ineffectiveness for our natural gas marketing and pipeline storage and other segments is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended December 31, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $45.3 million and $20.4 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three months ended December 31, 2009 and 2008 is presented below.

	Three Months Ended December 31, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ (2,182)	$ (457)	$ (2,639)
Fair value adjustment for natural gas inventory designated as the hedged item	43,312	5,871	49,183
Total impact on revenue	$41,130	$5,414	$46,544
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 64	$ —	$ 64
Timing ineffectiveness	41,066	5,414	46,480
	$41,130	$5,414	$46,544

	Three Months Ended December 31, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 25,683	$ 3,939	$ 29,622
Fair value adjustment for natural gas inventory designated as the hedged item	(11,860)	(1,553)	(13,413)
Total impact on revenue	$ 13,823	$ 2,386	$ 16,209
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 1,952	$ —	$ 1,952
Timing ineffectiveness	11,871	2,386	14,257
	$ 13,823	$ 2,386	$ 16,209

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot to forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 2009 and 2008 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized or will realize when the underlying physical and financial transactions are settled.

	Three Months Ended December 31, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(23,337)	$220	$(23,117)
Loss arising from ineffective portion of commodity contracts	—	(1,218)	—	(1,218)
Total impact on revenue	—	(24,555)	220	(24,335)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(670)	—	—	(670)
Total Impact from Cash Flow Hedges	$(670)	$(24,555)	$220	$(25,005)

	Three Months Ended December 31, 2008			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(28,244)	$7,968	$(20,276)
Loss arising from ineffective portion of commodity contracts	—	4,192	—	4,192
Total impact on revenue	—	(24,052)	7,968	(16,084)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)	—	—	(1,269)
Total Impact from Cash Flow Hedges	$(1,269)	$(24,052)	$7,968	$(17,353)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 2009 and 2008. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended December 31	
	2009	2008
	(In thousands)	
Decrease in fair value:		
Forward commodity contracts	$ (7,447)	$(35,115)
Recognition of losses in earnings due to settlements:		
Treasury lock agreements	422	787
Forward commodity contracts	14,101	12,571
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ 7,076	$(21,757)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Deferred losses recorded in AOCI associated with our treasury lock agreements are recognized into earnings as they are amortized, while deferred losses associated with commodity contracts are recognized into earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 2009:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,687)	$(6,887)	$ (8,574)
Thereafter	(5,389)	(1,605)	(6,994)
Total[(1)]	$(7,076)	$(8,492)	$(15,568)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended December 31, 2009 and 2008 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized or will realize when the underlying physical and financial transactions are settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

	Three Months Ended December 31	
	2009	2008
	(In thousands)	
Natural gas marketing commodity contracts	$14,275	$(3,832)
Pipeline, storage and other commodity contracts	1,007	(83)
Total impact on revenue	$15,282	$(3,915)

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information and minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the first quarter of fiscal 2010, there were no changes in these methods.

Effective October 1, 2009, the authoritative guidance related to nonrecurring fair value measurements became effective for us for certain assets including asset retirement obligations, most nonfinancial assets and liabilities that may be acquired in a business combination and impairment analyses performed for nonfinancial assets. The adoption of the FASB's fair value guidance for the reporting of these nonrecurring fair value measurements did not have a material impact on our financial position, results of operations or cash flows for the three months ended December 31, 2009.

Although fair value measurements also apply to the valuation of our pension and post-retirement plan assets, the current fair value disclosure requirements are not applicable to our pension and post-retirement plan assets. Accordingly, these plan assets are not included in the tabular disclosures below. However, similar disclosures about fair value measurements for our pension and post-retirement plan assets will be disclosed in our Annual Report on Form 10-K for the fiscal year ending September 30, 2010.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009. Assets

and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[1]	December 31, 2009
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 954	$ —	$ —	$ 954
Natural gas marketing segment	17,209	72,963	—	(56,568)	33,604
Total financial instruments	17,209	73,917	—	(56,568)	34,558
Hedged portion of gas stored underground					
Natural gas marketing segment	99,690	—	—	—	99,690
Pipeline, storage and other segment[2]	12,529	—	—	—	12,529
Total gas stored underground	112,219	—	—	—	112,219
Available-for-sale securities	42,184	—	—	—	42,184
Total assets	$171,612	$73,917	$ —	$(56,568)	$188,961
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$18,424	$ —	$ —	$ 18,424
Natural gas marketing segment	38,332	19,534	—	(55,253)	2,613
Total liabilities	$ 38,332	$37,958	$ —	$(55,253)	$ 21,037

(1) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and authoritative accounting literature. In addition, as of December 31, 2009, we had $1.3 million of cash due on margin accounts used to collateralize certain financial instruments which has been reflected as a reduction to our financial instrument assets.

(2) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of December 31, 2009:

	December 31, 2009
	(In thousands)
Carrying Amount	$2,172,827
Fair Value	$2,310,405

5. Debt

Long-term debt

Long-term debt at December 31, 2009 and September 30, 2009 consisted of the following:

	December 31, 2009	September 30, 2009
	(In thousands)	
Unsecured 7.375% Senior Notes, due May 2011	$ 350,000	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 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
Rental property term note due in installments through 2013	524	524
Total long-term debt	2,172,827	2,172,827
Less:		
Original issue discount on unsecured senior notes and debentures	(3,226)	(3,296)
Current maturities	(10,131)	(131)
	$2,159,470	$2,169,400

As noted above, our Series A, 1995-2, 6.27% medium term note will mature in December 2010; accordingly, it has been classified within the current maturities of long-term debt.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. At December 31, 2009, there was a total of $179.7 million outstanding under our commercial paper program. At September 30, 2009, there was a total of $72.6 million outstanding under our commercial paper program. As of December 31, 2009, our commercial paper had maturities of less than two weeks with an interest rate of 0.27 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through a $566.7 million commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately

$800 million of working capital funding. The first facility is a five-year unsecured facility, expiring December 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At December 31, 2009, there were no borrowings under this facility, but we had $179.7 million of commercial paper outstanding leaving $387.0 million available.

The second facility is a $200 million unsecured 364-day facility that expires in October 2010. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.75 percent to 3.00 percent, based on the Company's credit ratings. At December 31, 2009, there were no borrowings outstanding under this facility.

The third facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At December 31, 2009, there were no borrowings outstanding under this facility.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2009, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, the Company has a $200 million intercompany revolving credit facility provided by AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved the facility through December 31, 2010. There was $35.5 million outstanding under this facility at December 31, 2009.

Nonregulated Operations

On December 10, 2009, AEM and the participating banks amended and restated AEM's $450 million committed revolving credit facility extending it to December 9, 2010.

AEM uses this facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; and (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent plus 0.50 percent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; and (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 2.250 percent to 2.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $17 million to $27 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At December 31, 2009, there were no borrowings outstanding under this credit facility. However, at December 31, 2009, AEM letters of credit totaling $38.0 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 $250.8 million at December 31, 2009.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At December 31, 2009, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.96 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $75 million to $112.5 million. As defined in the financial covenants, at December 31, 2009, AEM's net working capital was $246.7 million and its tangible net worth was $257.9 million.

To supplement borrowings under this facility, AEM has a $200 million intercompany demand credit facility with AEH, which bears interest at the greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Amounts outstanding under this facility are subordinated to AEM's committed credit facility. There was $45.0 million in borrowings outstanding under this facility at December 31, 2009.

Finally, AEH has a $200 million intercompany demand credit facility with AEC, which bears interest at greater of (i) the one-month LIBOR rate plus 2.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved the new facility through December 31, 2010. There were no borrowings outstanding under this facility at December 31, 2009.

Shelf Registration

On March 23, 2009, we filed a registration statement with the SEC to issue, from time to time, up to $900 million in common stock and/or debt securities available for issuance.

As of December 31, 2009, we had $450 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $200 million of equity securities and $250 million of debt securities.

As of February 2, 2010, we had received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under a new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities. We expect to file a registration statement with the SEC to register such securities as soon as practicable.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of December 31, 2009. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

As discussed in Note 2, since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share as of October 1, 2009. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. The presentation of earnings per share for previously reported periods has been adjusted due to the retrospective adoption of this standard. Basic and diluted earnings per share for the three months ended December 31, 2009 and 2008 are calculated as follows:

	Three Months Ended December 31	
	2009	2008
	(In thousands, except per share amounts)	
Basic Earnings Per Share		
Net income	$93,330	$75,963
Less: Income allocated to participating securities	1,037	708
Net income available to common shareholders	$92,293	$75,255
Basic weighted average shares outstanding	92,152	90,471
Net income per share — Basic	$ 1.00	$ 0.83
Diluted Earnings Per Share		
Net income available to common shareholders	$92,293	$75,255
Effect of dilutive stock options and other shares	3	1
Net income available to common shareholders	$92,296	$75,256
Basic weighted average shares outstanding	92,152	90,471
Additional dilutive stock options and other shares	357	298
Diluted weighted average shares outstanding	92,509	90,769
Net income per share — Diluted	$ 1.00	$ 0.83

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three months ended December 31, 2009 as their exercise price was less than the average market price of the common stock during that period. There were approximately 231,000 out-of-the-money stock

options excluded from the computation of diluted earnings per share for the three months ended December 31, 2008.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2009 and 2008 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,993	$ 3,703	$3,360	$2,946
Interest cost	6,524	7,554	3,018	3,520
Expected return on assets	(6,320)	(6,238)	(615)	(573)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(193)	(183)	(375)	—
Amortization of actuarial loss	2,822	955	93	—
Net periodic pension cost	$ 6,826	$ 5,791	$5,859	$6,271

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2009 and 2008 are as follows:

	Pension Benefits		Other Benefits	
	2009	2008	2009	2008
Discount rate	5.52%	7.57%	5.52%	7.57%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2010. Based upon this valuation, we expect we will be required to contribute less than $30 million to our pension plans by September 15, 2010.

We contributed $3.2 million to our other post-retirement benefit plans during the three months ended December 31, 2009. We expect to contribute a total of approximately $13 million to these plans during fiscal 2010.

For our Supplemental Executive Retirement Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of December 31, 2009:				
Domestic equity mutual funds	$26,333	$4,052	$—	$30,385
Foreign equity mutual funds	4,081	953	—	5,034
Money market funds	6,765	—	—	6,765
	$37,179	$5,005	$—	$42,184
As of September 30, 2009:				
Domestic equity mutual funds	$26,012	$3,012	$—	$29,024
Foreign equity mutual funds	4,047	893	—	4,940
Money market funds	7,735	—	—	7,735
	$37,794	$3,905	$—	$41,699

The following table presents interest and dividends on available-for-sale securities for the three months ended December 31, 2009 and 2008:

	Three Months Ended December 31	
	2009	2008
	(In thousands)	
Interest	$ 3	$ —
Dividends	101	167
Total interest and dividends	$104	$167

The following table presents realized losses on available-for-sale securities for the three months ended December 31, 2009 and 2008. The gross realized investment losses exclude losses from other-than-temporary impairment:

	Three Months Ended December 31	
	2009	2008
	(In thousands)	
Gross realized investment gains	$—	$ —
Gross realized investment losses	—	(81)
Net realized losses	$—	$(81)

During the three months ended December 31, 2008, we recorded a $2.1 million noncash charge to impair certain available-for-sale investments due to deterioration of the market and the uncertainty of a full recovery. We did not maintain any investments that are in an unrealized loss position at December 31, 2009.

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 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30,

2009, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2009. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2009, AEM was committed to purchase 94.7 Bcf within one year, 12.3 Bcf within one to three years and 1.9 Bcf after three years under indexed contracts. AEM is committed to purchase 3.7 Bcf within one year, 0.6 Bcf within one to three years and 0.2 Bcf after three years under fixed price contracts with prices ranging from $4.57 to $6.43 per Mcf. Purchases under these contracts totaled $354.1 million and $527.5 million for the three months ended December 31, 2009 and 2008.

Our natural gas distribution divisions, except for our 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 this service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of December 31, 2009 are as follows (in thousands):

2010	$202,676
2011	7,491
2012	7,256
2013	7,481
2014	2,540
Thereafter	—
	$227,444

Our natural gas marketing and pipeline, storage and other segments maintain long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. There were no material changes to the estimated storage and transportation fees for the quarter ended December 31, 2009.

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the

Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

After responding to two sets of data requests received from the Commission, the Commission agreed to allow us to conduct our own internal investigation into compliance with the Commission's rules. We have completed our internal investigation and submitted the results to the Commission. During our investigation, we identified certain non-compliant transactions, and we continue to fully cooperate with the Commission as we work to resolve this matter. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

As of December 31, 2009, rate cases were in progress in our City of Dallas, Colorado, Kentucky, Missouri and Georgia service areas and annual rate filing mechanisms were in progress in our Louisiana service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the three months ended December 31, 2009, there were no material changes in our concentration of credit risk.

10. Segment Information

As discussed in Note 1 above, we operate the Company through the following four segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which includes our nonregulated natural gas transmission and storage services.

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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2009. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three month periods ended December 31, 2009 and 2008 by segment are presented in the following tables:

	Three Months Ended December 31, 2009					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$802,686	$19,842	$460,821	$ 9,503	$ —	$1,292,852
Intersegment revenues	208	27,018	83,450	2,120	(112,796)	—
	802,894	46,860	544,271	11,623	(112,796)	1,292,852
Purchased gas cost	508,267	—	484,486	1,633	(112,383)	882,003
Gross profit	294,627	46,860	59,785	9,990	(413)	410,849
Operating expenses						
Operation and maintenance	96,033	17,579	8,755	1,908	(413)	123,862
Depreciation and amortization	47,857	4,942	411	629	—	53,839
Taxes, other than income	37,990	3,267	935	360	—	42,552
Total operating expenses	181,880	25,788	10,101	2,897	(413)	220,253
Operating income	112,747	21,072	49,684	7,093	—	190,596
Miscellaneous income (expense)	657	43	208	453	(1,630)	(269)
Interest charges	29,678	7,968	2,378	314	(1,630)	38,708
Income before income taxes	83,726	13,147	47,514	7,232	—	151,619
Income tax expense	32,278	4,693	18,502	2,816	—	58,289
Net income	$ 51,448	$ 8,454	$ 29,012	$ 4,416	$ —	$ 93,330
Capital expenditures	$100,462	$13,759	$ 406	$ 812	$ —	$ 115,439

	Three Months Ended December 31, 2008					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,055,772	$30,222	$616,844	$13,494	$ —	$1,716,332
Intersegment revenues	196	24,460	170,651	2,954	(198,261)	—
	1,055,968	54,682	787,495	16,448	(198,261)	1,716,332
Purchased gas cost	757,584	—	757,472	3,903	(197,839)	1,321,120
Gross profit	298,384	54,682	30,023	12,545	(422)	395,212
Operating expenses						
Operation and maintenance	96,218	27,337	8,460	1,170	(508)	132,677
Depreciation and amortization	47,139	4,955	401	631	—	53,126
Taxes, other than income	40,746	2,788	593	10	—	44,137
Asset impairments	1,776	232	56	14	—	2,078
Total operating expenses	185,879	35,312	9,510	1,825	(508)	232,018
Operating income	112,505	19,370	20,513	10,720	86	163,194
Miscellaneous income (expense)	3,121	815	301	2,161	(6,699)	(301)
Interest charges	32,887	8,079	3,902	736	(6,613)	38,991
Income before income taxes	82,739	12,106	16,912	12,145	—	123,902
Income tax expense	32,606	4,445	6,337	4,551	—	47,939
Net income	$ 50,133	$ 7,661	$ 10,575	$ 7,594	$ —	$ 75,963
Capital expenditures	$ 89,003	$ 5,060	$ 29	$13,275	$ —	$ 107,367

Balance sheet information at December 31, 2009 and September 30, 2009 by segment is presented in the following tables:

	December 31, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,758,014	$681,993	$ 7,354	$ 75,827	$ —	$4,523,188
Investment in subsidiaries	596,473	—	(2,096)	—	(594,377)	—
Current assets						
Cash and cash equivalents	33,718	—	140,654	457	—	174,829
Assets from risk management activities	849	—	22,033	3,337	(3,337)	22,882
Other current assets	744,761	16,511	331,107	102,735	(106,247)	1,088,867
Intercompany receivables	522,405	—	—	144,092	(666,497)	—
Total current assets	1,301,733	16,511	493,794	250,621	(776,081)	1,286,578
Intangible assets	—	—	1,304	—	—	1,304
Goodwill	571,592	132,300	24,282	10,429	—	738,603
Noncurrent assets from risk management activities	105	—	11,571	—	—	11,676
Deferred charges and other assets	289,106	6,476	1,024	17,469	—	314,075
	$6,517,023	$837,280	$537,233	$354,346	$(1,370,458)	$6,875,424
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,258,076	$179,654	$119,019	$297,800	$ (596,473)	$2,258,076
Long-term debt	2,159,077	—	—	393	—	2,159,470
Total capitalization	4,417,153	179,654	119,019	298,193	(596,473)	4,417,546
Current liabilities						
Current maturities of long-term debt	10,000	—	—	131	—	10,131
Short-term debt	215,162	—	45,000	—	(80,450)	179,712
Liabilities from risk management activities	17,076	—	4,628	3	(3,337)	18,370
Other current liabilities	689,643	10,379	256,627	41,241	(23,701)	974,189
Intercompany payables	—	550,047	116,450	—	(666,497)	—
Total current liabilities	931,881	560,426	422,705	41,375	(773,985)	1,182,402
Deferred income taxes	489,899	92,932	(6,422)	12,014	—	588,423
Noncurrent liabilities from risk management activities	1,348	—	1,319	—	—	2,667
Regulatory cost of removal obligation	314,126	—	—	—	—	314,126
Deferred credits and other liabilities	362,616	4,268	612	2,764	—	370,260
	$6,517,023	$837,280	$537,233	$354,346	$(1,370,458)	$6,875,424

	September 30, 2009					
	Natural Gas Distribution	Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
			(In thousands)			
ASSETS						
Property, plant and equipment, net	$3,703,471	$672,829	$ 7,112	$ 55,691	$ —	$4,439,103
Investment in subsidiaries	547,936	—	(2,096)	—	(545,840)	—
Current assets						
Cash and cash equivalents	23,655	—	87,266	282	—	111,203
Assets from risk management activities	4,395	—	27,424	2,765	(2,941)	31,643
Other current assets	499,155	17,017	157,846	112,551	(100,475)	686,094
Intercompany receivables	552,408	—	—	128,104	(680,512)	—
Total current assets	1,079,613	17,017	272,536	243,702	(783,928)	828,940
Intangible assets	—	—	1,461	—	—	1,461
Goodwill	571,592	132,300	24,282	10,429	—	738,603
Noncurrent assets from risk management activities	1,620	—	12,415	6	(6)	14,035
Deferred charges and other assets	290,327	11,932	1,065	18,300	—	321,624
	$6,194,559	$834,078	$316,775	$328,128	$(1,329,774)	$6,343,766
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,176,761	$171,200	$ 83,354	$293,382	$ (547,936)	$2,176,761
Long-term debt	2,169,007	—	—	393	—	2,169,400
Total capitalization	4,345,768	171,200	83,354	293,775	(547,936)	4,346,161
Current liabilities						
Current maturities of long-term debt	—	—	—	131	—	131
Short-term debt	158,942	—	—	—	(86,392)	72,550
Liabilities from risk management activities	20,181	—	4,060	182	(2,941)	21,482
Other current liabilities	510,749	9,251	116,078	19,167	(11,987)	643,258
Intercompany payables	—	557,190	123,322	—	(680,512)	—
Total current liabilities	689,872	566,441	243,460	19,480	(781,832)	737,421
Deferred income taxes	477,352	92,250	(10,675)	12,013	—	570,940
Noncurrent liabilities from risk management activities	—	—	6	—	(6)	—
Regulatory cost of removal obligation	321,086	—	—	—	—	321,086
Deferred credits and other liabilities	360,481	4,187	630	2,860	—	368,158
	$6,194,559	$834,078	$316,775	$328,128	$(1,329,774)	$6,343,766

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of December 31, 2009, the related condensed consolidated statements of income for the three-month periods ended December 31, 2009 and 2008, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2009 and 2008. 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, 2009, 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, 2009, 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, 2009, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
February 3, 2010

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, 2009.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties, which are discussed in more detail in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the possible impact of future additional regulatory and financial risks associated with global warming and climate change; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business; natural disasters, terrorist activities or other events; and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over 3 million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

We operate the Company through the following four segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment*, which is comprised of our nonregulated natural gas gathering, transmission and storage services.

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, the 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 fiscal year ended September 30, 2009 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the three months ended December 31, 2009.

RESULTS OF OPERATIONS

We reported net income of $93.3 million, or $1.00 per diluted share for the three months ended December 31, 2009 compared with net income of $76.0 million, or $0.83 per diluted share in the prior-year quarter. Regulated operations contributed 64 percent of our net income during this period with our nonregulated operations contributing the remaining 36 percent. The primary driver in the 23 percent quarter-over-quarter increase in net income was due to our natural gas marketing segment experiencing a significant increase in unrealized margins primarily through our asset optimization activities. The favorable movement in our unrealized margins was primarily the result of two factors. First, we experienced a narrowing of spreads between current cash prices and forward natural gas prices. Secondly, we elected to defer storage withdrawal gains and roll the associated financial instruments from the current quarter to future months in order to maximize our overall economic value that should ultimately be realized. As a result, gains that are typically realized during the first quarter remained unrealized as of December 31, 2009.

During the quarter, we also experienced the ongoing impact of challenging economic times. This was reflected in declines in the demand for natural gas as a result of idle production and plant closures, which contributed to a 29 percent quarter-over-quarter decrease in consolidated throughput in our regulated transmission and storage segment and a seven percent quarter-over-quarter decrease in consolidated sales volumes in our natural gas marketing segment. However, colder than normal weather during the current quarter, which resulted in increased throughput of seven percent, and recent improvements in rate designs in our natural gas distribution segment partially offset these declines.

During the quarter we continued to successfully access the capital markets. In October 2009, we renewed a $200 million 364-day committed credit facility and in December 2009 we renewed a $450 million 364-day committed credit facility for our nonregulated operations. These facilities should help ensure we have sufficient liquidity to fund our working capital needs.

The following table presents our consolidated financial highlights for the three months ended December 31, 2009 and 2008:

	Three Months Ended December 31	
	2009	2008
	(In thousands, except per share data)	
Operating revenues	$1,292,852	$1,716,332
Gross profit	410,849	395,212
Operating expenses	220,253	232,018
Operating income	190,596	163,194
Miscellaneous expense	(269)	(301)
Interest charges	38,708	38,991
Income before income taxes	151,619	123,902
Income tax expense	58,289	47,939
Net income	$ 93,330	$ 75,963
Diluted net income per share	$ 1.00	$ 0.83

Our consolidated net income during the three months ended December 31, 2009 and 2008 was earned in each of our business segments as follows:

	Three Months Ended December 31		
	2009	2008	Change
	(In thousands)		
Natural gas distribution segment	$51,448	$50,133	$ 1,315
Regulated transmission and storage segment	8,454	7,661	793
Natural gas marketing segment	29,012	10,575	18,437
Pipeline, storage and other segment	4,416	7,594	(3,178)
Net income	$93,330	$75,963	$17,367

The following table reflects our consolidated net income and diluted earnings per share in our regulated and nonregulated operations:

	Three Months Ended December 31		
	2009	2008	Change
	(In thousands, except per share data)		
Regulated operations	$59,902	$57,794	$ 2,108
Nonregulated operations	33,428	18,169	15,259
Consolidated net income	$93,330	$75,963	$17,367
Diluted EPS from regulated operations	$ 0.64	$ 0.63	$ 0.01
Diluted EPS from nonregulated operations	0.36	0.20	0.16
Consolidated diluted EPS	$ 1.00	$ 0.83	$ 0.17

Three Months Ended December 31, 2009 compared with Three Months Ended December 31, 2008

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

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

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Prior to January 1, 2009, timing differences existed between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. These timing differences had a significant temporary effect on operating income in periods with volatile gas prices, particularly in our Mid-Tex Division. Beginning January 1, 2009, changes in our

franchise fee agreements in our Mid-Tex Division became effective, which have significantly reduced the impact of this timing difference. Although this timing difference will still be present for gross receipts taxes, the timing differences described above have been and should continue to be less significant.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2009 and 2008 are presented below.

	Three Months Ended December 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Gross profit	$294,627	$298,384	$(3,757)
Operating expenses	181,880	185,879	(3,999)
Operating income	112,747	112,505	242
Miscellaneous income	657	3,121	(2,464)
Interest charges	29,678	32,887	(3,209)
Income before income taxes	83,726	82,739	987
Income tax expense	32,278	32,606	(328)
Net income	$ 51,448	$ 50,133	$ 1,315
Consolidated natural gas distribution sales volumes — MMcf	99,314	91,446	7,868
Consolidated natural gas distribution transportation volumes — MMcf	35,207	34,336	871
Total consolidated natural gas distribution throughput — MMcf	134,521	125,782	8,739
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.45	$ 0.01
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.12	$ 8.28	$ (3.16)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the three months ended December 31, 2009 and 2008. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31		
	2009	2008	Change
	(In thousands)		
Mid-Tex	$ 50,381	$ 52,678	$(2,297)
Kentucky/Mid-States	17,803	19,025	(1,222)
Louisiana	13,407	14,584	(1,177)
West Texas	11,757	8,013	3,744
Mississippi	9,802	8,435	1,367
Colorado-Kansas	8,606	8,601	5
Other	991	1,169	(178)
Total	$112,747	$112,505	$ 242

The $3.8 million decrease in natural gas distribution gross profit primarily reflects a prior-year quarter event that did not recur in the current year as well as revenue taxes as follows:

- $8.0 million decrease due to a prior year non-recurring update to our estimate for gas delivered to customers but not yet billed to reflect changes in base rates in several of our jurisdictions.
- $7.6 million decrease due to lower revenue-related taxes primarily as a result of lower-priced natural gas, partially offset by the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income discussed below.

These decreases were partially offset by:

- $9.8 million net increase in rate adjustments, primarily in West Texas, Louisiana, Mid-Tex and Mississippi.
- $2.2 million increase as a result of a seven percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $4.0 million, primarily due to the following:

- $2.8 million decrease in taxes other than income due to lower franchise fees and state gross receipts taxes.
- $1.8 million decrease due to the absence of an impairment charge for available-for-sale securities recorded in December 2008.
- $0.8 million decrease in allowance for doubtful accounts due to a 38 percent quarter-over-quarter decline in the average cost of gas.

These decreases were partially offset by a $1.5 million increase in employee-related expenses.

Miscellaneous income decreased $2.5 million due to lower interest income. Interest charges decreased $3.2 million primarily due to lower short-term debt balances and interest rates.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the three months ended December 31, 2009 are discussed below. The amounts described below represent the operating income that was requested or received

in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $10.2 million resulting from ratemaking activity became effective in the quarter ended December 31, 2009 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Rate case filings	$ 1,397
Annual rate filing mechanisms	7,172
Other rate activity	1,675
	$10,244

Additionally, the following ratemaking efforts were in progress during the first quarter of fiscal 2010 but had not been completed as of December 31, 2009.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Mid-Tex	Rate Case[1]	Dallas & Environs	$ 7,743
Colorado/Kansas	Rate Case[2]	Colorado	3,834
	Ad Valorem True Up[3]	Kansas	392
KY/Mid-States	Rate Case	Kentucky	9,486
	Rate Case	Missouri	6,439
	Rate Case	Georgia	3,776
	ISRS(4)	Missouri	597
Louisiana	RSC	Louisiana	1,841
			$34,108

(1) In January 2010, we resolved our pending rate case for the City of Dallas and Eviron's. Initiated in November 2008 and subsequently amended, the case sought an increase of $8.8 million for City of Dallas and Environs customers. In its final order, the Railroad Commission of Texas approved a $3.0 million increase in operating income earned from these customers based on a 10.4 percent return on equity. Net of the GRIP 2008 rates that should be superseded, operating income will increase $0.2 million. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

(2) The Commission approved an increase of $1.9 million and new rates were implemented beginning in January 2010.

(3) In December 2009, our Colorado/Kansas Division filed an Ad Valorem True-up filing for $0.4 million. The Commission approved the increase of $0.4 million and new rates were implemented beginning in January 2010.

(4) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

Additionally, in January 2010, our Colorado/Kansas Division filed a rate case in Kansas requesting an increase in operating income of $6.0 million.

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we

continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2010 Rate Case Filings:			
Kentucky/Mid-States	Virginia	$1,397	11/23/2009
Total 2010 Rate Case Filings		$1,397	

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the quarter ended December 31, 2009.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2010 Filings:				
West Texas	Lubbock	12/31/2008	$2,704	10/1/2009
West Texas	Amarillo	12/31/2008	1,285	10/1/2009
Mississippi	Mississippi	6/30/2009	3,183	12/15/2009
Total 2010 Filings			$7,172	

The following table summarizes other ratemaking activity during the quarter ended December 31, 2009:

Division	Jurisdiction	Rate Activity	Increase in Operating Income	Effective Date
			(In thousands)	
2010 Other Rate Activity:				
Kentucky/Mid-States	Georgia	PRP Surcharge[1]	$ 909	10/1/2009
Colorado-Kansas	Kansas	GSRS[2]	766	12/12/2009
Total 2010 Other Rate Activity			$1,675	

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for

our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2009 and 2008 are presented below.

	Three Months Ended December 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 26,711	$ 24,352	$ 2,359
Third-party transportation	15,242	25,366	(10,124)
Storage and park and lend services	2,605	2,357	248
Other	2,302	2,607	(305)
Gross profit	46,860	54,682	(7,822)
Operating expenses	25,788	35,312	(9,524)
Operating income	21,072	19,370	1,702
Miscellaneous income	43	815	(772)
Interest charges	7,968	8,079	(111)
Income before income taxes	13,147	12,106	1,041
Income tax expense	4,693	4,445	248
Net income	$ 8,454	$ 7,661	$ 793
Gross pipeline transportation volumes — MMcf	157,773	192,172	(34,399)
Consolidated pipeline transportation volumes — MMcf	95,938	135,858	(39,920)

The $7.8 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $4.2 million decrease due to a 29 percent decline in system throughput resulting from lower production and drilling activity due to lower prices and demand.
- $3.9 million decrease resulting from lower transportation fees on through-system deliveries due to narrower basis spreads.
- $1.3 million decrease in market-based demand fees and compression activity associated with lower demand throughput.

These decreases were partially offset by a $1.5 million increase associated with our GRIP filings.

Operating expenses decreased $9.5 million primarily due to lower levels of pipeline maintenance activities.

Natural Gas Marketing Segment

Atmos Energy Marketing LLC's (AEM) primary business is to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. In addition, AEM utilizes proprietary and customer-owned transportation and storage assets to provide 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 financial instruments (delivered gas business). As a result, AEM's margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEM also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity we own or control in our natural gas distribution and natural gas marketing segments. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEM has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEM continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEM may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEM elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to hedge the original financial instruments. If AEM elects to defer the withdrawal of gas, it will reset its financial instruments by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEM also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Due to the nature of these operations, natural gas prices have a significant impact on our natural gas marketing operations. Within our delivered gas business higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our natural gas marketing segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas marketing segment for the three months ended December 31, 2009 and 2008 are presented below. Gross profit margin consists primarily of margins earned

from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended December 31		
	2009	2008	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 16,087	$ 18,553	$ (2,466)
Asset optimization[(1)]	6,429	36,939	(30,510)
	22,516	55,492	(32,976)
Unrealized margins	37,269	(25,469)	62,738
Gross profit	59,785	30,023	29,762
Operating expenses	10,101	9,510	591
Operating income	49,684	20,513	29,171
Miscellaneous income	208	301	(93)
Interest charges	2,378	3,902	(1,524)
Income before income taxes	47,514	16,912	30,602
Income tax expense	18,502	6,337	12,165
Net income	$ 29,012	$ 10,575	$ 18,437
Gross natural gas marketing sales volumes — MMcf	102,261	110,658	(8,397)
Consolidated natural gas marketing sales volumes — MMcf	87,229	93,308	(6,079)
Net physical position (Bcf)	17.4	16.3	1.1

(1) Net of storage fees of $2.5 million and $2.6 million.

AEM's delivered gas business contributed 71 percent to total realized margins during the first quarter of fiscal 2010 with asset optimization activities contributing the remaining 29 percent. The $33.0 million decrease in realized gross profit reflected:

- A $30.5 million decrease in asset optimization margins primarily attributable to the timing of the settlement of open positions. During the current period, AEM elected to defer storage withdrawals and roll the associated financial instruments from the current quarter to forward months. In the prior-year quarter, AEM recognized the gains that it had captured from its optimization activities during late fiscal 2008.
- A $2.5 million decrease in realized delivered gas margins due to an eight percent decrease in gross sales volumes as a result of the current economic climate. Per-unit margins were $0.16/Mcf in the current-year quarter compared with $0.17/Mcf in the prior-year quarter.

The decrease in realized gross profit was more than offset by a $62.7 million increase in unrealized margins due to the narrowing of spreads between current cash prices and forward natural gas prices and our

election to defer storage withdrawal gains during the current quarter. As a result of this election, realized gains that we typically earn during the first quarter remain unrealized. A significant portion of the unrealized gain is anticipated to be realized during the second fiscal quarter of 2010.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, increased $0.6 million primarily due to an increase in employee and other administrative costs.

Asset Optimization Activities

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before associated storage fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement, is referred to as the potential gross profit.

We define potential gross profit as the change in AEM's gross profit from asset optimization activities in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider these measures to be non-GAAP financial measures as they are calculated using both forward-looking storage injections/withdrawals and hedge settlement estimates and historical financial information. These measures are presented because we believe they provide a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. There are no forward-looking GAAP financial measures that are available, which are directly comparable to either of the forward-looking non-GAAP financial measures, economic value or potential gross profit, to which such forward-looking non-GAAP financial measures may be reconciled.

The following table presents AEM's economic value and its potential gross profit (loss) at December 31, 2009 and 2008.

	December 31	
	2009	2008
	(In millions, unless otherwise noted)	
Economic value	$ 22.7	$ 20.7
Associated unrealized (gains) losses	(24.8)	(4.8)
Subtotal	(2.1)	15.9
Related fees[(1)]	(13.1)	(11.6)
Potential gross profit (loss)	$(15.2)	$ 4.3
Net physical position (Bcf)	17.4	16.3

(1) Related fees represent AEM's contractual costs to acquire the storage capacity utilized in its asset optimization activities. The fees primarily consist of demand fees and contractual obligations to sell gas below market index prices in exchange for the right to manage and optimize third party storage assets for the positions AEM has entered into as of December 31, 2009 and 2008.

During the quarter ended December 31, 2009, AEM's economic value decreased from $28.6 million, or $2.07/Mcf at September 30, 2009 to $22.7 million, or $1.30/Mcf. This compares favorably to AEM's economic value at December 31, 2008 of $20.7 million, or $1.27/Mcf.

Early in the quarter, AEM withdrew gas and realized previously captured spreads. However, as current cash prices declined during the quarter, AEM started to inject gas and rolled positions primarily into the second fiscal quarter to increase economic value that it can realize in future periods. As a result of this activity, AEM was a net injector of gas during the quarter. We anticipate the majority of the economic value and corresponding reversal of unrealized mark to market gains will occur in the second fiscal quarter.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit calculated as of December 31, 2009 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS is engaged in nonregulated transmission, storage and natural gas-gathering services. Its primary asset is a proprietary 21 mile pipeline located in New Orleans, Louisiana that is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana, our natural gas marketing segment, and, on a more limited basis; for third parties. APS also owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for additional pipeline capacity to meet customer demand during peak periods.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements. APS also seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time.

Results for this segment are primarily impacted by seasonal weather patterns and, similar to our natural gas marketing segment, volatility in the natural gas markets. Additionally, this segment's results include an unrealized component as APS hedges its risk associated with its asset optimization activities.

Review of Financial and Operating Results

Financial and operational highlights for our pipeline, storage and other segment for the three months ended December 31, 2009 and 2008 are presented below.

	Three Months Ended December 31		
	2009	2008	Change
	(In thousands)		
Asset optimization	$ 97	$ 5,467	$(5,370)
Storage and transportation services[1]	3,448	3,315	133
Other	(170)	989	(1,159)
Unrealized margins	6,615	2,774	3,841
Gross profit	9,990	12,545	(2,555)
Operating expenses	2,897	1,825	1,072
Operating income	7,093	10,720	(3,627)
Miscellaneous income	453	2,161	(1,708)
Interest charges	314	736	(422)
Income before income taxes	7,232	12,145	(4,913)
Income tax expense	2,816	4,551	(1,735)
Net income	$4,416	$ 7,594	$(3,178)

[1] Net of storage and demand fees of $0.6 million and $0.8 million.

Gross profit from our pipeline, storage and other segment decreased $2.6 million primarily due to the following:

- $3.6 million decrease in margins earned from utilizing assets subject to Atmos Pipeline and Storage's asset management plans.
- $1.9 million decrease in basis gains earned from utilizing leased capacity.
- $3.8 million increase in unrealized margins associated with our asset optimization activities.

Operating expenses increased $1.1 million primarily due to the following:

- $0.7 million increase in employee costs.
- $0.3 million increase in property taxes.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2010.

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, investing and financing activities for the three months ended December 31, 2009 and 2008 are presented below.

	Three Months Ended December 31		
	2009	2008	2009 vs. 2008
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 95,156	$ 150,715	$ (55,559)
Investing activities	(117,312)	(108,577)	(8,735)
Financing activities	85,782	(19,056)	104,838
Change in cash and cash equivalents	63,626	23,082	40,544
Cash and cash equivalents at beginning of period	111,203	46,717	64,486
Cash and cash equivalents at end of period	$ 174,829	$ 69,799	$105,030

Cash flows from operating activities

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

For the three months ended December 31, 2009, we generated operating cash flow of $95.2 million from operating activities compared with $150.7 million for the three months ended December 31, 2008, primarily

due to the fluctuation in gas costs. Gas costs, which reached unusually high levels during the 2008 injection season, declined sharply when the economy slipped into the recession and have remained relatively stable since that time. Operating cash flow for the fiscal 2010 first quarter reflects the recovery of lower gas costs through purchased gas recovery mechanisms and sales. This is in contrast to the fiscal 2009 first quarter, where operating cash flow was favorably influenced by the recovery of high gas costs during a period of falling prices.

Cash flows from investing activities

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

Capital expenditures for fiscal 2010 are expected to range from $520 million to $535 million. For the three months ended December 31, 2009, capital expenditures were $115.4 million compared with $107.4 million for the three months ended December 31, 2008. The $8.0 million increase in capital expenditures primarily reflects spending for the relocation of our information technology data center to a new facility.

Cash flows from financing activities

For the three months ended December 31, 2009, our financing activities provided $85.8 million in cash flow compared with using $19.1 million of cash in the prior-year period, primarily due to the following:

- $106.0 million additional cash provided by a period-over-period increase in short-term debt, partially offset by
- $1.1 million additional cash used due to an increase in dividends paid in the current year compared to the prior year.

The following table summarizes our share issuances for the three months ended December 31, 2009 and 2008.

	Three Months Ended December 31	
	2009	**2008**
Shares issued:		
Direct Stock Purchase Plan	79,087	108,582
Retirement Savings Plan and Trust	79,722	155,195
1998 Long-Term Incentive Plan	259,550	520,124
Outside Directors Stock-for-Fee Plan	770	911
Total shares issued	419,129	784,812

The quarter-over-quarter decrease in the number of shares issued primarily reflects the reduced level of shares awarded under our 1998 Long-Term Incentive Plan due to the Company achieving a lower level of performance relative to the target performance established under the Plan during fiscal 2009 compared to fiscal 2008. Further, a higher average stock price during the first quarter of fiscal 2010 compared to the first quarter of 2009 caused us to issue fewer shares during the quarter.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. As of December 31, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $863 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

On March 23, 2009, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $900 million in common stock and/or debt securities. As of December 31, 2009, we had $450 million of availability remaining under the registration statement. However, due to certain restrictions placed by one state regulatory commission on our ability to issue securities under the registration statement, we now have remaining and available for issuance a total of approximately $200 million of equity securities and $250 million of subordinated debt securities.

As of February 2, 2010, we had received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under a new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities. We expect to file a registration statement with the SEC to register such securities as soon as practicable.

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 regulated and nonregulated 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). As of December 31, 2009, all three rating agencies maintained a stable outlook. None of our ratings are currently under review. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of adverse global financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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 independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2009. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2009, September 30, 2009 and December 31, 2008:

	December 31, 2009		September 30, 2009		December 31, 2008	
	(In thousands, except percentages)					
Short-term debt	$ 179,712	3.9%	$ 72,550	1.6%	$ 360,833	7.9%
Long-term debt	2,169,601	47.1%	2,169,531	49.1%	2,120,427	46.5%
Shareholders' equity	2,258,076	49.0%	2,176,761	49.3%	2,078,076	45.6%
Total	$4,607,389	100.0%	$4,418,842	100.0%	$4,559,336	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.0 percent at December 31, 2009, 50.7 percent at September 30, 2009 and 54.4 percent at December 31, 2008. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and, if necessary, access to the equity capital markets.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2009.

As we previously discussed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. During the quarter, we commenced negotiations to enter into a joint venture with a third party to develop the project. We expect such negotiations to be completed by the end of the second quarter of this fiscal year.

Risk Management Activities

We conduct risk management activities through our natural gas distribution, natural gas marketing and pipeline, storage and other segments. In our natural gas distribution segment, we use a combination of physical 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 and pipeline, storage and other segments, 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three months ended December 31, 2009 and 2008:

	Three Months Ended December 31	
	2009	2008
	(In thousands)	
Fair value of contracts at beginning of period	$(14,166)	$(63,677)
Contracts realized/settled	(21,029)	(53,766)
Fair value of new contracts	(947)	(4,282)
Other changes in value	18,672	70,411
Fair value of contracts at end of period	$(17,470)	$(51,314)

The fair value of our natural gas distribution segment's financial instruments at December 31, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2009				
	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	$(16,227)	$(1,243)	$—	$—	$(17,470)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(16,227)	$(1,243)	$—	$—	$(17,470)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the three months ended December 31, 2009 and 2008:

	Three Months Ended December 31	
	2009	2008
	(In thousands)	
Fair value of contracts at beginning of period	$26,698	$ 16,542
Contracts realized/settled	(2,212)	(20,247)
Fair value of new contracts	—	—
Other changes in value	7,820	(24,893)
Fair value of contracts at end of period	32,306	(28,598)
Netting of cash collateral	(1,315)	75,825
Cash collateral and fair value of contracts at period end	$30,991	$ 47,227

The fair value of our natural gas marketing segment's financial instruments at December 31, 2009 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2009				
	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	$22,055	$10,251	$—	$—	$32,306
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$22,055	$10,251	$—	$—	$32,306

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2009 and 2008, our total net periodic pension and other benefits cost was $12.7 million and $12.1 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2010 costs were determined using a September 30, 2009 measurement date. As of September 30, 2009, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of September 30, 2008, the measurement date for our fiscal 2009 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2010 pension and benefit costs to 5.52 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is mitigated by the fact that assets are "smoothed" for purposes of determining net periodic pension cost. Accordingly, asset gains and losses are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Accordingly, our fiscal 2010 pension and postretirement medical costs were materially the same as in fiscal 2009.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2010. Based upon this valuation, we expect we will be required to contribute less than $30 million to our pension plans by September 15, 2010. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $13 million to these plans during fiscal 2010.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage, natural gas marketing and pipeline, storage and other segments for the three-month periods ended December 31, 2009 and 2008.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended December 31	
	2009	2008
METERS IN SERVICE, end of period		
Residential	2,925,028	2,929,319
Commercial	271,713	273,590
Industrial	2,539	2,232
Public authority and other	9,251	9,236
Total meters	3,208,531	3,214,377
INVENTORY STORAGE BALANCE — Bcf	57.6	58.2
SALES VOLUMES — MMcf[(1)]		
Gas sales volumes		
Residential	60,546	54,208
Commercial	30,490	28,329
Industrial	5,319	5,400
Public authority and other	2,959	3,509
Total gas sales volumes	99,314	91,446
Transportation volumes	36,241	35,285
Total throughput	135,555	126,731
OPERATING REVENUES (000's)[(1)]		
Gas sales revenues		
Residential	$ 507,911	$ 647,100
Commercial	219,420	302,694
Industrial	31,033	50,155
Public authority and other	20,198	31,394
Total gas sales revenues	778,562	1,031,343
Transportation revenues	16,475	15,766
Other gas revenues	7,857	8,859
Total operating revenues	$ 802,894	$1,055,968
Average transportation revenue per Mcf	$ 0.45	$ 0.45
Average cost of gas per Mcf sold	$ 5.12	$ 8.28

See footnote following these tables.

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

	Three Months Ended December 31	
	2009	2008
CUSTOMERS, end of period		
Industrial	717	703
Municipal	63	59
Other	502	490
Total	1,282	1,252
INVENTORY STORAGE BALANCE — Bcf		
Natural gas marketing	19.2	15.8
Pipeline, storage and other	3.2	2.5
Total	22.4	18.3
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	157,773	192,172
NATURAL GAS MARKETING SALES VOLUMES — MMcf[(1)]	102,261	110,658
OPERATING REVENUES (000's)[(1)]		
Regulated transmission and storage	$ 46,860	$ 54,682
Natural gas marketing	544,271	787,495
Pipeline, storage and other	11,623	16,448
Total operating revenues	$602,754	$858,625

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the three months ended December 31, 2009, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2009 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods

specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the three months ended December 31, 2009, except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. ***Exhibits***

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

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President, Chief Financial Officer and Treasurer
(Duly authorized signatory)

Date: February 3, 2010

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.1	Revolving Credit Agreement (364 Day Facility), dated as of October 22, 2009, among Atmos Energy Corporation, the Lenders from time to time parties thereto, SunTrust Bank as Administrative Agent, Wells Fargo Bank, N.A. as Syndication Agent, and Bank of America, N.A. and U.S. Bank National Association as Co-Documentation Agents	Exhibit 10.1 to Form 8-K dated October 22, 2009 (File No. 1-10042)
10.2	Fourth Amended and Restated Credit Agreement, dated as of December 10, 2009 among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank and as a bank, Fortis Bank SA/NV, New York Branch, a bank organized under the laws of Belgium, as documentation agent, as an issuing bank and as a bank, Société Générale, as syndication agent, as an issuing bank and as a bank and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated December 10, 2009 (File No. 1-10042)
10.3	Second Amended and Restated Intercreditor Agreement, dated as of December 10, 2009 (as amended, supplemented and otherwise modified from time to time, the "Agreement"), among BNP PARIBAS, a bank organized under the laws of France, in its capacity as Collateral Agent (together with its successors and assigns in such capacity, the "Agent") for the Banks hereinafter referred to, and each bank and other financial institution which is now or hereafter a party to this Agreement in its capacity as a Bank and, as applicable, as a Swap Bank (collectively, the "Swap Banks") and as a Physical Trade Bank (collectively, the "Physical Trade Banks")	Exhibit 10.2 to Form 8-K dated December 10, 2009 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	

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

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2010

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).* Yes ☐ No ☐

* The registrant has not yet been phased into the interactive data requirements.

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

Number of shares outstanding of each of the issuer's classes of common stock, as of April 30, 2010.

Class	Shares Outstanding
No Par Value	93,147,184

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2010	September 30, 2009
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,295,260	$6,086,618
Less accumulated depreciation and amortization	1,704,785	1,647,515
Net property, plant and equipment	4,590,475	4,439,103
Current assets		
Cash and cash equivalents	231,153	111,203
Accounts receivable, net	546,356	232,806
Gas stored underground	208,589	352,728
Other current assets	121,261	132,203
Total current assets	1,107,359	828,940
Goodwill and intangible assets	739,750	740,064
Deferred charges and other assets	315,606	335,659
	$6,753,190	$6,343,766
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2010 — 93,146,535 shares; September 30, 2009 — 92,551,709 shares	$ 466	$ 463
Additional paid-in capital	1,809,331	1,791,129
Retained earnings	550,259	405,353
Accumulated other comprehensive loss	(21,213)	(20,184)
Shareholders' equity	2,338,843	2,176,761
Long-term debt	2,159,475	2,169,400
Total capitalization	4,498,318	4,346,161
Current liabilities		
Accounts payable and accrued liabilities	521,913	207,421
Other current liabilities	432,469	457,319
Short-term debt	—	72,550
Current maturities of long-term debt	10,131	131
Total current liabilities	964,513	737,421
Deferred income taxes	594,269	570,940
Regulatory cost of removal obligation	317,203	321,086
Deferred credits and other liabilities	378,887	368,158
	$6,753,190	$6,343,766

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2010	2009
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,365,988	$1,230,420
Regulated transmission and storage segment	55,181	59,234
Natural gas marketing segment	692,152	708,658
Pipeline, storage and other segment	9,050	12,272
Intersegment eliminations	(182,105)	(189,178)
	1,940,266	1,821,406
Purchased gas cost		
Natural gas distribution segment	980,603	863,340
Regulated transmission and storage segment	—	—
Natural gas marketing segment	685,672	685,114
Pipeline, storage and other segment	1,369	1,656
Intersegment eliminations	(181,699)	(188,755)
	1,485,945	1,361,355
Gross profit	454,321	460,051
Operating expenses		
Operation and maintenance	117,088	121,740
Depreciation and amortization	53,080	53,450
Taxes, other than income	59,613	58,314
Total operating expenses	229,781	233,504
Operating income	224,540	226,547
Miscellaneous income (expense)	49	(1,565)
Interest charges	39,582	35,533
Income before income taxes	185,007	189,449
Income tax expense	70,881	60,446
Net income	$ 114,126	$ 129,003
Basic net income per share	$ 1.22	$ 1.41
Diluted net income per share	$ 1.22	$ 1.40
Cash dividends per share	$ 0.335	$ 0.330
Weighted average shares outstanding:		
Basic	92,518	90,895
Diluted	92,853	91,192

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2010	2009
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,168,882	$2,286,388
Regulated transmission and storage segment	102,041	113,916
Natural gas marketing segment	1,236,423	1,496,153
Pipeline, storage and other segment	20,673	28,720
Intersegment eliminations	(294,901)	(387,439)
	3,233,118	3,537,738
Purchased gas cost		
Natural gas distribution segment	1,488,870	1,620,924
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,170,158	1,442,586
Pipeline, storage and other segment	3,002	5,559
Intersegment eliminations	(294,082)	(386,594)
	2,367,948	2,682,475
Gross profit	865,170	855,263
Operating expenses		
Operation and maintenance	240,950	254,417
Depreciation and amortization	106,919	106,576
Taxes, other than income	102,165	102,451
Asset impairments	—	2,078
Total operating expenses	450,034	465,522
Operating income	415,136	389,741
Miscellaneous expense	(220)	(1,866)
Interest charges	78,290	74,524
Income before income taxes	336,626	313,351
Income tax expense	129,170	108,385
Net income	$ 207,456	$ 204,966
Basic net income per share	$ 2.22	$ 2.24
Diluted net income per share	$ 2.22	$ 2.23
Cash dividends per share	$ 0.670	$ 0.660
Weighted average shares outstanding:		
Basic	92,336	90,637
Diluted	92,681	90,935

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2010	2009
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 207,456	$ 204,966
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	106,919	106,576
Charged to other accounts	96	21
Deferred income taxes	44,097	97,892
Other	11,759	13,634
Net assets/liabilities from risk management activities	1,234	5,810
Net change in operating assets and liabilities	111,897	185,723
Net cash provided by operating activities	483,458	614,622
Cash Flows From Investing Activities		
Capital expenditures	(232,629)	(221,330)
Other, net	(946)	(3,925)
Net cash used in investing activities	(233,575)	(225,255)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(75,907)	(353,468)
Net proceeds from issuance of long-term debt	—	446,188
Settlement of Treasury lock agreement	—	1,938
Repayment of long-term debt	(66)	(625)
Cash dividends paid	(62,550)	(60,446)
Issuance of common stock	8,590	12,414
Net cash provided by (used in) financing activities	(129,933)	46,001
Net increase in cash and cash equivalents	119,950	435,368
Cash and cash equivalents at beginning of period	111,203	46,717
Cash and cash equivalents at end of period	$ 231,153	$ 482,085

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2010

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over 3 million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our natural gas distribution and regulated pipeline and storage businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast and include our natural gas marketing operations and pipeline, storage and other operations. These businesses are operated through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH), which is wholly owned by the Company and based in Houston, Texas. Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers and natural gas transportation and storage services to certain of our natural gas distribution divisions and third parties.

We operate the Company through the following four segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes our regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment*, which is comprised of our nonregulated natural gas gathering, transmission and storage services.

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2010 are not indicative of our results of operations for the full 2010 fiscal year, which ends September 30, 2010. We have evaluated subsequent events from the March 31, 2010 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC).

No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009.

During the second quarter of fiscal 2010, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

The Company adopted an accounting standard related to fair value disclosures effective January 1, 2010. Effective October 1, 2009, the Company adopted accounting standards related to the measurement of liabilities at fair value, fair value measurements of plan assets of a defined benefit pension or other postretirement plan, the determination of participating securities in the basic earnings per share calculation, business combination accounting and the accounting and reporting for minority interests. Except as indicated below, the adoption of these standards did not have a material impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the six months ended March 31, 2010.

Fair value disclosures — The Financial Accounting Standards Board (FASB) issued guidance that requires new disclosures surrounding fair value measurements to enhance the existing disclosure requirements including 1) information about transfers in and out of Level 1 and Level 2 fair value measurements as well as a detailed reconciliation of activity in Level 3 fair value measurements; 2) a more detailed level of disaggregation for each class of assets and liabilities; and 3) a requirement to disclose information about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements that fall in either Level 2 or Level 3. The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures related to the detailed reconciliation of Level 3 fair value measurements, which are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. As a result of adopting this standard, we added a disclosure about the valuation techniques and inputs we used to measure fair value for our Level 2 recurring and nonrecurring fair value measurements as of March 31, 2010 which is included in Note 4. As of March 31, 2010, we did not have any Level 3 fair value measurements.

Measurement of liabilities at fair value — When a quoted price in an active market for an identical liability is not available, we will be required to measure fair value using a valuation technique that uses quoted prices of similar liabilities, quoted prices of identical or similar liabilities when traded as assets, or another valuation technique that is consistent with U.S. generally accepted accounting principles (GAAP), such as the income or market approach. Additionally, when estimating the fair value of a liability, we will not be required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents our transfer of the liability.

Fair value measurements of plan assets of a defined benefit pension or other postretirement plan — The FASB issued guidance which requires employers to disclose annually information about fair value measurements of the assets of a defined benefit pension or other postretirement plan in a manner similar to the requirements established for financial and non-financial assets. The objectives of the required disclosures are to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure fair value of plan assets and significant concentrations of risk within plan assets. These disclosures will appear in our Form 10-K for the year ending September 30, 2010.

The determination of participating securities in the basic earnings per share calculation — The FASB issued guidance related to determining whether instruments granted in share-based payment transactions are

considered participating securities. The FASB determined that non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents are participating securities and, as a result, companies with these types of participating securities must use the two-class method to compute earnings per share. Based on this guidance, the Company is required to calculate earnings per share using the two-class method and will include non-vested restricted stock and restricted stock units for which vesting is only predicated upon the passage of time in the basic earnings per share calculation. Non-vested restricted stock and restricted stock units for which vesting is predicated, in part upon the achievement of specified performance targets, continue to be excluded from the calculation of earnings per share. Although the provisions of this standard were effective for us as of October 1, 2009, prior-period earnings per share data must be recalculated and adjusted accordingly. The calculation of basic and diluted earnings per share pursuant to the two-class method is presented in Note 6. The application of the two-class method resulted in the following changes to basic and diluted earnings per share for the three and six months ended March 31, 2009.

	Three Months Ended March 31, 2009	Six Months Ended March 31, 2009
	(In thousands, except per share amounts)	
Basic Earnings Per Share		
Basic EPS — as previously reported	$ 1.42	$ 2.26
Basic EPS — as adjusted	$ 1.41	$ 2.24
Weighted average shares outstanding — as previously reported	90,895	90,637
Weighted average shares outstanding — as adjusted	90,895	90,637
Diluted Earnings Per Share		
Diluted EPS — as previously reported	$ 1.41	$ 2.24
Diluted EPS — as adjusted	$ 1.40	$ 2.23
Weighted average shares outstanding — as previously reported	91,567	91,311
Weighted average shares outstanding — as adjusted	91,192	90,935

Business combination accounting — This new pronouncement establishes new principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. This update significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under the new guidelines, changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact current period income tax expense. The provisions of this standard will apply to any acquisitions we complete after October 1, 2009.

Accounting and reporting for minority interests — In December 2007, the FASB issued guidance related to the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changes the accounting for transactions with minority interest holders. As of March 31, 2010, Atmos Energy did not have any transactions with minority interest holders.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will

be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of March 31, 2010 and September 30, 2009 included the following:

	March 31, 2010	September 30, 2009
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$192,291	$197,743
Merger and integration costs, net	6,938	7,161
Deferred gas costs	67,132	22,233
Environmental costs	913	866
Rate case costs	3,554	5,923
Deferred franchise fees	507	10,014
Deferred income taxes, net	639	639
Other	5,707	6,218
	$277,681	$250,797
Regulatory liabilities:		
Deferred gas costs	$ 20,583	$110,754
Deferred franchise fees	4,730	—
Regulatory cost of removal obligation	340,869	335,428
Other	6,358	7,960
	$372,540	$454,142

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

The following table presents the components of comprehensive income, net of related tax, for the three-month and six-month periods ended March 31, 2010 and 2009:

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
	(In thousands)			
Net income	$114,126	$129,003	$207,456	$204,966
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $408 and $(429) for the three months ended March 31, 2010 and 2009 and of $798 and $(3,759) for the six months ended March 31, 2010 and 2009	695	(862)	1,359	(6,295)
Other than temporary impairment of investments, net of tax expense of $790 for the six months ended March 31, 2009	—	—	—	1,288
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $248 and $1,353 for the three months ended March 31, 2010 and 2009 and $496 and $1,835 for the six months ended March 31, 2010 and 2009	421	1,854	843	2,641
Net unrealized losses on commodity hedging transactions, net of tax benefit of $6,321 and $7,524 for the three months ended March 31, 2010 and 2009 and $2,067 and $21,341 for the six months ended March 31, 2010 and 2009	(9,885)	(9,771)	(3,231)	(32,315)
Comprehensive income	$105,357	$120,224	$206,427	$170,285

Accumulated other comprehensive loss, net of tax, as of March 31, 2010 and September 30, 2009 consisted of the following unrealized gains (losses):

	March 31, 2010	September 30, 2009
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 3,819	$ 2,460
Treasury lock agreements	(6,655)	(7,498)
Cash flow hedges	(18,377)	(15,146)
	$(21,213)	$(20,184)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. However, our pipeline, storage and other segment uses financial instruments acquired from Atmos Energy Marketing, LLC (AEM) on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial

instruments are reported in the natural gas marketing segment. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2009-2010 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 29 percent, or 26.9 Bcf of the planned winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

Our natural gas marketing segment, through AEM, 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.

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap

contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 52 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments.

Also, in our natural gas marketing segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on March 31, 2010, AEH had net open positions (including existing storage) of 0.8 Bcf.

Interest Rate Risk Management Activities

Currently, we are not managing interest rate risk with financial instruments. However, in prior years, we periodically managed interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a cumulative net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts of these Treasury locks will be recognized by the end of fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of March 31, 2010, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of March 31, 2010, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other
			Quantity (MMcf)	
Commodity contracts	Fair Value	—	(19,135)	(1,010)
	Cash Flow	—	24,905	(700)
	Not designated	14,800	59,697	380
		14,800	65,467	(1,330)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of March 31, 2010 and September 30, 2009. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $7.2 million and $11.7 million of cash held on deposit in margin accounts as of March 31, 2010 and September 30, 2009 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
March 31, 2010				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 49,314	$ 49,314
Noncurrent commodity contracts	Deferred charges and other assets	—	5,899	5,899
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(51,648)	(51,648)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(4,893)	(4,893)
Total		—	(1,328)	(1,328)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	281	40,314	40,595
Noncurrent commodity contracts	Deferred charges and other assets	—	4,692	4,692
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(22,016)	(28,812)	(50,828)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(639)	(639)
Total		(21,735)	15,555	(6,180)
Total Financial Instruments		$(21,735)	$ 14,227	$ (7,508)

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
September 30, 2009				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 53,526	$ 53,526
Noncurrent commodity contracts	Deferred charges and other assets	—	6,800	6,800
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(47,146)	(47,146)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(999)	(999)
Total		—	12,181	12,181
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	4,395	27,559	31,954
Noncurrent commodity contracts	Deferred charges and other assets	1,620	7,964	9,584
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(20,181)	(19,657)	(39,838)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,349)	(1,349)
Total		(14,166)	14,517	351
Total Financial Instruments		$(14,166)	$ 26,698	$ 12,532

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our condensed consolidated income statement, by operating segment, as applicable, for the three and six months ended March 31, 2010 and 2009.

Hedge ineffectiveness for our natural gas marketing and pipeline storage and other segments is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended March 31, 2010 and 2009 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(4.9) million and $4.2 million. For the six months ended March 31, 2010 and 2009 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $40.4 million and $24.6 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2010 and 2009 is presented below.

	Three Months Ended March 31, 2010		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 30,926	$ 2,535	$ 33,461
Fair value adjustment for natural gas inventory designated as the hedged item	(34,969)	(2,697)	(37,666)
Total impact on revenue	$ (4,043)	$ (162)	$ (4,205)
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (512)	$ —	$ (512)
Timing ineffectiveness	(3,531)	(162)	(3,693)
	$ (4,043)	$ (162)	$ (4,205)

	Three Months Ended March 31, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 19,870	$2,105	$ 21,975
Fair value adjustment for natural gas inventory designated as the hedged item	(18,562)	(437)	(18,999)
Total impact on revenue	$ 1,308	$1,668	$ 2,976
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 2,327	$ —	$ 2,327
Timing ineffectiveness	(1,019)	1,668	649
	$ 1,308	$1,668	$ 2,976

	Six Months Ended March 31, 2010		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$28,743	$2,078	$30,821
Fair value adjustment for natural gas inventory designated as the hedged item	8,343	3,174	11,517
Total impact on revenue	$37,086	$5,252	$42,338
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (449)	$ —	$ (449)
Timing ineffectiveness	37,535	5,252	42,787
	$37,086	$5,252	$42,338

	Six Months Ended March 31, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)		
Commodity contracts	$ 45,553	$ 6,044	$ 51,597
Fair value adjustment for natural gas inventory designated as the hedged item	(30,422)	(1,990)	(32,412)
Total impact on revenue	$ 15,131	$ 4,054	$ 19,185
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 4,279	$ —	$ 4,279
Timing ineffectiveness	10,852	4,054	14,906
	$ 15,131	$ 4,054	$ 19,185

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot to forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 2010 and 2009 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized or will realize when the underlying physical and financial transactions are settled.

	Three Months Ended March 31, 2010			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)		
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(10,685)	$2,129	$(8,556)
Loss arising from ineffective portion of commodity contracts	—	(739)	—	(739)
Total impact on revenue	—	(11,424)	2,129	(9,295)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(669)	—	—	(669)
Total Impact from Cash Flow Hedges	$(669)	$(11,424)	$2,129	$(9,964)

	Three Months Ended March 31, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(48,585)	$16,170	$(32,415)
Gain arising from ineffective portion of commodity contracts	—	1,180	—	1,180
Total impact on revenue	—	(47,405)	16,170	(31,235)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,269)	—	—	(1,269)
Total Impact from Cash Flow Hedges	$(1,269)	$(47,405)	$16,170	$(32,504)

	Six Months Ended March 31, 2010			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(34,556)	$2,883	$(31,673)
Loss arising from ineffective portion of commodity contracts	—	(1,957)	—	(1,957)
Total impact on revenue	—	(36,513)	2,883	(33,630)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,339)	—	—	(1,339)
Total Impact from Cash Flow Hedges	$(1,339)	$(36,513)	$2,883	$(34,969)

	Six Months Ended March 31, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(76,829)	$24,139	$(52,690)
Gain arising from ineffective portion of commodity contracts	—	5,372	—	5,372
Total impact on revenue	—	(71,457)	24,139	(47,318)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,538)	—	—	(2,538)
Total Impact from Cash Flow Hedges	$(2,538)	$(71,457)	$24,139	$(49,856)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 2010 and 2009. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ —	$ 1,221	$ —	$ 1,221
Forward commodity contracts	(15,104)	(29,544)	(22,551)	(64,659)
Recognition of losses in earnings due to settlements:				
Treasury lock agreements	421	633	843	1,420
Forward commodity contracts	5,219	19,773	19,320	32,344
Total other comprehensive loss from hedging, net of tax[(1)]	$ (9,464)	$ (7,917)	$ (2,388)	$(29,674)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Deferred losses recorded in AOCI associated with our treasury lock agreements are recognized into earnings as they are amortized, while deferred losses associated with commodity contracts are recognized into earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2010:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,687)	$(14,830)	$(16,517)
Thereafter	(4,968)	(3,547)	(8,515)
Total[(1)]	$(6,655)	$(18,377)	$(25,032)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three and six months ended March 31, 2010 and 2009 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact to our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related

costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
	(In thousands)			
Natural gas marketing commodity contracts	$(1,811)	$10,593	$12,464	$6,761
Pipeline, storage and other commodity contracts	(1,175)	183	(168)	100
Total impact on revenue	$(2,986)	$10,776	$12,296	$6,861

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the three and six months ended March 31, 2010, there were no changes in these methods.

Effective October 1, 2009, the authoritative guidance related to nonrecurring fair value measurements became effective for us with respect to asset retirement obligations, most nonfinancial assets and liabilities that may be acquired in a business combination and impairment analyses performed for nonfinancial assets. The adoption of the FASB's fair value guidance for the reporting of these nonrecurring fair value measurements did not have a material impact on our financial position, results of operations or cash flows for the three and six months ended March 31, 2010.

Although fair value measurements also apply to the valuation of our pension and post-retirement plan assets, the current fair value disclosure requirements are not applicable to our pension and post-retirement plan assets. Accordingly, these plan assets are not included in the tabular disclosures below. However, similar disclosures about fair value measurements for our pension and post-retirement plan assets will appear in our Form 10-K for the year ending September 30, 2010.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2010. Assets

and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	March 31, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 281	$ —	$ —	$ 281
Natural gas marketing segment	31,459	68,760	—	(72,289)	27,930
Total financial instruments	31,459	69,041	—	(72,289)	28,211
Hedged portion of gas stored underground					
Natural gas marketing segment	73,655	—	—	—	73,655
Pipeline, storage and other segment[3]	3,844	—	—	—	3,844
Total gas stored underground	77,499	—	—	—	77,499
Available-for-sale securities	42,558	—	—	—	42,558
Total assets	$151,516	$69,041	$ —	$(72,289)	$148,268
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$22,016	$ —	$ —	$ 22,016
Natural gas marketing segment	53,387	32,605	—	(79,488)	6,504
Total liabilities	$ 53,387	$54,621	$ —	$(79,488)	$ 28,520

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and authoritative accounting literature. In addition, as of March 31, 2010, we had $7.2 million of cash held in margin accounts used to collateralize certain financial instruments which has been reflected as a financial instrument asset.

(3) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of March 31, 2010:

	March 31, 2010 (In thousands)
Carrying Amount	$2,172,761
Fair Value	$2,364,093

5. Debt

Long-term debt

Long-term debt at March 31, 2010 and September 30, 2009 consisted of the following:

	March 31, 2010	September 30, 2009
	(In thousands)	
Unsecured 7.375% Senior Notes, due May 2011	$ 350,000	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 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
Rental property term note due in installments through 2013	458	524
Total long-term debt	2,172,761	2,172,827
Less:		
Original issue discount on unsecured senior notes and debentures	(3,155)	(3,296)
Current maturities	(10,131)	(131)
	$2,159,475	$2,169,400

As noted above, our Series A, 1995-2, 6.27% medium term note will mature in December 2010; accordingly, it has been classified within the current maturities of long-term debt.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide

approximately $1.2 billion of working capital funding. At March 31, 2010, there were no short-term debt borrowings outstanding. At September 30, 2009, there was a total of $72.6 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $800 million of working capital funding. The first facility is a five-year $566.7 million unsecured facility, expiring December 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At March 31, 2010, there were no borrowings under this facility nor was there any commercial paper outstanding.

The second facility is a $200 million unsecured 364-day facility that expires October 22, 2010. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.75 percent to 3.00 percent, based on the Company's credit ratings. At March 31, 2010, there were no borrowings outstanding under this facility.

The third facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At March 31, 2010, there were no borrowings outstanding under this facility. This facility expired on March 31, 2010 and was replaced with a $25 million unsecured facility effective April 1, 2010 that also bears interest at a daily negotiated rate.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2010, our total-debt-to-total-capitalization ratio, as defined, was 51 percent. In addition, both the interest margin over the Eurodollar rate and the fees that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, the Company has a $200 million intercompany revolving credit facility provided by AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility, (ii) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the 364-day revolving credit facility or (iii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2010. There was $20.5 million outstanding under this facility at March 31, 2010.

Nonregulated Operations

On December 10, 2009, AEM and the participating banks amended and restated AEM's $450 million committed revolving credit facility extending it to December 9, 2010.

AEM uses this facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar

loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; and (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent plus 0.50 percent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; and (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 2.250 percent to 2.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $17 million to $27 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At March 31, 2010, there were no borrowings outstanding under this credit facility. However, at March 31, 2010, AEM letters of credit totaling $42.0 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 $258.0 million at March 31, 2010.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At March 31, 2010, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.96 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $75 million to $112.5 million. As defined in the financial covenants, at March 31, 2010, AEM's net working capital was $240.4 million and its tangible net worth was $254.4 million.

To supplement borrowings under this facility, AEM has a $300 million intercompany demand credit facility with AEH, which bears interest at the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Amounts outstanding under this facility are subordinated to AEM's committed credit facility. There was $40.0 million outstanding under this facility at March 31, 2010.

Finally, AEH has a $200 million intercompany demand credit facility with AEC, which bears interest at greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved the new facility through December 31, 2010. There were no borrowings outstanding under this facility at March 31, 2010.

Shelf Registration

On March 31, 2010, we filed a registration statement with the SEC to issue, from time to time, up to $1.3 billion in common stock and/or debt securities available for issuance.

We had already received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under the new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of March 31, 2010. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

As discussed in Note 2, since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share as of October 1, 2009. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. The presentation of earnings per share for previously reported periods has been adjusted to reflect the retrospective adoption of this standard. Basic and diluted earnings per share for the three and six months ended March 31, 2010 and 2009 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
	(In thousands, except per share amounts)			
Basic Earnings Per Share				
Net income	$114,126	$129,003	$207,456	$204,966
Less: Income allocated to participating securities	1,142	1,183	2,088	1,817
Net income available to common shareholders	$112,984	$127,820	$205,368	$203,149
Basic weighted average shares outstanding	92,518	90,895	92,336	90,637
Net income per share — Basic	$ 1.22	$ 1.41	$ 2.22	$ 2.24
Diluted Earnings Per Share				
Net income available to common shareholders	$112,984	$127,820	$205,368	$203,149
Effect of dilutive stock options and other shares	3	3	5	4
Net income available to common shareholders	$112,987	$127,823	$205,373	$203,153
Basic weighted average shares outstanding	92,518	90,895	92,336	90,637
Additional dilutive stock options and other shares	335	297	345	298
Diluted weighted average shares outstanding	92,853	91,192	92,681	90,935
Net income per share — Diluted	$ 1.22	$ 1.40	$ 2.22	$ 2.23

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2010 as their exercise price was less than the average market price of the common stock during that period. There were approximately 260,000 out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2009.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and six months ended March 31, 2010 and 2009 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,994	$ 3,703	$3,359	$2,946
Interest cost	6,523	7,554	3,017	3,520
Expected return on assets	(6,320)	(6,238)	(615)	(573)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(194)	(183)	(375)	—
Amortization of actuarial loss	2,823	955	94	—
Net periodic pension cost	$ 6,826	$ 5,791	$5,858	$6,271

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 7,987	$ 7,406	$ 6,719	$ 5,892
Interest cost	13,047	15,108	6,035	7,040
Expected return on assets	(12,640)	(12,476)	(1,230)	(1,146)
Amortization of transition asset	—	—	756	756
Amortization of prior service cost	(387)	(366)	(750)	—
Amortization of actuarial loss	5,645	1,910	187	—
Net periodic pension cost	$ 13,652	$ 11,582	$11,717	$12,542

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2010 and 2009 are as follows:

	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
Discount rate	5.52%	7.57%	5.52%	7.57%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2010. Based upon this valuation, we expect we will be required to contribute less than $5 million to our pension plans by September 15, 2010.

We contributed $5.9 million to our other post-retirement benefit plans during the six months ended March 31, 2010. We expect to contribute a total of approximately $12 million to these plans during fiscal 2010.

For our Supplemental Executive Retirement Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of March 31, 2010:				
Domestic equity mutual funds	$29,306	$5,132	$—	$34,438
Foreign equity mutual funds	4,753	927	—	5,680
Money market funds	2,440	—	—	2,440
	$36,499	$6,059	$—	$42,558
As of September 30, 2009:				
Domestic equity mutual funds	$26,012	$3,012	$—	$29,024
Foreign equity mutual funds	4,047	893	—	4,940
Money market funds	7,735	—	—	7,735
	$37,794	$3,905	$—	$41,699

During the six months ended March 31, 2009, we recorded a $2.1 million noncash charge to impair certain available-for-sale investments due to deterioration of the market and the uncertainty of a full recovery. We did not maintain any investments that are in an unrealized loss position at March 31, 2010.

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 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2010. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At March 31, 2010, AEM was committed to purchase 98.7 Bcf within one year, 8.1 Bcf within one to three years and 2.5 Bcf after three years under indexed contracts. AEM is committed to purchase 2.0 Bcf within one year, 0.9 Bcf within one to three years and 0.1 Bcf after three years under fixed price contracts with prices ranging from $3.64 to $6.36 per Mcf. Purchases under these contracts totaled $538.6 million and $431.5 million for the three months ended March 31, 2010 and 2009 and $892.7 million and $959.0 million for the six months ended March 31, 2010 and 2009.

Our natural gas distribution divisions, except for our 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 and fixed prices. The estimated commitments under these contracts as of March 31, 2010 are as follows (in thousands):

2010	$ 78,356
2011	150,999
2012	86,504
2013	6,564
2014	2,273
Thereafter	—
	$324,696

Our natural gas marketing and pipeline, storage and other segments maintain long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. There were no material changes to the estimated storage and transportation fees for the six months ended March 31, 2010.

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

After responding to two sets of data requests received from the Commission, the Commission agreed to allow us to conduct our own internal investigation into compliance with the Commission's rules. We have

completed our internal investigation and submitted the results to the Commission. During our investigation, we identified certain non-compliant transactions, and we continue to fully cooperate with the Commission as we work to resolve this matter. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

As of March 31, 2010, rate cases were in progress in our Kansas, Kentucky and Missouri service areas and annual rate filing mechanisms were in progress in our Mid-Tex service area. In addition, there were GRIP filings in progress in our Atmos Pipeline — Texas, Mid-Tex and West Texas divisions along with other rate activity in our Georgia and Louisiana service areas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the six months ended March 31, 2010, there were no material changes in our concentration of credit risk.

10. Segment Information

As discussed in Note 1 above, we operate the Company through the following four segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which includes our nonregulated natural gas gathering transmission and storage services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in varying regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2009. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six month periods ended March 31, 2010 and 2009 by segment are presented in the following tables:

	Three Months Ended March 31, 2010					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,365,736	$21,643	$545,985	$6,902	$ —	$1,940,266
Intersegment revenues	252	33,538	146,167	2,148	(182,105)	—
	1,365,988	55,181	692,152	9,050	(182,105)	1,940,266
Purchased gas cost	980,603	—	685,672	1,369	(181,699)	1,485,945
Gross profit	385,385	55,181	6,480	7,681	(406)	454,321
Operating expenses						
Operation and maintenance	87,542	20,248	6,531	3,173	(406)	117,088
Depreciation and amortization	46,748	5,282	424	626	—	53,080
Taxes, other than income	55,531	2,949	747	386	—	59,613
Total operating expenses	189,821	28,479	7,702	4,185	(406)	229,781
Operating income (loss)	195,564	26,702	(1,222)	3,496	—	224,540
Miscellaneous income (expense)	776	(20)	287	980	(1,974)	49
Interest charges	29,256	7,954	2,820	1,526	(1,974)	39,582
Income (loss) before income taxes	167,084	18,728	(3,755)	2,950	—	185,007
Income tax expense (benefit)	64,353	6,658	(1,313)	1,183	—	70,881
Net income (loss)	$ 102,731	$12,070	$ (2,442)	$1,767	$ —	$ 114,126
Capital expenditures	$ 95,765	$20,063	$ 47	$1,315	$ —	$ 117,190

	Three Months Ended March 31, 2009					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,230,196	$32,097	$549,136	$ 9,977	$ —	$1,821,406
Intersegment revenues	224	27,137	159,522	2,295	(189,178)	—
	1,230,420	59,234	708,658	12,272	(189,178)	1,821,406
Purchased gas cost	863,340	—	685,114	1,656	(188,755)	1,361,355
Gross profit	367,080	59,234	23,544	10,616	(423)	460,051
Operating expenses						
Operation and maintenance	90,710	17,327	12,323	1,889	(509)	121,740
Depreciation and amortization	47,541	5,006	396	507	—	53,450
Taxes, other than income	55,101	2,572	446	195	—	58,314
Total operating expenses	193,352	24,905	13,165	2,591	(509)	233,504
Operating income	173,728	34,329	10,379	8,025	86	226,547
Miscellaneous income (expense)	835	283	118	2,060	(4,861)	(1,565)
Interest charges	28,821	7,349	3,461	677	(4,775)	35,533
Income before income taxes	145,742	27,263	7,036	9,408	—	189,449
Income tax expense	44,166	7,798	3,688	4,794	—	60,446
Net income	$ 101,576	$19,465	$ 3,348	$ 4,614	$ —	$ 129,003
Capital expenditures	$ 84,618	$28,303	$ 88	$ 954	$ —	$ 113,963

	Six Months Ended March 31, 2010					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,168,422	$ 41,485	$1,006,806	$16,405	$ —	$3,233,118
Intersegment revenues	460	60,556	229,617	4,268	(294,901)	—
	2,168,882	102,041	1,236,423	20,673	(294,901)	3,233,118
Purchased gas cost	1,488,870	—	1,170,158	3,002	(294,082)	2,367,948
Gross profit	680,012	102,041	66,265	17,671	(819)	865,170
Operating expenses						
Operation and maintenance	183,575	37,827	15,286	5,081	(819)	240,950
Depreciation and amortization	94,605	10,224	835	1,255	—	106,919
Taxes, other than income	93,521	6,216	1,682	746	—	102,165
Total operating expenses	371,701	54,267	17,803	7,082	(819)	450,034
Operating income	308,311	47,774	48,462	10,589	—	415,136
Miscellaneous income (expense)	1,433	23	495	1,433	(3,604)	(220)
Interest charges	58,934	15,922	5,198	1,840	(3,604)	78,290
Income before income taxes	250,810	31,875	43,759	10,182	—	336,626
Income tax expense	96,631	11,351	17,189	3,999	—	129,170
Net income	$ 154,179	$ 20,524	$ 26,570	$ 6,183	$ —	$ 207,456
Capital expenditures	$ 196,227	$ 33,822	$ 453	$ 2,127	$ —	$ 232,629

	Six Months Ended March 31, 2009					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,285,968	$ 62,319	$1,165,980	$23,471	$ —	$3,537,738
Intersegment revenues	420	51,597	330,173	5,249	(387,439)	—
	2,286,388	113,916	1,496,153	28,720	(387,439)	3,537,738
Purchased gas cost	1,620,924	—	1,442,586	5,559	(386,594)	2,682,475
Gross profit	665,464	113,916	53,567	23,161	(845)	855,263
Operating expenses						
Operation and maintenance	186,928	44,664	20,783	3,059	(1,017)	254,417
Depreciation and amortization	94,680	9,961	797	1,138	—	106,576
Taxes, other than income	95,847	5,360	1,039	205	—	102,451
Asset impairments	1,776	232	56	14	—	2,078
Total operating expenses	379,231	60,217	22,675	4,416	(1,017)	465,522
Operating income	286,233	53,699	30,892	18,745	172	389,741
Miscellaneous income (expense)	3,956	1,098	419	4,221	(11,560)	(1,866)
Interest charges	61,708	15,428	7,363	1,413	(11,388)	74,524
Income before income taxes	228,481	39,369	23,948	21,553	—	313,351
Income tax expense	76,772	12,243	10,025	9,345	—	108,385
Net income	$ 151,709	$ 27,126	$ 13,923	$12,208	$ —	$ 204,966
Capital expenditures	$ 173,621	$ 33,363	$ 117	$14,229	$ —	$ 221,330

Balance sheet information at March 31, 2010 and September 30, 2009 by segment is presented in the following tables:

	March 31, 2010					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,811,548	$697,167	$ 7,229	$ 74,531	$ —	$4,590,475
Investment in subsidiaries	597,982	—	(2,096)	—	(595,886)	—
Current assets						
Cash and cash equivalents	53,441	—	173,340	4,372	—	231,153
Assets from risk management activities	281	—	19,017	833	(833)	19,298
Other current assets	571,092	14,726	278,909	71,287	(79,106)	856,908
Intercompany receivables	507,490	—	—	176,488	(683,978)	—
Total current assets	1,132,304	14,726	471,266	252,980	(763,917)	1,107,359
Intangible assets	—	—	1,147	—	—	1,147
Goodwill	571,592	132,300	24,282	10,429	—	738,603
Noncurrent assets from risk management activities	—	—	8,913	—	—	8,913
Deferred charges and other assets	280,265	8,701	1,164	16,563	—	306,693
	$6,393,691	$852,894	$511,905	$354,503	$(1,359,803)	$6,753,190
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,338,843	$191,724	$107,420	$298,838	$ (597,982)	$2,338,843
Long-term debt	2,159,148	—	—	327	—	2,159,475
Total capitalization	4,497,991	191,724	107,420	299,165	(597,982)	4,498,318
Current liabilities						
Current maturities of long-term debt	10,000	—	—	131	—	10,131
Short-term debt	20,475	—	40,000	—	(60,475)	—
Liabilities from risk management activities	22,016	—	3,483	—	(833)	24,666
Other current liabilities	657,020	7,961	239,894	41,376	(16,535)	929,716
Intercompany payables	—	555,141	128,837	—	(683,978)	—
Total current liabilities	709,511	563,102	412,214	41,507	(761,821)	964,513
Deferred income taxes	501,447	93,550	(12,277)	11,549	—	594,269
Noncurrent liabilities from risk management activities	—	—	3,854	—	—	3,854
Regulatory cost of removal obligation	317,203	—	—	—	—	317,203
Deferred credits and other liabilities	367,539	4,518	694	2,282	—	375,033
	$6,393,691	$852,894	$511,905	$354,503	$(1,359,803)	$6,753,190

	September 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,703,471	$672,829	$ 7,112	$ 55,691	$ —	$4,439,103
Investment in subsidiaries	547,936	—	(2,096)	—	(545,840)	—
Current assets						
Cash and cash equivalents	23,655	—	87,266	282	—	111,203
Assets from risk management activities	4,395	—	27,424	2,765	(2,941)	31,643
Other current assets	499,155	17,017	157,846	112,551	(100,475)	686,094
Intercompany receivables	552,408	—	—	128,104	(680,512)	—
Total current assets	1,079,613	17,017	272,536	243,702	(783,928)	828,940
Intangible assets	—	—	1,461	—	—	1,461
Goodwill	571,592	132,300	24,282	10,429	—	738,603
Noncurrent assets from risk management activities	1,620	—	12,415	6	(6)	14,035
Deferred charges and other assets	290,327	11,932	1,065	18,300	—	321,624
	$6,194,559	$834,078	$316,775	$328,128	$(1,329,774)	$6,343,766
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,176,761	$171,200	$ 83,354	$293,382	$ (547,936)	$2,176,761
Long-term debt	2,169,007	—	—	393	—	2,169,400
Total capitalization	4,345,768	171,200	83,354	293,775	(547,936)	4,346,161
Current liabilities						
Current maturities of long-term debt	—	—	—	131	—	131
Short-term debt	158,942	—	—	—	(86,392)	72,550
Liabilities from risk management activities	20,181	—	4,060	182	(2,941)	21,482
Other current liabilities	510,749	9,251	116,078	19,167	(11,987)	643,258
Intercompany payables	—	557,190	123,322	—	(680,512)	—
Total current liabilities	689,872	566,441	243,460	19,480	(781,832)	737,421
Deferred income taxes	477,352	92,250	(10,675)	12,013	—	570,940
Noncurrent liabilities from risk management activities	—	—	6	—	(6)	—
Regulatory cost of removal obligation	321,086	—	—	—	—	321,086
Deferred credits and other liabilities	360,481	4,187	630	2,860	—	368,158
	$6,194,559	$834,078	$316,775	$328,128	$(1,329,774)	$6,343,766

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of March 31, 2010, the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2010 and 2009, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2010 and 2009. 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, 2009, 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, 2009, 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, 2009, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
May 6, 2010

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, 2009.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties, which are discussed in more detail in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business; natural disasters, terrorist activities or other events; and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over 3 million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

We operate the Company through the following four segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment*, which is comprised of our nonregulated natural gas gathering, transmission and storage services.

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, the 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 fiscal year ended September 30, 2009 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the six months ended March 31, 2010.

RESULTS OF OPERATIONS

The second quarter is our most important earnings quarter, where historically, we have earned about 64 percent of our annual net income. For the three months ended March 31, 2010, we reported net income of $114.1 million, or $1.22 per diluted share compared with net income of $129.0 million, or $1.40 per diluted share in the prior-year quarter. During the three months ended March 31, 2010, we experienced a 26 percent increase in consolidated distribution throughput due to colder weather in most of our service areas, which was partially offset by a 20 percent decrease in consolidated throughput in our regulated transmission and storage segment due to reduced demand and basis spreads. In addition, net income for the second quarter includes the positive impact of a state sales tax refund of $4.5 million which contributed $0.05 per diluted share. The results of our nonregulated operations also include noncash, unrealized net losses of $25.5 million, or ($0.27) per diluted share recognized during the quarter.

We reported net income of $207.5 million, or $2.22 per diluted share for the six months ended March 31, 2010 compared with net income of $205.0 million, or $2.23 per diluted share in the prior-year period. Regulated operations contributed 84 percent of our net income during this period with our nonregulated operations contributing the remaining 16 percent. The primary driver in the year-over-year increase in net income was due to our natural gas marketing segment experiencing a significant increase in unrealized margins. The favorable movement in our unrealized margins was primarily the result of the period-over-period timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

During the six months ended March 31, 2010, colder-than-normal-weather during the current year and recent improvements in rate designs in our natural gas distribution segment partially offset the decline in demand for natural gas, which contributed to a 25 percent year-over-year decrease in consolidated throughput in our regulated transmission and storage segment and a three percent year-over-year decrease in consolidated sales volumes in our natural gas marketing segment.

During the year, we continued to successfully access the capital markets and received updated debt ratings from two rating agencies. In October 2009, we renewed a $200 million 364-day committed credit facility and in December 2009 we renewed a $450 million 364-day committed credit facility for our nonregulated operations. In March 2010, Moody's upgraded our rating outlook from stable to positive and affirmed the existing credit rating on our senior long-term debt and commercial paper while S&P affirmed our rating outlook as stable and our senior long-term debt credit rating. The new credit facilities should help ensure we have sufficient liquidity to fund our working capital needs, while our credit ratings should help us continue to obtain financing at a reasonable cost in the future.

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2010 and 2009:

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
	(In thousands, except per share data)			
Operating revenues	$1,940,266	$1,821,406	$3,233,118	$3,537,738
Gross profit	454,321	460,051	865,170	855,263
Operating expenses	229,781	233,504	450,034	465,522
Operating income	224,540	226,547	415,136	389,741
Miscellaneous income (expense)	49	(1,565)	(220)	(1,866)
Interest charges	39,582	35,533	78,290	74,524
Income before income taxes	185,007	189,449	336,626	313,351
Income tax expense	70,881	60,446	129,170	108,385
Net income	$ 114,126	$ 129,003	$ 207,456	$ 204,966
Diluted net income per share	$ 1.22	$ 1.40	$ 2.22	$ 2.23

Our consolidated net income (loss) during the three and six months ended March 31, 2010 and 2009 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2010	2009	Change
	(In thousands)		
Natural gas distribution segment	$102,731	$101,576	$ 1,155
Regulated transmission and storage segment	12,070	19,465	(7,395)
Natural gas marketing segment	(2,442)	3,348	(5,790)
Pipeline, storage and other segment	1,767	4,614	(2,847)
Net income	$114,126	$129,003	$(14,877)

	Six Months Ended March 31		
	2010	2009	Change
	(In thousands)		
Natural gas distribution segment	$154,179	$151,709	$ 2,470
Regulated transmission and storage segment	20,524	27,126	(6,602)
Natural gas marketing segment	26,570	13,923	12,647
Pipeline, storage and other segment	6,183	12,208	(6,025)
Net income	$207,456	$204,966	$ 2,490

The following tables segregate our consolidated net income (loss) and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended March 31		
	2010	2009	Change
	(In thousands, except per share data)		
Regulated operations	$114,801	$121,041	$ (6,240)
Nonregulated operations	(675)	7,962	(8,637)
Consolidated net income	$114,126	$129,003	$(14,877)
Diluted EPS from regulated operations	$ 1.23	$ 1.31	$ (0.08)
Diluted EPS from nonregulated operations	(0.01)	0.09	(0.10)
Consolidated diluted EPS	$ 1.22	$ 1.40	$ (0.18)

	Six Months Ended March 31		
	2010	2009	Change
	(In thousands, except per share data)		
Regulated operations	$174,703	$178,835	$(4,132)
Nonregulated operations	32,753	26,131	6,622
Consolidated net income	$207,456	$204,966	$ 2,490
Diluted EPS from regulated operations	$ 1.87	$ 1.95	$ (0.08)
Diluted EPS from nonregulated operations	0.35	0.28	0.07
Consolidated diluted EPS	$ 2.22	$ 2.23	$ (0.01)

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments,

known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

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

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Prior to January 1, 2009, timing differences existed between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. These timing differences had a significant temporary effect on operating income in periods with volatile gas prices, particularly in our Mid-Tex Division. Beginning January 1, 2009, changes in our franchise fee agreements in our Mid-Tex Division became effective, which have significantly reduced the impact of this timing difference. Although this timing difference will still be present for gross receipts taxes, the timing differences described above have been and should continue to be less significant.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Three Months Ended March 31, 2010 compared with Three Months Ended March 31, 2009

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2010 and 2009 are presented below.

	Three Months Ended March 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Gross profit	$385,385	$367,080	$18,305
Operating expenses	189,821	193,352	(3,531)
Operating income	195,564	173,728	21,836
Miscellaneous income	776	835	(59)
Interest charges	29,256	28,821	435
Income before income taxes	167,084	145,742	21,342
Income tax expense	64,353	44,166	20,187
Net income	$102,731	$101,576	$ 1,155
Consolidated natural gas distribution sales volumes — MMcf	158,530	121,560	36,970
Consolidated natural gas distribution transportation volumes — MMcf	39,294	35,061	4,233
Total consolidated natural gas distribution throughput — MMcf	197,824	156,621	41,203
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.48	$ (0.02)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 6.19	$ 7.10	$ (0.91)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the three months ended March 31, 2010 and 2009. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2010	2009	Change
	(In thousands)		
Mid-Tex	$ 79,843	$ 80,374	$ (531)
Kentucky/Mid-States	31,000	27,404	3,596
Louisiana	22,831	19,782	3,049
West Texas	21,400	14,806	6,594
Mississippi	17,852	16,771	1,081
Colorado-Kansas	14,267	13,623	644
Other	8,371	968	7,403
Total	$195,564	$173,728	$21,836

The $18.3 million increase in natural gas distribution gross profit primarily reflects rate adjustments and increased throughput as follows:

- $12.7 million net increase in rate adjustments, primarily in the West Texas, Mid-Tex, Louisiana and Mississippi service areas.

- $8.7 million increase as a result of a 26 percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

- $4.9 million increase in revenue-related taxes primarily due to higher revenues, on which the tax is calculated.

These increases were partially offset by:

- $7.0 million decrease related to a prior year reversal of an accrual for estimated unrecoverable gas costs that did not recur in the current year.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, decreased $3.5 million, primarily due to the following:

- $7.4 million decrease due to a state sales tax reimbursement received in March 2010.

- $1.4 million decrease due to lower contract labor expense.

These decreases were partially offset by a $4.8 million increase in employee-related expenses.

Additionally, results for the quarter ended March 31, 2009, were favorably impacted by a one-time tax benefit of $10.5 million. The benefit arose in the prior-year quarter after the Company updated tax rates used to record deferred taxes.

Six Months Ended March 31, 2010 compared with Six Months Ended March 31, 2009

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2010 and 2009 are presented below.

	Six Months Ended March 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Gross profit	$680,012	$665,464	$14,548
Operating expenses	371,701	379,231	(7,530)
Operating income	308,311	286,233	22,078
Miscellaneous income	1,433	3,956	(2,523)
Interest charges	58,934	61,708	(2,774)
Income before income taxes	250,810	228,481	22,329
Income tax expense	96,631	76,772	19,859
Net income	$154,179	$151,709	$ 2,470
Consolidated natural gas distribution sales volumes — MMcf	257,844	213,006	44,838
Consolidated natural gas distribution transportation volumes — MMcf	74,501	69,397	5,104
Total consolidated natural gas distribution throughput — MMcf	332,345	282,403	49,942
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.46	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.77	$ 7.61	$ (1.84)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the six months ended March 31, 2010 and 2009. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2010	2009	Change
	(In thousands)		
Mid-Tex	$130,224	$133,052	$ (2,828)
Kentucky/Mid-States	48,803	46,429	2,374
Louisiana	36,238	34,366	1,872
West Texas	33,157	22,819	10,338
Mississippi	27,654	25,206	2,448
Colorado-Kansas	22,873	22,224	649
Other	9,362	2,137	7,225
Total	$308,311	$286,233	$22,078

The $14.5 million increase in natural gas distribution gross profit primarily reflects rate adjustments and increased throughput as follows:

- $22.5 million net increase in rate adjustments, primarily in the West Texas, Mid-Tex, Louisiana and Mississippi service areas.
- $11.0 million increase as a result of an 18 percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

These increases were partially offset by:

- $8.3 million decrease due to a non-recurring adjustment recorded in the prior-year period to update the estimate for gas delivered to customers but not yet billed to reflect base rate changes.
- $7.0 million decrease related to a prior year reversal of an accrual for estimated unrecoverable gas costs that did not recur in the current year.
- $2.7 million decrease due to a decrease in revenue-related taxes, primarily due to a decrease in revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $7.5 million, primarily due to the following:

- $7.4 million decrease due to a state sales tax reimbursement received in March 2010.
- $2.3 million decrease in taxes other than income due to lower franchise fees and state gross receipts taxes.
- $2.2 million decrease in contract labor expenses.
- $1.8 million decrease due to the absence of an impairment charge for available-for-sale securities recorded in December 2008.
- $1.3 million decrease due to lower insurance premiums.

These decreases were partially offset by a $7.6 million increase in employee-related expenses.

Miscellaneous income decreased $2.5 million due to lower interest income. Interest charges decreased $2.8 million primarily due to lower short-term debt balances and interest rates.

Results for the six months ended March 31, 2009, were favorably impacted by the aforementioned one-time tax benefit of $10.5 million related to updated tax rates used to record deferred taxes.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the six months ended March 31, 2010 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $19.0 million resulting from ratemaking activity became effective in the six months ended March 31, 2010 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Rate case filings	$ 9,195
Annual rate filing mechanisms	7,172
Other rate activity	2,630
	$18,997

Additionally, the following ratemaking efforts were in progress during the second quarter of fiscal 2010 but had not been completed as of March 31, 2010.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Atmos Pipeline — Texas	GRIP[1]	RRC[2]	$ 13,540
Colorado/Kansas	Rate Case	Kansas	6,015
Kentucky/Mid-States	PRP[3]	Georgia	764
	Rate Case[4]	Kentucky	9,486
	Rate Case	Missouri	6,439
Louisiana	RSC[5]	Louisiana	1,841
	RSC	Louisiana	4,296
Mid-Tex	GRIP[1][6]	Dallas & RRC	2,985
	Rate Review Mechanism (RRM)	Settled Cities	56,827
West Texas	GRIP[1]	RRC	370
			$102,563

(1) Gas Reliability Infrastructure Program (GRIP) is a rate adjustment that allows utilities to recover additional invested capital without filing a full rate case.

(2) Rate actions for the Atmos Pipeline — Texas Division are under the jurisdiction of the Railroad Commission of Texas (RRC).

(3) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(4) The Company and Attorney General of the Commonwealth of Kentucky have filed a joint settlement with the Kentucky Commission requesting approval of a settlement in the amount of $5.9 million. Additionally, the settlement recommends moving bad debt recovery related to gas costs from base rates to Gas Cost Adjustment rates for recovery ($0.7 million) and approval of a pipeline replacement program.

(5) The Louisiana Commission Staff recommended an increase of $1.7 million effective April 1, 2010, which the Commission accepted.

(6) This GRIP filing is based on a Mid-Tex System-wide basis and made concurrently with the City of Dallas and the RRC for approval of their respective jurisdictional customers.

Additionally, in April 2010, our West Texas Division filed rate review mechanism filings with the City of Amarillo, City of Lubbock and West Texas Cities group for a combined increase of $6.6 million.

Rate Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2010 Rate Case Filings:			
Kentucky/Mid-States	Georgia	$2,935	3/31/2010
Mid-Tex	Texas[1]	2,963	01/26/2010
Colorado/Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$9,195	

(1) In its final order, the RRC approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Net of the GRIP 2008 rates that will be superseded, operating income will increase $0.2 million. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

GRIP Filings

GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. The Company had no GRIP filings approved as of March 31, 2010. However, on April 20, 2010, the RRC approved an Atmos Pipeline — Texas GRIP filing in the amount of $13.4 million.

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate

stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the six months ended March 31, 2010.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2010 Filings:				
Mississippi	Mississippi	6/30/2009	$3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$7,172	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2010:

Division	Jurisdiction	Rate Activity	Increase in Operating Income	Effective Date
			(In thousands)	
2010 Other Rate Activity:				
Kentucky/Mid-States	Missouri	ISRS[1]	$ 563	03/02/2010
Colorado-Kansas	Kansas	Ad Valorem[2]	392	01/05/2010
	Kansas	GSRS[3]	766	12/12/2009
Kentucky/Mid-States	Georgia	PRP Surcharge	909	10/01/2009
Total 2010 Other Rate Activity			$2,630	

(1) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

(2) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in the Company's base rates.

(3) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, 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.

Three Months Ended March 31, 2010 compared with Three Months Ended March 31, 2009

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2010 and 2009 are presented below.

	Three Months Ended March 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 33,214	$ 27,061	$ 6,153
Third-party transportation	16,335	23,846	(7,511)
Storage and park and lend services	2,673	2,657	16
Other	2,959	5,670	(2,711)
Gross profit	55,181	59,234	(4,053)
Operating expenses	28,479	24,905	3,574
Operating income	26,702	34,329	(7,627)
Miscellaneous income (expense)	(20)	283	(303)
Interest charges	7,954	7,349	605
Income before income taxes	18,728	27,263	(8,535)
Income tax expense	6,658	7,798	(1,140)
Net income	$ 12,070	$ 19,465	$ (7,395)
Gross pipeline transportation volumes — MMcf	192,441	193,356	(915)
Consolidated pipeline transportation volumes — MMcf	98,418	123,285	(24,867)

The $4.1 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $3.5 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.
- $2.8 million decrease due to the absence of excess inventory sales.
- $2.6 million decrease in market-based demand fees, priority reservation fees and compression activity associated with lower throughput.

These decreases were partially offset by the following:

- $3.2 million increase due to increased through system volumes primarily associated with colder weather in our Mid-Tex service area.
- $1.5 million increase associated with our GRIP filings.

Operating expenses increased $3.6 million primarily due to higher levels of pipeline maintenance activities and employee-related expenses.

Six Months Ended March 31, 2010 compared with Six Months Ended March 31, 2009

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2010 and 2009 are presented below.

	Six Months Ended March 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 59,925	$ 51,413	$ 8,512
Third-party transportation	31,577	49,212	(17,635)
Storage and park and lend services	5,278	5,014	264
Other	5,261	8,277	(3,016)
Gross profit	102,041	113,916	(11,875)
Operating expenses	54,267	60,217	(5,950)
Operating income	47,774	53,699	(5,925)
Miscellaneous income	23	1,098	(1,075)
Interest charges	15,922	15,428	494
Income before income taxes	31,875	39,369	(7,494)
Income tax expense	11,351	12,243	(892)
Net income	$ 20,524	$ 27,126	$ (6,602)
Gross pipeline transportation volumes — MMcf	350,214	385,528	(35,314)
Consolidated pipeline transportation volumes — MMcf	194,356	259,143	(64,787)

The $11.9 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $7.5 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.
- $3.9 million decrease in market-based demand fees, priority reservation fees and compression activity associated with lower throughput.
- $2.8 million decrease due to the absence of excess inventory sales.

These decreases were partially offset by a $3.1 million increase associated with our GRIP filings.

Operating expenses decreased $6.0 million primarily due to lower levels of pipeline maintenance activities.

Natural Gas Marketing Segment

Atmos Energy Marketing LLC's (AEM) primary business is to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. In addition, AEM utilizes proprietary and customer-owned transportation and storage assets to provide 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 financial instruments (delivered gas business). As a result, AEM's margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEM also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity we own or control in our natural gas distribution and natural gas marketing segments. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEM has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEM continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEM may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEM elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to hedge the original financial instruments. If AEM elects to defer the withdrawal of gas, it will reset its financial instruments by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEM also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory is hedged and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Due to the nature of these operations, natural gas prices have a significant impact on our natural gas marketing operations. Within our delivered gas business, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our natural gas marketing segment. Increased price volatility often has a significant impact on the spreads between market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Three Months Ended March 31, 2010 compared with Three Months Ended March 31, 2009

Financial and operational highlights for our natural gas marketing segment for the three months ended March 31, 2010 and 2009 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended March 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 17,126	$ 23,165	$ (6,039)
Asset optimization[1]	24,891	(2,073)	26,964
	42,017	21,092	20,925
Unrealized margins	(35,537)	2,452	(37,989)
Gross profit	6,480	23,544	(17,064)
Operating expenses	7,702	13,165	(5,463)
Operating income (loss)	(1,222)	10,379	(11,601)
Miscellaneous income	287	118	169
Interest charges	2,820	3,461	(641)
Income (loss) before income taxes	(3,755)	7,036	(10,791)
Income tax expense (benefit)	(1,313)	3,688	(5,001)
Net income (loss)	$ (2,442)	$ 3,348	$ (5,790)
Gross natural gas marketing sales volumes — MMcf	123,877	123,066	811
Consolidated natural gas marketing sales volumes — MMcf	104,893	104,973	(80)
Net physical position (Bcf)	22.7	21.9	0.8

[1] Net of storage fees of $3.5 million and $2.9 million.

AEM's asset optimization activities contributed 59 percent to total realized margins during the second quarter of fiscal 2010, with the delivered gas business contributing the remaining 41 percent. The $20.9 million increase in realized gross profit reflected:

- A $26.9 million increase in asset optimization margins primarily attributable to the timing of the settlement of open positions. During the three months ended March 31, 2010, AEM recognized the gains it had captured from its optimization activities during the first quarter of fiscal 2010. In the prior year, AEM recognized similar gains from its optimization activities during the first quarter of fiscal 2009.
- A $6.0 million decrease in realized delivered gas margins due to lower per-unit margins as a result of narrowing basis spreads.

The increase in realized gross profit was more than offset by a $38.0 million decrease in unrealized margins primarily due to the realization during the current quarter of unrealized gains that had been recorded in the first quarter of fiscal 2010.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income taxes, decreased $5.5 million primarily due to a decrease in employee and other administrative costs.

Six Months Ended March 31, 2010 compared with Six Months Ended March 31, 2009

Financial and operational highlights for our natural gas marketing segment for the six months ended March 31, 2010 and 2009 are presented below.

	Six Months Ended March 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 33,213	$ 41,718	$ (8,505)
Asset optimization[(1)]	31,320	34,866	(3,546)
	64,533	76,584	(12,051)
Unrealized margins	1,732	(23,017)	24,749
Gross profit	66,265	53,567	12,698
Operating expenses	17,803	22,675	(4,872)
Operating income	48,462	30,892	17,570
Miscellaneous income	495	419	76
Interest charges	5,198	7,363	(2,165)
Income before income taxes	43,759	23,948	19,811
Income tax expense	17,189	10,025	7,164
Net income	$ 26,570	$ 13,923	$ 12,647
Gross natural gas marketing sales volumes — MMcf	226,138	233,724	(7,586)
Consolidated natural gas marketing sales volumes — MMcf	192,122	198,281	(6,159)
Net physical position (Bcf)	22.7	21.9	0.8

(1) Net of storage fees of $6.0 million and $5.5 million.

AEM's delivered gas business contributed 51 percent to total realized margins during the six months ended March 31, 2010 with asset optimization activities contributing the remaining 49 percent. The $12.0 million decrease in realized gross profit reflected the following:

- $8.5 million decrease in realized delivered gas margins due to lower per-unit margins as a result of narrowing basis spreads, combined with lower delivered sales volumes. Per-unit margins were $0.15/Mcf in the current-year period compared with $0.18/Mcf in the prior-year period, while delivered sales volumes were three percent lower in the current-year period when compared with the prior-year period.
- $3.5 million decrease in asset optimization margins primarily attributable to lower natural gas volatility in the current-year period which created fewer opportunities to optimize our storage assets.

The decrease in realized gross profit was more than offset by a $24.7 million increase in unrealized margins due to the period-over-period timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes and asset impairments decreased $4.9 million primarily due to a decrease in employee and other administrative costs.

Asset Optimization Activities

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before associated storage fees, that it captured through the purchase and sale of physical natural gas and the execution of the

associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement, is referred to as the potential gross profit.

We define potential gross profit as the change in AEM's gross profit from asset optimization activities in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injections/withdrawals and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEM's economic value and its potential gross profit (loss) at March 31, 2010 and 2009.

	March 31	
	2010	2009
	(In millions, unless otherwise noted)	
Economic value	$ 0.6	$ 33.4
Associated unrealized (gains) losses	7.5	(2.4)
Subtotal	8.1	31.0
Related fees[(1)]	(13.8)	(16.0)
Potential gross profit (loss)	$ (5.7)	$ 15.0
Net physical position (Bcf)	22.7	21.9

(1) Related fees represent AEM's contractual costs to acquire the storage capacity utilized in its asset optimization operations. The fees primarily consist of demand fees and contractual obligations to sell gas below market index prices in exchange for the right to manage and optimize third party storage assets for the positions AEM has entered into as of March 31, 2010 and 2009.

During the six months ended March 31, 2010, AEM's economic value decreased from $28.6 million, or $2.07/Mcf at September 30, 2009 to $0.6 million, or $0.02/Mcf. This compares unfavorably to AEM's economic value at March 31, 2009 of $33.4 million, or $1.53/Mcf.

Early in the first quarter of fiscal 2010, AEM withdrew gas and realized previously captured spread values. As current cash prices declined during the first fiscal quarter, AEM injected gas and rolled positions into the second fiscal quarter to increase economic value. These positions were settled in the second fiscal quarter and the associated economic value was realized. However, cash prices continued to fall and weak market fundamentals created limited opportunities to capture economic value. Therefore, AEM injected additional gas into storage. However, as of March 31, 2010, AEM had established just a limited number of positions as it believes future market conditions will create improved opportunities to capture spread values.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit calculated as of March 31, 2010 will be fully realized in the future nor can we predict in what time periods such realization

may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS is engaged in nonregulated transmission, storage and natural gas-gathering services. Its primary asset is a proprietary 21 mile pipeline located in New Orleans, Louisiana that is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana, our natural gas marketing segment, and, on a more limited basis, for third parties. APS also owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for additional pipeline capacity to meet customer demand during peak periods.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements. APS also seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls by engaging in natural gas storage transactions in which it seeks to find and profit from the pricing differences that occur over time.

Results for this segment are primarily impacted by seasonal weather patterns and, similar to our natural gas marketing segment, volatility in the natural gas markets. Additionally, this segment's results include an unrealized component as APS hedges its risk associated with its asset optimization activities.

Three Months Ended March 31, 2010 compared with Three Months Ended March 31, 2009

Financial and operational highlights for our pipeline, storage and other segment for the three months ended March 31, 2010 and 2009 are presented below.

	Three Months Ended March 31		
	2010	2009	Change
	(In thousands)		
Asset optimization	$ 7,392	$15,157	$(7,765)
Storage and transportation services	3,093	3,312	(219)
Other	1,200	350	850
Unrealized margins	(4,004)	(8,203)	4,199
Gross profit	7,681	10,616	(2,935)
Operating expenses	4,185	2,591	1,594
Operating income	3,496	8,025	(4,529)
Miscellaneous income	980	2,060	(1,080)
Interest charges	1,526	677	849
Income before income taxes	2,950	9,408	(6,458)
Income tax expense	1,183	4,794	(3,611)
Net income	$ 1,767	$ 4,614	$(2,847)

Gross profit from our pipeline, storage and other segment decreased $2.9 million primarily due to the following:

- $6.5 million decrease in margins earned from utilizing assets subject to APS' asset management plans due to fewer trading opportunities this year compared to the prior-year period which created a less volatile natural gas market.
- $1.8 million decrease in basis gains earned from utilizing leased capacity.
- $4.2 million increase in unrealized margins associated with our asset optimization activities.

Operating expenses increased $1.6 million primarily due to legal and other administrative costs.

Six Months Ended March 31, 2010 compared with Six Months Ended March 31, 2009

Financial and operational highlights for our pipeline, storage and other segment for the six months ended March 31, 2010 and 2009 are presented below.

	Six Months Ended March 31		
	2010	2009	Change
		(In thousands)	
Asset optimization	$ 7,489	$20,624	$(13,135)
Storage and transportation services	6,427	6,627	(200)
Other	1,144	1,339	(195)
Unrealized margins	2,611	(5,429)	8,040
Gross profit	17,671	23,161	(5,490)
Operating expenses	7,082	4,416	2,666
Operating income	10,589	18,745	(8,156)
Miscellaneous income	1,433	4,221	(2,788)
Interest charges	1,840	1,413	427
Income before income taxes	10,182	21,553	(11,371)
Income tax expense	3,999	9,345	(5,346)
Net income	$ 6,183	$12,208	$ (6,025)

Gross profit from our pipeline, storage and other segment decreased $5.5 million primarily due to the following:

- $6.4 million decrease from lower margins earned on storage optimization activities.
- $3.7 million decrease in basis gains earned from utilizing leased capacity.
- $3.0 million decrease from lower margins earned on asset management plans.
- $8.0 million increase in unrealized margins associated with our asset optimization activities.

Operating expenses increased $2.7 million primarily due to the following:

- $1.4 million increase in other administrative costs.
- $0.7 million increase in employee costs.
- $0.3 million increase in property taxes.

Miscellaneous income decreased $2.8 million due to lower interest expense incurred by this segment.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources, including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2010.

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, investing and financing activities for the six months ended March 31, 2010 and 2009 are presented below.

	Six Months Ended March 31		
	2010	2009	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 483,458	$ 614,622	$(131,164)
Investing activities	(233,575)	(225,255)	(8,320)
Financing activities	(129,933)	46,001	(175,934)
Change in cash and cash equivalents	119,950	435,368	(315,418)
Cash and cash equivalents at beginning of period	111,203	46,717	64,486
Cash and cash equivalents at end of period	$ 231,153	$ 482,085	$(250,932)

Cash flows from operating activities

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

For the six months ended March 31, 2010, we generated operating cash flow of $483.5 million from operating activities compared with $614.6 million for the six months ended March 31, 2009, primarily due to the fluctuation in gas costs. Gas costs, which reached historically high levels during the 2008 injection season, declined sharply when the economy slipped into the recession and have remained relatively stable since that time. Operating cash flow for the fiscal 2010 period reflects the recovery of lower gas costs through purchased gas recovery mechanisms and sales. This is in contrast to the fiscal 2009 period, where operating cash flow was favorably influenced by the recovery of high gas costs during a period of falling prices.

Cash flows from investing activities

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

Capital expenditures for fiscal 2010 are expected to range from $520 million to $535 million. For the six months ended March 31, 2010, capital expenditures were $232.6 million compared with $221.3 million for the six months ended March 31, 2009. The $11.3 million increase in capital expenditures primarily reflects spending for the relocation of our information technology data center to a new facility.

Cash flows from financing activities

For the six months ended March 31, 2010, our financing activities used $129.9 million of cash compared with a cash inflow of $46.0 million in the prior-year period, primarily due to the following:

- $446.2 million decrease in cash inflows due to the absence of proceeds from the issuance of long-term debt that occurred in the prior-year period.
- $3.8 million decrease due to a substantial decrease in the number of shares of common stock issued to provide shares for our Retirement Savings Plan due to a change to purchasing such shares on the open market.
- $2.1 million additional cash used due to an increase in dividends paid in the current year compared to the prior year.
- $1.9 million decrease in cash inflows due to the absence of the settlement of a Treasury lock agreement that occurred in the prior-year period.

These decreases in financing cash flows were partially offset by a $277.6 million increase due to lower short-term debt repayments. In the current-year period, $75.9 million of short-term debt was repaid, compared with $353.5 million in the prior-year period. The reduction in net borrowings reflects the timing of the use of our line of credit to finance natural gas purchases and working capital.

The following table summarizes our share issuances for the six months ended March 31, 2010 and 2009.

	Six Months Ended March 31	
	2010	**2009**
Shares issued:		
Direct Stock Purchase Plan	103,529	220,361
Retirement Savings Plan and Trust	79,722	330,990
1998 Long-Term Incentive Plan	409,535	579,990
Outside Directors Stock-for-Fee Plan	2,040	1,590
Total shares issued	594,826	1,132,931

The year-over-year decrease in the number of shares issued primarily reflects the fact that we have started using shares purchased in the open market rather than issuing shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. In addition, we awarded fewer shares under our 1998 Long-Term Incentive Plan due to the Company achieving a lower level of performance relative to the target performance established under the Plan during fiscal 2009 compared to fiscal 2008. Further, a higher average stock price during the second quarter of fiscal 2010 compared to the second quarter of 2009 caused us to issue fewer shares during the quarter.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. As of March 31, 2010, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $1.1 billion. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

On March 31, 2010, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $1.3 billion in common stock and/or debt securities available for issuance.

We had already received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under the new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities.

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 regulated and nonregulated 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). In March 2010, Moody's upgraded our rating outlook from stable to positive and affirmed the credit rating on our senior long-term debt at Baa2 and on our commercial paper at P-2. Moody's stated that the key driver for the upgrade was successful rate case outcomes over the past year. In March 2010, S&P affirmed our senior long-term debt credit rating of BBB+ and our rating outlook as stable. Fitch still maintains a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently 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 March 31, 2010. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2010, September 30, 2009 and March 31, 2009:

	March 31, 2010		September 30, 2009		March 31, 2009	
	(In thousands, except percentages)					
Short-term debt	$ —	—	$ 72,550	1.6%	$ —	—
Long-term debt	2,169,606	48.1%	2,169,531	49.1%	2,569,366	54.1%
Shareholders' equity	2,338,843	51.9%	2,176,761	49.3%	2,178,494	45.9%
Total	$4,508,449	100.0%	$4,418,842	100.0%	$4,747,860	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 48.1 percent at March 31, 2010, 50.7 percent at September 30, 2009 and 54.1 percent at March 31, 2009. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2010.

As we previously discussed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provides the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. If the option is exercised, we will retain a non-controlling equity position in Fort Necessity and will share in a percentage of the profits.

Risk Management Activities

We conduct risk management activities through our natural gas distribution, natural gas marketing and pipeline, storage and other segments. In our natural gas distribution segment, we use a combination of physical 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 and pipeline, storage and other segments, 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and six months ended March 31, 2010 and 2009:

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
	(In thousands)			
Fair value of contracts at beginning of period	$(17,470)	$(51,314)	$(14,166)	$ (63,677)
Contracts realized/settled	(13,390)	(47,231)	(34,418)	(100,996)
Fair value of new contracts	(1,288)	277	(2,236)	(4,006)
Other changes in value	10,413	76,405	29,085	146,816
Fair value of contracts at end of period	$(21,735)	$(21,863)	$(21,735)	$ (21,863)

The fair value of our natural gas distribution segment's financial instruments at March 31, 2010 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2010				
	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	$(21,735)	$—	$—	$—	$(21,735)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(21,735)	$—	$—	$—	$(21,735)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the three and six months ended March 31, 2010 and 2009:

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
	(In thousands)			
Fair value of contracts at beginning of period	$ 32,306	$(28,598)	$ 26,698	$ 16,542
Contracts realized/settled	(22,030)	6,972	(24,242)	(13,275)
Fair value of new contracts	—	—	—	—
Other changes in value	3,951	(11,020)	11,771	(35,913)
Fair value of contracts at end of period	14,227	(32,646)	14,227	(32,646)
Netting of cash collateral	7,199	79,098	7,199	79,098
Cash collateral and fair value of contracts at period end	$ 21,426	$ 46,452	$ 21,426	$ 46,452

The fair value of our natural gas marketing segment's financial instruments at March 31, 2010 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2010				
	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	$9,168	$5,746	$(687)	$—	$14,227
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$9,168	$5,746	$(687)	$—	$14,227

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2010 and 2009, our total net periodic pension and other benefits cost was $25.4 million and $24.1 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2010 costs were determined using a September 30, 2009 measurement date. As of September 30, 2009, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of September 30, 2008, the measurement date for our fiscal 2009 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2010 pension and benefit costs to 5.52 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is mitigated by the fact that fluctuations in asset values are "smoothed" for purposes of determining net periodic pension cost. Accordingly, asset gains and losses are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Accordingly, our fiscal 2010 pension and postretirement medical costs were materially the same as in fiscal 2009.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2010. Based upon this valuation, we expect we will be required to contribute less than $5 million to our pension plans by September 15, 2010. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $12 million to these plans during fiscal 2010.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage, natural gas marketing and pipeline, storage and other segments for the three and six month periods ended March 31, 2010 and 2009.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
METERS IN SERVICE, end of period				
Residential	2,937,163	2,937,865	2,937,163	2,937,865
Commercial	272,925	274,449	272,925	274,449
Industrial	2,496	2,212	2,496	2,212
Public authority and other	9,461	9,243	9,461	9,243
Total meters	3,222,045	3,223,769	3,222,045	3,223,769
INVENTORY STORAGE BALANCE — Bcf	24.4	31.9	24.4	31.9
SALES VOLUMES — MMcf[(1)]				
Gas sales volumes				
Residential	100,858	74,467	161,404	128,675
Commercial	46,615	36,689	77,105	65,018
Industrial	6,660	5,758	11,979	11,158
Public authority and other	4,397	4,646	7,356	8,155
Total gas sales volumes	158,530	121,560	257,844	213,006
Transportation volumes	40,545	36,169	76,786	71,454
Total throughput	199,075	157,729	334,630	284,460
OPERATING REVENUES (000's)[(1)]				
Gas sales revenues				
Residential	$ 897,249	$ 785,456	$1,405,160	$1,432,556
Commercial	366,260	334,815	585,680	637,509
Industrial	41,777	46,259	72,810	96,414
Public authority and other	32,386	36,991	52,584	68,385
Total gas sales revenues	1,337,672	1,203,521	2,116,234	2,234,864
Transportation revenues	18,219	16,889	34,694	32,655
Other gas revenues	10,097	10,010	17,954	18,869
Total operating revenues	$1,365,988	$1,230,420	$2,168,882	$2,286,388
Average transportation revenue per Mcf	$ 0.45	$ 0.47	$ 0.45	$ 0.46
Average cost of gas per Mcf sold	$ 6.19	$ 7.10	$ 5.77	$ 7.61

See footnote following these tables.

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

	Three Months Ended March 31		Six Months Ended March 31	
	2010	2009	2010	2009
CUSTOMERS, end of period				
Industrial	727	698	727	698
Municipal	62	61	62	61
Other	498	527	498	527
Total	1,287	1,286	1,287	1,286
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	20.1	20.4	20.1	20.4
Pipeline, storage and other	1.2	2.0	1.2	2.0
Total	21.3	22.4	21.3	22.4
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	192,441	193,356	350,214	385,528
NATURAL GAS MARKETING SALES VOLUMES — MMcf[(1)]	123,877	123,066	226,138	233,724
OPERATING REVENUES (000's)[(1)]				
Regulated transmission and storage	$ 55,181	$ 59,234	$ 102,041	$ 113,916
Natural gas marketing	692,152	708,658	1,236,423	1,496,153
Pipeline, storage and other	9,050	12,272	20,673	28,720
Total operating revenues	$756,383	$780,164	$1,359,137	$1,638,789

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the six months ended March 31, 2010, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of March 31, 2010 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the six months ended March 31, 2010, except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 5. *Other Information*

At the Annual Meeting of Shareholders of Atmos Energy Corporation on February 3, 2010, 81,757,639 votes were cast as follows:

	Votes For	Votes Withheld/ Against	Votes Abstaining	Broker Non-Votes
Class I Director:				
Kim R. Cocklin	64,574,447	1,217,145	—	15,966,047
Class III Directors:				
Robert W. Best	63,891,229	1,900,363	—	15,966,047
Robert C. Grable	64,932,497	859,095	—	15,966,047
Phillip E. Nichol	64,102,746	1,688,846	—	15,966,047
Charles K. Vaughan	64,210,783	1,580,809	—	15,966,047
Proposal regarding declassification of the Board of Directors	79,072,204	1,757,120	928,315	—
Ratification of the Audit Committee's engagement of Ernst & Young LLP to serve as the Company's registered independent public accounting firm for fiscal year 2010	80,853,517	734,364	169,758	—

Mr. Travis W. Bain II, a Class I director and Mr. Thomas J. Garland, a Class III director, retired on February 3, 2010 at the conclusion of the Annual Meeting of Shareholders, in accordance with the Board's mandatory retirement policy. The remaining directors will continue to serve until the expiration of their terms. The term of the Class I directors, Kim R. Cocklin, Richard W. Douglas, Ruben E. Esquivel and Richard K. Gordon, will expire in 2011. The term of the Class II directors, Richard W. Cardin, Thomas C. Meredith, Nancy K. Quinn, Stephen R. Springer and Richard Ware II, will expire in 2012. The term of the Class III directors, Robert W. Best, Robert C. Grable, Phillip E. Nichol and Charles K. Vaughan will expire in 2013. As a result of the declassification of the Board, which was approved by our shareholders, beginning with the 2011 Annual Meeting of Shareholders, each director elected will serve a one-year term.

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.

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President, Chief Financial Officer and Treasurer
(Duly authorized signatory)

Date: May 6, 2010

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
3.1	Restated Articles of Incorporation of Atmos Energy Corporation — Texas (As Amended Effective February 3, 2010)	
3.2	Restated Articles of Incorporation of Atmos Energy Corporation — Virginia (As Amended Effective February 3, 2010)	
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.

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, 2010

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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 29, 2010.

Class	Shares Outstanding
No Par Value	90,154,801

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2010	September 30, 2009
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,402,065	$6,086,618
Less accumulated depreciation and amortization	1,733,022	1,647,515
Net property, plant and equipment	4,669,043	4,439,103
Current assets		
Cash and cash equivalents	180,383	111,203
Accounts receivable, net	299,835	232,806
Gas stored underground	263,752	352,728
Other current assets	130,003	132,203
Total current assets	873,973	828,940
Goodwill and intangible assets	739,593	740,064
Deferred charges and other assets	303,041	335,659
	$6,585,650	$6,343,766
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, 2010 — 93,112,688 shares; September 30, 2009 — 92,551,709 shares	$ 466	$ 463
Additional paid-in capital	1,812,088	1,791,129
Retained earnings	515,742	405,353
Accumulated other comprehensive loss	(14,566)	(20,184)
Shareholders' equity	2,313,730	2,176,761
Long-term debt	1,809,546	2,169,400
Total capitalization	4,123,276	4,346,161
Current liabilities		
Accounts payable and accrued liabilities	254,150	207,421
Other current liabilities	393,478	457,319
Short-term debt	—	72,550
Current maturities of long-term debt	360,131	131
Total current liabilities	1,007,759	737,421
Deferred income taxes	755,722	570,940
Regulatory cost of removal obligation	314,708	321,086
Deferred credits and other liabilities	384,185	368,158
	$6,585,650	$6,343,766

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2010	2009
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 405,271	$ 386,985
Regulated transmission and storage segment	44,957	49,345
Natural gas marketing segment	421,406	453,504
Pipeline, storage and other segment	8,196	8,226
Intersegment eliminations	(109,573)	(117,285)
	770,257	780,775
Purchased gas cost		
Natural gas distribution segment	208,378	195,303
Regulated transmission and storage segment	—	—
Natural gas marketing segment	415,101	438,482
Pipeline, storage and other segment	2,730	4,212
Intersegment eliminations	(109,180)	(116,862)
	517,029	521,135
Gross profit	253,228	259,640
Operating expenses		
Operation and maintenance	113,348	110,895
Depreciation and amortization	53,288	54,181
Taxes, other than income	52,483	47,577
Asset impairments	—	3,304
Total operating expenses	219,119	215,957
Operating income	34,109	43,683
Miscellaneous income (expense)	(850)	1,219
Interest charges	37,290	41,511
Income (loss) before income taxes	(4,031)	3,391
Income tax expense (benefit)	(877)	1,427
Net income (loss)	$ (3,154)	$ 1,964
Basic net income (loss) per share	$ (0.03)	$ 0.02
Diluted net income (loss) per share	$ (0.03)	$ 0.02
Cash dividends per share	$ 0.335	$ 0.330
Weighted average shares outstanding:		
Basic	92,648	91,338
Diluted	92,648	91,652

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2010	2009
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,574,153	$2,673,373
Regulated transmission and storage segment	146,998	163,261
Natural gas marketing segment	1,657,829	1,949,657
Pipeline, storage and other segment	28,869	36,946
Intersegment eliminations	(404,474)	(504,724)
	4,003,375	4,318,513
Purchased gas cost		
Natural gas distribution segment	1,697,248	1,816,227
Regulated transmission and storage segment	—	—
Natural gas marketing segment	1,585,259	1,881,068
Pipeline, storage and other segment	5,732	9,771
Intersegment eliminations	(403,262)	(503,456)
	2,884,977	3,203,610
Gross profit	1,118,398	1,114,903
Operating expenses		
Operation and maintenance	354,298	365,312
Depreciation and amortization	160,207	160,757
Taxes, other than income	154,648	150,028
Asset impairments	—	5,382
Total operating expenses	669,153	681,479
Operating income	449,245	433,424
Miscellaneous expense	(1,070)	(647)
Interest charges	115,580	116,035
Income before income taxes	332,595	316,742
Income tax expense	128,293	109,812
Net income	$ 204,302	$ 206,930
Basic net income per share	$ 2.19	$ 2.25
Diluted net income per share	$ 2.18	$ 2.25
Cash dividends per share	$ 1.005	$ 0.990
Weighted average shares outstanding:		
Basic	92,513	90,940
Diluted	92,856	91,246

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2010	2009
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 204,302	$ 206,930
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	160,207	160,757
Charged to other accounts	116	60
Deferred income taxes	186,325	62,658
Other	18,425	23,009
Net assets / liabilities from risk management activities	3,429	53,711
Net change in operating assets and liabilities	21,760	317,469
Net cash provided by operating activities	594,564	824,594
Cash Flows From Investing Activities		
Capital expenditures	(362,349)	(342,326)
Other, net	(438)	(6,094)
Net cash used in investing activities	(362,787)	(348,420)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(76,019)	(366,449)
Net proceeds from issuance of long-term debt	—	445,623
Settlement of Treasury lock agreement	—	1,938
Repayment of long-term debt	(66)	(407,287)
Cash dividends paid	(93,913)	(90,909)
Repurchase of equity awards	(1,173)	—
Issuance of common stock	8,574	19,928
Net cash used in financing activities	(162,597)	(397,156)
Net increase in cash and cash equivalents	69,180	79,018
Cash and cash equivalents at beginning of period	111,203	46,717
Cash and cash equivalents at end of period	$ 180,383	$ 125,735

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2010

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our natural gas distribution and regulated pipeline and storage businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast and include our natural gas marketing operations and pipeline, storage and other operations. These businesses are operated through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH), which is wholly owned by the Company and based in Houston, Texas. Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers and natural gas transportation and storage services to certain of our natural gas distribution divisions and third parties.

We operate the Company through the following four segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes our regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment*, which is comprised of our nonregulated natural gas gathering, transmission and storage services.

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2010 are not indicative of our results of operations for the full 2010 fiscal year, which ends September 30, 2010.

We have evaluated subsequent events from the June 30, 2010 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). On July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman, Sachs & Co. to repurchase $100 million of our outstanding common stock. The agreement is designed to offset stock grants made under various employee and director incentive compensation plans. The specific number of shares that we will ultimately repurchase in the transaction will be based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. The agreement is scheduled to end in March 2011, although the termination date may be accelerated. As a result of this transaction, our weighted-average shares outstanding will be reduced over the remaining three months of fiscal 2010.

Except for the accelerated share repurchase agreement, no events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009.

During the second quarter of fiscal 2010, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

During the nine months ended June 30, 2010, six new accounting standards became applicable to the Company. Except as indicated below, the adoption of these standards did not have a material impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the nine months ended June 30, 2010.

The determination of participating securities in the basic earnings per share calculation — The Financial Accounting Standards Board (FASB) issued guidance related to determining whether instruments granted in share-based payment transactions are considered participating securities. The FASB determined that non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents are participating securities and, as a result, companies with these types of participating securities must use the two-class method to compute earnings per share. Based on this guidance, the Company is required to calculate earnings per share using the two-class method and will include non-vested restricted stock and restricted stock units for which vesting is only predicated upon the passage of time in the basic earnings per share calculation. Non-vested restricted stock and restricted stock units for which vesting is predicated, in part upon the achievement of specified performance targets, continue to be excluded from the calculation of earnings per share. Although the provisions of this standard were effective for us as of October 1, 2009, prior-period earnings per share data must be recalculated and adjusted accordingly. The calculation of basic and diluted earnings per share pursuant

to the two-class method is presented in Note 6. The application of the two-class method resulted in the following changes to basic and diluted earnings per share for the three and nine months ended June 30, 2009.

	Three Months Ended June 30, 2009	Nine Months Ended June 30, 2009
	(In thousands, except per share amounts)	
Basic Earnings Per Share		
Basic EPS — as previously reported	$ 0.02	$ 2.28
Basic EPS — as adjusted	$ 0.02	$ 2.25
Weighted average shares outstanding — as previously reported	91,338	90,940
Weighted average shares outstanding — as adjusted	91,338	90,940
Diluted Earnings Per Share		
Diluted EPS — as previously reported	$ 0.02	$ 2.26
Diluted EPS — as adjusted	$ 0.02	$ 2.25
Weighted average shares outstanding — as previously reported	92,002	91,590
Weighted average shares outstanding — as adjusted	91,652	91,246

Fair value measurements of plan assets of a defined benefit pension or other postretirement plan — This guidance requires employers to disclose annually information about fair value measurements of the assets of a defined benefit pension or other postretirement plan in a manner similar to the requirements established for financial and non-financial assets. The objectives of the required disclosures are to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure fair value of plan assets and significant concentrations of risk within plan assets. These disclosures will appear in our Form 10-K for the year ending September 30, 2010.

Measurement of liabilities at fair value — This guidance requires that, effective October 1, 2009, when a quoted price in an active market for an identical liability is not available, we will be required to measure fair value using a valuation technique that uses quoted prices of similar liabilities, quoted prices of identical or similar liabilities when traded as assets, or another valuation technique that is consistent with U.S. generally accepted accounting principles (GAAP), such as the income or market approach. Additionally, when estimating the fair value of a liability, we will not be required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents our transfer of the liability. The adoption of this guidance did not impact our financial position, results of operations or cash flows.

Business combination accounting — Effective October 1, 2009, this new pronouncement established new principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. This update significantly changes the accounting for business combinations in a number of areas, including the treatment of contingent consideration, preacquisition contingencies, transaction costs and restructuring costs. In addition, under the new guidelines, changes in an acquired entity's deferred tax assets and uncertain tax positions after the measurement period will impact current period income tax expense.

Accounting and reporting for minority interests — In December 2007, the FASB issued guidance related to the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This new consolidation method significantly changed the accounting for transactions with minority interest holders beginning October 1, 2009. As of June 30, 2010, Atmos Energy did not have any transactions with minority interest holders.

Fair value disclosures — The FASB issued guidance that requires new disclosures surrounding fair value measurements to enhance the existing disclosure requirements including 1) information about transfers in and out of Level 1 and Level 2 fair value measurements as well as a detailed reconciliation of activity in Level 3 fair value measurements; 2) a more detailed level of disaggregation for each class of assets and liabilities; and 3) a requirement to disclose information about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements that fall in either Level 2 or Level 3. The new disclosures and clarifications of existing disclosures became effective for us on January 1, 2010, except for the disclosures related to the detailed reconciliation of Level 3 fair value measurements, which will become effective for us on October 1, 2011. As a result of adopting this standard, beginning in our second fiscal quarter we added a disclosure about the valuation techniques and inputs we used to measure fair value for our Level 2 recurring and nonrecurring fair value measurements which is included in Note 4. As of June 30, 2010, we did not have any Level 3 fair value measurements.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of June 30, 2010 and September 30, 2009 included the following:

	June 30, 2010	September 30, 2009
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$189,566	$197,743
Merger and integration costs, net	6,826	7,161
Deferred gas costs	678	22,233
Environmental costs	851	866
Rate case costs	3,991	5,923
Deferred franchise fees	466	10,014
Deferred income taxes, net	639	639
Other	762	6,218
	$203,779	$250,797
Regulatory liabilities:		
Deferred gas costs	$ 56,463	$110,754
Regulatory cost of removal obligation	343,765	335,428
Other	6,257	7,960
	$406,485	$454,142

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

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month and nine-month periods ended June 30, 2010 and 2009:

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
	(In thousands)			
Net income (loss)	$(3,154)	$ 1,964	$204,302	$206,930
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(996) and $1,282 for the three months ended June 30, 2010 and 2009 and of $(198) and $(2,477) for the nine months ended June 30, 2010 and 2009	(1,696)	2,086	(337)	(4,209)
Other than temporary impairment of investments, net of tax expense of $1,222 and $2,012 for the three and nine months ended June 30, 2009	—	2,082	—	3,370
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $247 and $320 for the three months ended June 30, 2010 and 2009 and $743 and $2,155 for the nine months ended June 30, 2010 and 2009	422	543	1,265	3,184
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $5,066 and $16,582 for the three months ended June 30, 2010 and 2009 and $2,999 and $(4,759) for the nine months ended June 30, 2010 and 2009	7,921	25,936	4,690	(6,379)
Comprehensive income	$ 3,493	$32,611	$209,920	$202,896

Accumulated other comprehensive loss, net of tax, as of June 30, 2010 and September 30, 2009 consisted of the following unrealized gains (losses):

	June 30, 2010	September 30, 2009
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 2,123	$ 2,460
Treasury lock agreements	(6,233)	(7,498)
Cash flow hedges	(10,456)	(15,146)
	$(14,566)	$(20,184)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. However, our pipeline, storage and other segment uses financial instruments acquired from Atmos Energy Marketing, LLC (AEM) on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2009-2010 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 29 percent, or 26.9 Bcf of the planned winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

Our natural gas marketing segment, through AEM, 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.

We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. Through asset optimization activities, we seek to maximize the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to

lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our natural gas marketing segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 49 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our natural gas marketing and pipeline, storage and other segments.

Also, in our natural gas marketing segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on June 30, 2010, AEH had net open positions (including existing storage) of 0.3 Bcf.

Interest Rate Risk Management Activities

Currently, we are not managing interest rate risk with financial instruments. However, in prior years, we periodically managed interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a cumulative net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts associated with these Treasury locks will be recognized by the end of fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of June 30, 2010, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2010, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other
			Quantity (MMcf)	
Commodity contracts	Fair Value	—	(19,288)	(1,710)
	Cash Flow	—	26,768	(2,580)
	Not designated	24,772	37,278	2,620
		24,772	44,758	(1,670)

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of June 30, 2010 and September 30, 2009. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $18.0 million and $11.7 million of cash held on deposit in margin accounts as of June 30, 2010 and September 30, 2009 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
			(In thousands)	
June 30, 2010				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 19,181	$ 19,181
Noncurrent commodity contracts	Deferred charges and other assets	—	3,893	3,893
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(33,480)	(33,480)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(5,100)	(5,100)
Total		—	(15,506)	(15,506)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	1,048	23,299	24,347
Noncurrent commodity contracts	Deferred charges and other assets	46	2,482	2,528
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(21,209)	(12,254)	(33,463)
Noncurrent commodity contracts	Deferred credits and other liabilities	(275)	(231)	(506)
Total		(20,390)	13,296	(7,094)
Total Financial Instruments		$(20,390)	$ (2,210)	$(22,600)

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

	Balance Sheet Location	Natural Gas Distribution	Natural Gas Marketing[1]	Total
		(In thousands)		
September 30, 2009				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 53,526	$ 53,526
Noncurrent commodity contracts	Deferred charges and other assets	—	6,800	6,800
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(47,146)	(47,146)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(999)	(999)
Total		—	12,181	12,181
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	4,395	27,559	31,954
Noncurrent commodity contracts	Deferred charges and other assets	1,620	7,964	9,584
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(20,181)	(19,657)	(39,838)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,349)	(1,349)
Total		(14,166)	14,517	351
Total Financial Instruments		$(14,166)	$ 26,698	$ 12,532

[1] Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our condensed consolidated income statement, by operating segment, as applicable, for the three and nine months ended June 30, 2010 and 2009.

Hedge ineffectiveness for our natural gas marketing and pipeline storage and other segments is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended June 30, 2010 and 2009 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $3.8 million and $0.2 million. For the nine months ended June 30, 2010 and 2009 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $44.2 million and $24.7 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and nine months ended June 30, 2010 and 2009 is presented below.

	Three Months Ended June 30, 2010		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ (9,923)	$ (602)	$(10,525)
Fair value adjustment for natural gas inventory designated as the hedged item	13,654	1,024	14,678
Total impact on revenue	$ 3,731	$ 422	$ 4,153
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (235)	$ —	$ (235)
Timing ineffectiveness	3,966	422	4,388
	$ 3,731	$ 422	$ 4,153

	Three Months Ended June 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$2,710	$1,390	$4,100
Fair value adjustment for natural gas inventory designated as the hedged item	3,929	(741)	3,188
Total impact on revenue	$6,639	$ 649	$7,288
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 678	$ —	$ 678
Timing ineffectiveness	5,961	649	6,610
	$6,639	$ 649	$7,288

	Nine Months Ended June 30, 2010		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$18,820	$1,476	$20,296
Fair value adjustment for natural gas inventory designated as the hedged item	21,997	4,198	26,195
Total impact on revenue	$40,817	$5,674	$46,491
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (684)	$ —	$ (684)
Timing ineffectiveness	41,501	5,674	47,175
	$40,817	$5,674	$46,491

	Nine Months Ended June 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 48,263	$ 7,435	$ 55,698
Fair value adjustment for natural gas inventory designated as the hedged item	(26,493)	(2,731)	(29,224)
Total impact on revenue	$ 21,770	$ 4,704	$ 26,474
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 4,958	$ —	$ 4,958
Timing ineffectiveness	16,812	4,704	21,516
	$ 21,770	$ 4,704	$ 26,474

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2010 and 2009 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized or will realize when the underlying physical and financial transactions are settled.

	Three Months Ended June 30, 2010			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)		
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(8,523)	$—	$(8,523)
Loss arising from ineffective portion of commodity contracts	—	(350)	—	(350)
Total impact on revenue	—	(8,873)	—	(8,873)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(669)	—	—	(669)
Total Impact from Cash Flow Hedges	$(669)	$(8,873)	$—	$(9,542)

	Three Months Ended June 30, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(36,669)	$(2,503)	$(39,172)
Loss arising from ineffective portion of commodity contracts	—	(7,120)	—	(7,120)
Total impact on revenue	—	(43,789)	(2,503)	(46,292)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(863)	—	—	(863)
Total Impact from Cash Flow Hedges	$(863)	$(43,789)	$(2,503)	$(47,155)

	Nine Months Ended June 30, 2010			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(43,079)	$2,883	$(40,196)
Loss arising from ineffective portion of commodity contracts	—	(2,307)	—	(2,307)
Total impact on revenue	—	(45,386)	2,883	(42,503)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,008)	—	—	(2,008)
Total Impact from Cash Flow Hedges	$(2,008)	$(45,386)	$2,883	$(44,511)

	Nine Months Ended June 30, 2009			
	Natural Gas Distribution	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
	(In thousands)			
Gain (loss) reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(142,986)	$25,213	$(117,773)
Loss arising from ineffective portion of commodity contracts	—	(1,748)	—	(1,748)
Total impact on revenue	—	(144,734)	25,213	(119,521)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(3,401)	—	—	(3,401)
Total Impact from Cash Flow Hedges	$(3,401)	$(144,734)	$25,213	$(122,922)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and nine months ended June 30, 2010 and 2009. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ —	$ —	$ —	$ 1,221
Forward commodity contracts	2,722	2,041	(19,829)	(78,220)
Recognition of losses in earnings due to settlements:				
Treasury lock agreements	422	543	1,265	1,963
Forward commodity contracts	5,199	23,895	24,519	71,841
Total other comprehensive income (loss) from hedging, net of tax[1]	$8,343	$26,479	$ 5,955	$ (3,195)

[1] Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Deferred losses recorded in AOCI associated with our treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2010:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,687)	$ (7,081)	$ (8,768)
Thereafter	(4,546)	(3,375)	(7,921)
Total[1]	$(6,233)	$(10,456)	$(16,689)

[1] Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2010 and 2009 is presented below. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related

costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
	(In thousands)			
Natural gas marketing commodity contracts	$ (6)	$ 6,167	$12,457	$12,928
Pipeline, storage and other commodity contracts	704	(6,853)	536	(6,753)
Total impact on revenue	$698	$ (686)	$12,993	$ 6,175

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the three and nine months ended June 30, 2010, there were no changes in these methods.

Effective October 1, 2009, the authoritative guidance related to nonrecurring fair value measurements became effective for us with respect to asset retirement obligations, most nonfinancial assets and liabilities that may be acquired in a business combination and impairment analyses performed for nonfinancial assets. The adoption of the FASB's fair value guidance for the reporting of these nonrecurring fair value measurements did not have a material impact on our financial position, results of operations or cash flows for the three and nine months ended June 30, 2010.

Although fair value measurements also apply to the valuation of our pension and post-retirement plan assets, the current fair value disclosure requirements are not applicable to our pension and post-retirement plan assets. Accordingly, these plan assets are not included in the tabular disclosures below. However, similar disclosures about fair value measurements for our pension and post-retirement plan assets will appear in our Form 10-K for the year ending September 30, 2010.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010 and

September 30, 2009. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	June 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,094	$ —	$ —	$ 1,094
Natural gas marketing segment	10,902	37,952	—	(27,266)	21,588
Total financial instruments	10,902	39,046	—	(27,266)	22,682
Hedged portion of gas stored underground					
Natural gas marketing segment	84,723	—	—	—	84,723
Pipeline, storage and other segment[3]	7,112	—	—	—	7,112
Total gas stored underground	91,835	—	—	—	91,835
Available-for-sale securities	38,972	—	—	—	38,972
Total assets	$141,709	$39,046	$ —	$(27,266)	$153,489
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$21,484	$ —	$ —	$ 21,484
Natural gas marketing segment	29,045	22,019	—	(45,283)	5,781
Total liabilities	$ 29,045	$43,503	$ —	$(45,283)	$ 27,265

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	September 30, 2009
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 6,015	$ —	$ —	$ 6,015
Natural gas marketing segment	34,281	61,568	—	(56,186)	39,663
Total financial instruments	34,281	67,583	—	(56,186)	45,678
Hedged portion of gas stored underground					
Natural gas marketing segment	47,967	—	—	—	47,967
Pipeline, storage and other segment[3]	6,789	—	—	—	6,789
Total gas stored underground	54,756	—	—	—	54,756
Available-for-sale securities	41,699	—	—	—	41,699
Total assets	$130,736	$67,583	$ —	$(56,186)	$142,133
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$20,181	$ —	$ —	$ 20,181
Natural gas marketing segment	48,268	20,883	—	(67,850)	1,301
Total liabilities	$ 48,268	$41,064	$ —	$(67,850)	$ 21,482

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and authoritative accounting literature. In addition, as of June 30, 2010 and September 30, 2009 we had $18.0 million and $11.7 million of cash held in margin accounts used to collateralize certain financial instruments which has been reflected as a financial instrument asset.

(3) Our pipeline, storage and other segment uses financial instruments acquired from AEM on the same terms that AEM received from an independent counterparty. On a consolidated basis, these financial instruments are reported in the natural gas marketing segment; however, the underlying hedged item is reported in the pipeline, storage and other segment.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of June 30, 2010:

	June 30, 2010
	(In thousands)
Carrying Amount	$2,172,761
Fair Value	$2,406,975

5. Debt

Long-term debt

Long-term debt at June 30, 2010 and September 30, 2009 consisted of the following:

	June 30, 2010	September 30, 2009
	(In thousands)	
Unsecured 7.375% Senior Notes, due May 2011	$ 350,000	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 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
Rental property term note due in installments through 2013	458	524
Total long-term debt	2,172,761	2,172,827
Less:		
Original issue discount on unsecured senior notes and debentures	(3,084)	(3,296)
Current maturities	(360,131)	(131)
	$1,809,546	$2,169,400

As noted above, our Unsecured 7.375% Senior Notes will mature in May 2011 and our Series A, 1995-2, 6.27% medium term notes will mature in December 2010; accordingly, these have been classified within the current maturities of long-term debt.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. At June 30, 2010, there were no short-term debt borrowings outstanding. At September 30, 2009, there was a total of $72.6 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $800 million of working capital funding. The first facility is a five-year $566.7 million unsecured facility, expiring December 15, 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At June 30, 2010, there were no borrowings under this facility nor was there any commercial paper outstanding.

The second facility is a $200 million unsecured 364-day facility that expires October 22, 2010. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.75 percent to 3.00 percent, based on the Company's credit ratings. At June 30, 2010, there were no borrowings outstanding under this facility.

The third facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At June 30, 2010, there were no borrowings outstanding under this facility. This facility expired on March 31, 2010 and was replaced with a $25 million unsecured facility effective April 1, 2010 that also bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2010, our total-debt-to-total-capitalization ratio, as defined, was 51 percent. In addition, both the interest margin over the Eurodollar rate and the fees that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, the Company has a $200 million intercompany revolving credit facility provided by AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility, (ii) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the 364-day revolving credit facility or (iii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2010. There was $67.4 million outstanding under this facility at June 30, 2010.

Nonregulated Operations

On December 10, 2009, AEM and the participating banks amended and restated AEM's $450 million committed revolving credit facility extending it to December 9, 2010.

AEM uses this facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. At AEM's option, borrowings made under the credit facility

are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; and (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent plus 0.50 percent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; and (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 2.250 percent to 2.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $17 million to $27 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At June 30, 2010, there were no borrowings outstanding under this credit facility. However, at June 30, 2010, AEM letters of credit totaling $22.7 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $159.6 million at June 30, 2010.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At June 30, 2010, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.12 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $75 million to $112.5 million. As defined in the financial covenants, at June 30, 2010, AEM's net working capital was $166.8 million and its tangible net worth was $179.4 million.

To supplement borrowings under this facility, AEM has a $300 million intercompany demand credit facility with AEH, which bears interest at the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Amounts outstanding under this facility are subordinated to AEM's committed credit facility. There were no borrowings outstanding under this facility at June 30, 2010.

Finally, AEH has a $200 million intercompany demand credit facility with AEC, which bears interest at greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved the new facility through December 31, 2010. There were no borrowings outstanding under this facility at June 30, 2010.

Shelf Registration

On March 31, 2010, we filed a registration statement with the SEC to issue, from time to time, up to $1.3 billion in common stock and/or debt securities available for issuance.

We received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under the new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of June 30, 2010. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

As discussed in Note 2, since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share as of October 1, 2009. The Company's non-vested restricted stock and restricted stock units, granted under the 1998 Long-Term Incentive Plan, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. The presentation of earnings per share for previously reported periods has been adjusted to reflect the retrospective adoption of this

standard. Basic and diluted earnings per share for the three and nine months ended June 30, 2010 and 2009 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
	(In thousands, except per share amounts)			
Basic Earnings Per Share				
Net income (loss)	$ (3,154)	$ 1,964	$204,302	$206,930
Less: Income (loss) allocated to participating securities	(38)	13	2,082	1,955
Net income (loss) available to common shareholders	$ (3,116)	$ 1,951	$202,220	$204,975
Basic weighted average shares outstanding	92,648	91,338	92,513	90,940
Net income (loss) per share — Basic	$ (0.03)	$ 0.02	$ 2.19	$ 2.25
Diluted Earnings Per Share				
Net income (loss) available to common shareholders	$ (3,116)	$ 1,951	$202,220	$204,975
Effect of dilutive stock options and other shares	—	(1)	4	4
Net income (loss) available to common shareholders	$ (3,116)	$ 1,950	$202,224	$204,979
Basic weighted average shares outstanding	92,648	91,338	92,513	90,940
Additional dilutive stock options and other shares	—	314	343	306
Diluted weighted average shares outstanding	92,648	91,652	92,856	91,246
Net income (loss) per share — Diluted	$ (0.03)	$ 0.02	$ 2.18	$ 2.25

There were approximately 333,000 stock options that were excluded from the calculation of diluted earnings per share for the three months ended June 30, 2010 as their inclusion in the computation would be anti-dilutive.

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the nine months ended June 30, 2010 as their exercise price was less than the average market price of the common stock during that period. There were approximately 33,000 and 132,000 out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2009.

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, 2010 and 2009 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 3,993	$ 3,703	$3,360	$2,946
Interest cost	6,524	7,554	3,018	3,520
Expected return on assets	(6,320)	(6,238)	(615)	(573)
Amortization of transition asset	—	—	377	378
Amortization of prior service cost	(193)	(183)	(375)	—
Amortization of actuarial loss	2,822	955	93	—
Net periodic pension cost	$ 6,826	$ 5,791	$5,858	$6,271

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 11,982	$ 11,109	$10,077	$ 8,838
Interest cost	19,569	22,662	9,051	10,560
Expected return on assets	(18,960)	(18,714)	(1,845)	(1,719)
Amortization of transition asset	—	—	1,134	1,134
Amortization of prior service cost	(582)	(549)	(1,125)	—
Amortization of actuarial loss	8,469	2,865	282	—
Net periodic pension cost	$ 20,478	$ 17,373	$17,574	$18,813

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2010 and 2009 are as follows:

	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
Discount rate	5.52%	7.57%	5.52%	7.57%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2010. Based upon this valuation, we will not be required to contribute to our pension plans during fiscal 2010.

We contributed $9.1 million to our other post-retirement benefit plans during the nine months ended June 30, 2010. We expect to contribute a total of approximately $12 million to these plans during fiscal 2010.

For our Supplemental Executive Retirement Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of June 30, 2010:				
Domestic equity mutual funds	$29,379	$3,212	$ —	$32,591
Foreign equity mutual funds	4,753	205	(47)	4,911
Money market funds	1,470	—	—	1,470
	$35,602	$3,417	$(47)	$38,972
As of September 30, 2009:				
Domestic equity mutual funds	$26,012	$3,012	$ —	$29,024
Foreign equity mutual funds	4,047	893	—	4,940
Money market funds	7,735	—	—	7,735
	$37,794	$3,905	$ —	$41,699

During the three and nine months ended June 30, 2009, we recorded a $3.3 million and $5.4 million noncash charge to impair certain available-for-sale investments due to the deterioration of the financial markets and the uncertainty of a full recovery.

At June 30, 2010, we maintained an investment in one foreign equity mutual fund that was in an unrealized loss position. This fund has been in an unrealized loss position for less than 12 months as of June 30, 2010. Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based on our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other than temporary as of June 30, 2010.

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 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2010. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2010, AEM was committed to purchase 77.8 Bcf within one year, 11.4 Bcf within one to three years and 2.1 Bcf after three years under indexed contracts. AEM is committed to purchase 2.1 Bcf within one year, 0.8 Bcf within one to three years and 0.1 Bcf after three years under fixed price contracts with prices ranging from $4.03 to $6.36 per Mcf. Purchases under these contracts totaled $315.6 million and $256.0 million for the three months ended June 30, 2010 and 2009 and $1,208.4 million and $1,215.0 million for the nine months ended June 30, 2010 and 2009.

Our natural gas distribution divisions, except for our 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 and fixed prices. The estimated commitments under these contracts as of June 30, 2010 are as follows (in thousands):

2010	$ 44,248
2011	265,224
2012	87,138
2013	6,705
2014	2,293
Thereafter	—
	$405,608

Our natural gas marketing and pipeline, storage and other segments maintain long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2010.

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

After responding to two sets of data requests received from the Commission, the Commission agreed to allow us to conduct our own internal investigation into compliance with the Commission's rules. We have

completed our internal investigation and submitted the results to the Commission. During our investigation, we identified certain non-compliant transactions, and we continue to fully cooperate with the Commission as we work to resolve this matter. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

As of June 30, 2010, rate cases were in progress in our Kansas and Missouri service areas and annual rate filing mechanisms were in progress in our Mid-Tex, West Texas and Louisiana service areas. In addition, there was a GRIP filing in progress in our Mid-Tex Division along with other rate activity in our Georgia service area. We recently reached a tentative agreement to extend the rate review mechanism (RRM) for our West Texas Cities service area in our West Texas Division and are in discussions to extend the RRM in our Mid-Tex Division and in our Amarillo and Lubbock service areas in our West Texas Division. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. We are committed to replacing the steel service lines on an accelerated schedule to ensure the safety and reliability of our distribution system, and as part of this commitment, we support the objectives of the rulemaking outlined by the Texas Railroad Commission (RRC) for steel service-line replacements statewide. The RRC is not scheduled to consider a formal rulemaking for this program until August 2010. Due to the preliminary status of the rulemaking process, we cannot accurately anticipate the impact this rule would have on the Company or the expected cost of the replacement program.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the nine months ended June 30, 2010, there were no material changes in our concentration of credit risk.

10. Segment Information

As discussed in Note 1 above, we operate the Company through the following four segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which includes our nonregulated natural gas gathering transmission and storage services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in varying regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2009. 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, 2010 and 2009 by segment are presented in the following tables:

	Three Months Ended June 30, 2010					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$405,049	$22,796	$336,408	$6,004	$ —	$770,257
Intersegment revenues	222	22,161	84,998	2,192	(109,573)	—
	405,271	44,957	421,406	8,196	(109,573)	770,257
Purchased gas cost	208,378	—	415,101	2,730	(109,180)	517,029
Gross profit	196,893	44,957	6,305	5,466	(393)	253,228
Operating expenses						
Operation and maintenance	89,112	16,050	6,486	2,093	(393)	113,348
Depreciation and amortization	46,981	5,171	426	710	—	53,288
Taxes, other than income	48,521	3,010	555	397	—	52,483
Total operating expenses	184,614	24,231	7,467	3,200	(393)	219,119
Operating income (loss)	12,279	20,726	(1,162)	2,266	—	34,109
Miscellaneous income (expense)	(124)	94	147	670	(1,637)	(850)
Interest charges	29,042	7,667	1,767	451	(1,637)	37,290
Income (loss) before income taxes	(16,887)	13,153	(2,782)	2,485	—	(4,031)
Income tax expense (benefit)	(5,985)	4,688	(683)	1,103	—	(877)
Net income (loss)	$ (10,902)	$ 8,465	$ (2,099)	$1,382	$ —	$ (3,154)
Capital expenditures	$106,394	$22,964	$ 176	$ 186	$ —	$129,720

	Three Months Ended June 30, 2009					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$386,774	$29,558	$358,458	$5,985	$ —	$780,775
Intersegment revenues	211	19,787	95,046	2,241	(117,285)	—
	386,985	49,345	453,504	8,226	(117,285)	780,775
Purchased gas cost	195,303	—	438,482	4,212	(116,862)	521,135
Gross profit	191,682	49,345	15,022	4,014	(423)	259,640
Operating expenses						
Operation and maintenance	89,534	13,784	6,445	1,641	(509)	110,895
Depreciation and amortization	47,928	5,066	392	795	—	54,181
Taxes, other than income	44,014	2,569	628	366	—	47,577
Asset impairments	2,823	370	90	21	—	3,304
Total operating expenses	184,299	21,789	7,555	2,823	(509)	215,957
Operating income	7,383	27,556	7,467	1,191	86	43,683
Miscellaneous income	2,167	615	71	2,319	(3,953)	1,219
Interest charges	32,798	8,152	4,020	408	(3,867)	41,511
Income (loss) before income taxes	(23,248)	20,019	3,518	3,102	—	3,391
Income tax expense (benefit)	(8,307)	7,065	1,419	1,250	—	1,427
Net income (loss)	$ (14,941)	$12,954	$ 2,099	$1,852	$ —	$ 1,964
Capital expenditures	$ 86,861	$28,216	$ 82	$5,837	$ —	$120,996

	Nine Months Ended June 30, 2010					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,573,471	$ 64,281	$1,343,214	$22,409	$ —	$4,003,375
Intersegment revenues	682	82,717	314,615	6,460	(404,474)	—
	2,574,153	146,998	1,657,829	28,869	(404,474)	4,003,375
Purchased gas cost	1,697,248	—	1,585,259	5,732	(403,262)	2,884,977
Gross profit	876,905	146,998	72,570	23,137	(1,212)	1,118,398
Operating expenses						
Operation and maintenance	272,687	53,877	21,772	7,174	(1,212)	354,298
Depreciation and amortization	141,586	15,395	1,261	1,965	—	160,207
Taxes, other than income	142,042	9,226	2,237	1,143	—	154,648
Total operating expenses	556,315	78,498	25,270	10,282	(1,212)	669,153
Operating income	320,590	68,500	47,300	12,855	—	449,245
Miscellaneous income (expense)	1,309	117	642	2,103	(5,241)	(1,070)
Interest charges	87,976	23,589	6,965	2,291	(5,241)	115,580
Income before income taxes	233,923	45,028	40,977	12,667	—	332,595
Income tax expense	90,646	16,039	16,506	5,102	—	128,293
Net income	$ 143,277	$ 28,989	$ 24,471	$ 7,565	$ —	$ 204,302
Capital expenditures	$ 302,621	$ 56,786	$ 629	$ 2,313	$ —	$ 362,349

	Nine Months Ended June 30, 2009					
	Natural Gas Distribution	Regulated Transmission Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$2,672,742	$ 91,877	$1,524,438	$29,456	$ —	$4,318,513
Intersegment revenues	631	71,384	425,219	7,490	(504,724)	—
	2,673,373	163,261	1,949,657	36,946	(504,724)	4,318,513
Purchased gas cost	1,816,227	—	1,881,068	9,771	(503,456)	3,203,610
Gross profit	857,146	163,261	68,589	27,175	(1,268)	1,114,903
Operating expenses						
Operation and maintenance	276,462	58,448	27,228	4,700	(1,526)	365,312
Depreciation and amortization	142,608	15,027	1,189	1,933	—	160,757
Taxes, other than income	139,861	7,929	1,667	571	—	150,028
Asset impairments	4,599	602	146	35	—	5,382
Total operating expenses	563,530	82,006	30,230	7,239	(1,526)	681,479
Operating income	293,616	81,255	38,359	19,936	258	433,424
Miscellaneous income (expense)	6,123	1,713	490	6,540	(15,513)	(647)
Interest charges	94,506	23,580	11,383	1,821	(15,255)	116,035
Income before income taxes	205,233	59,388	27,466	24,655	—	316,742
Income tax expense	68,465	19,308	11,444	10,595	—	109,812
Net income	$ 136,768	$ 40,080	$ 16,022	$14,060	$ —	$ 206,930
Capital expenditures	$ 260,482	$ 61,579	$ 199	$20,066	$ —	$ 342,326

Balance sheet information at June 30, 2010 and September 30, 2009 by segment is presented in the following tables:

	June 30, 2010					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,872,364	$715,411	$ 7,233	$ 74,035	$ —	$4,669,043
Investment in subsidiaries	613,652	—	(2,096)	—	(611,556)	—
Current assets						
Cash and cash equivalents	32,777	—	65,446	82,160	—	180,383
Assets from risk management activities	1,048	—	17,102	6	(421)	17,735
Other current assets	424,374	16,194	245,605	79,746	(90,064)	675,855
Intercompany receivables	560,553	—	—	108,687	(669,240)	—
Total current assets	1,018,752	16,194	328,153	270,599	(759,725)	873,973
Intangible assets	—	—	990	—	—	990
Goodwill	571,592	132,300	24,282	10,429	—	738,603
Noncurrent assets from risk management activities	46	—	4,950	—	(49)	4,947
Deferred charges and other assets	269,850	10,877	1,259	16,108	—	298,094
	$6,346,256	$874,782	$364,771	$371,171	$(1,371,330)	$6,585,650
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,313,730	$200,190	$ 73,285	$340,177	$ (613,652)	$2,313,730
Long-term debt	1,809,219	—	—	327	—	1,809,546
Total capitalization	4,122,949	200,190	73,285	340,504	(613,652)	4,123,276
Current liabilities						
Current maturities of long-term debt	360,000	—	—	131	—	360,131
Short-term debt	67,435	—	—	—	(67,435)	—
Liabilities from risk management activities	21,209	—	1,929	415	(421)	23,132
Other current liabilities	450,488	10,484	167,203	16,854	(20,533)	624,496
Intercompany payables	—	544,307	124,933	—	(669,240)	—
Total current liabilities	899,132	554,791	294,065	17,400	(757,629)	1,007,759
Deferred income taxes	636,745	115,117	(7,190)	11,050	—	755,722
Noncurrent liabilities from risk management activities	275	—	3,858	49	(49)	4,133
Regulatory cost of removal obligation	314,708	—	—	—	—	314,708
Deferred credits and other liabilities	372,447	4,684	753	2,168	—	380,052
	$6,346,256	$874,782	$364,771	$371,171	$(1,371,330)	$6,585,650

	September 30, 2009					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,703,471	$672,829	$ 7,112	$ 55,691	$ —	$4,439,103
Investment in subsidiaries	547,936	—	(2,096)	—	(545,840)	—
Current assets						
Cash and cash equivalents	23,655	—	87,266	282	—	111,203
Assets from risk management activities	4,395	—	27,424	2,765	(2,941)	31,643
Other current assets	499,155	17,017	157,846	112,551	(100,475)	686,094
Intercompany receivables	552,408	—	—	128,104	(680,512)	—
Total current assets	1,079,613	17,017	272,536	243,702	(783,928)	828,940
Intangible assets	—	—	1,461	—	—	1,461
Goodwill	571,592	132,300	24,282	10,429	—	738,603
Noncurrent assets from risk management activities	1,620	—	12,415	6	(6)	14,035
Deferred charges and other assets	290,327	11,932	1,065	18,300	—	321,624
	$6,194,559	$834,078	$316,775	$328,128	$(1,329,774)	$6,343,766
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$2,176,761	$171,200	$ 83,354	$293,382	$ (547,936)	$2,176,761
Long-term debt	2,169,007	—	—	393	—	2,169,400
Total capitalization	4,345,768	171,200	83,354	293,775	(547,936)	4,346,161
Current liabilities						
Current maturities of long-term debt	—	—	—	131	—	131
Short-term debt	158,942	—	—	—	(86,392)	72,550
Liabilities from risk management activities	20,181	—	4,060	182	(2,941)	21,482
Other current liabilities	510,749	9,251	116,078	19,167	(11,987)	643,258
Intercompany payables	—	557,190	123,322	—	(680,512)	—
Total current liabilities	689,872	566,441	243,460	19,480	(781,832)	737,421
Deferred income taxes	477,352	92,250	(10,675)	12,013	—	570,940
Noncurrent liabilities from risk management activities	—	—	6	—	(6)	—
Regulatory cost of removal obligation	321,086	—	—	—	—	321,086
Deferred credits and other liabilities	360,481	4,187	630	2,860	—	368,158
	$6,194,559	$834,078	$316,775	$328,128	$(1,329,774)	$6,343,766

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of June 30, 2010, the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2010 and 2009, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2010 and 2009. 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, 2009, 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, 2009, 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, 2009, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
August 5, 2010

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, 2009.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties, which are discussed in more detail in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business; natural disasters, terrorist activities or other events; and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

We operate the Company through the following four segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division,
- the *natural gas marketing segment*, which includes a variety of nonregulated natural gas management services and
- the *pipeline, storage and other segment*, which is comprised of our nonregulated natural gas gathering, transmission and storage services.

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, the 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 fiscal year ended September 30, 2009 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2010.

RESULTS OF OPERATIONS

Due to the seasonality of our distribution business, we typically incur a net loss in our fiscal third quarter. For the three months ended June 30, 2010, we reported a net loss of $3.2 million, or $0.03 per diluted share compared with net income of $2.0 million, or $0.02 per diluted share in the prior-year quarter. The net loss for the three months ended June 30, 2010 includes noncash, unrealized net losses of $11.1 million, or $0.12 per diluted share compared with net gains of $7.0 million, or $0.08 per diluted share for the three months ended June 30, 2009. Quarter over quarter, lower net losses in our natural gas distribution operations offset lower earnings in our regulated transmission and storage segment associated with a 29 percent decrease in consolidated throughput due to reduced demand and basis spreads. Our nonregulated operations benefited from significantly higher storage and trading margins compared with the prior-year quarter, which more than offset the impact of an 11 percent quarter-over-quarter decrease in sales volumes in our natural gas marketing segment.

We reported net income of $204.3 million, or $2.18 per diluted share for the nine months ended June 30, 2010 compared with net income of $206.9 million, or $2.25 per diluted share in the prior-year period. Unrealized losses in our nonregulated operations during the current period reduced net income by $6.2 million or $0.07 per diluted share compared with net losses recorded in the prior-year period of $9.9 million, or $0.11 per diluted share. Regulated operations contributed 84 percent of our net income during this period with our nonregulated operations contributing the remaining 16 percent. Net income in both periods was impacted by nonrecurring items. The current year period includes the positive impact of a state sales tax refund of $4.5 million, or $0.05 per diluted share. Net income in the prior-year period included the net positive impact of several one-time items totaling $17.3 million, or $0.19 per diluted share related to the following pre-tax amounts:

- $11.3 million related to a favorable one-time tax benefit.
- $7.8 million related to the favorable impact of an update to the estimate for unbilled accounts.
- $7.0 million favorable impact of the reversal of estimated uncollectible gas costs.
- $5.4 million unfavorable impact of a non-cash impairment charge related to available-for-sale securities in our Supplemental Executive Retirement Plan.

During the nine months ended June 30, 2010, colder-than-normal weather and recent improvements in rate designs in our natural gas distribution segment partially offset the decline in demand for natural gas, which contributed to a 26 percent year-over-year decrease in consolidated throughput in our regulated transmission and storage segment and a 5 percent year-over-year decrease in consolidated sales volumes in our natural gas marketing segment.

During the year, we continued to successfully access the capital markets and received updated debt ratings from three rating agencies. In October 2009, we renewed a $200 million 364-day committed credit facility and in December 2009 we renewed a $450 million 364-day committed credit facility for our nonregulated operations. In June 2010, Fitch upgraded our rating outlook from stable to positive and affirmed the existing credit rating on our senior unsecured debt and commercial paper. In March 2010, Moody's upgraded our rating outlook from stable to positive and affirmed the existing credit rating on our senior long-term debt and commercial paper while S&P affirmed our rating outlook as stable and our senior long-term debt credit rating. The new credit facilities should help ensure we have sufficient liquidity to fund our working capital needs, while our credit ratings should help us continue to obtain financing at a reasonable cost in the future.

On July 1, 2010, we entered into an accelerated share repurchase program with Goldman Sachs & Co. as part of our ongoing efforts to improve shareholder value. The shares that will be repurchased under this program will offset the dilutive impact of stock grants made under our various employee and director incentive compensation plans. It is anticipated that the impact of the program will add $0.01 to $0.02 to fiscal 2010 diluted earnings per share.

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2010 and 2009:

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
	(In thousands, except per share data)			
Operating revenues	$770,257	$780,775	$4,003,375	$4,318,513
Gross profit	253,228	259,640	1,118,398	1,114,903
Operating expenses	219,119	215,957	669,153	681,479
Operating income	34,109	43,683	449,245	433,424
Miscellaneous income (expense)	(850)	1,219	(1,070)	(647)
Interest charges	37,290	41,511	115,580	116,035
Income (loss) before income taxes	(4,031)	3,391	332,595	316,742
Income tax expense (benefit)	(877)	1,427	128,293	109,812
Net income (loss)	$ (3,154)	$ 1,964	$ 204,302	$ 206,930
Diluted net income (loss) per share	$ (0.03)	$ 0.02	$ 2.18	$ 2.25

Our consolidated net income (loss) during the three and nine months ended June 30, 2010 and 2009 was earned in each of our business segments as follows:

	Three Months Ended June 30		
	2010	2009	Change
	(In thousands)		
Natural gas distribution segment	$(10,902)	$(14,941)	$ 4,039
Regulated transmission and storage segment	8,465	12,954	(4,489)
Natural gas marketing segment	(2,099)	2,099	(4,198)
Pipeline, storage and other segment	1,382	1,852	(470)
Net income (loss)	$ (3,154)	$ 1,964	$(5,118)

	Nine Months Ended June 30		
	2010	2009	Change
	(In thousands)		
Natural gas distribution segment	$143,277	$136,768	$ 6,509
Regulated transmission and storage segment	28,989	40,080	(11,091)
Natural gas marketing segment	24,471	16,022	8,449
Pipeline, storage and other segment	7,565	14,060	(6,495)
Net income	$204,302	$206,930	$ (2,628)

The following tables segregate our consolidated net income (loss) and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended June 30		
	2010	2009	Change
	(In thousands, except per share data)		
Regulated operations	$(2,437)	$(1,987)	$ (450)
Nonregulated operations	(717)	3,951	(4,668)
Consolidated net income (loss)	$(3,154)	$ 1,964	$(5,118)
Diluted EPS from regulated operations	$ (0.02)	$ (0.02)	$ —
Diluted EPS from nonregulated operations	(0.01)	0.04	(0.05)
Consolidated diluted EPS	$ (0.03)	$ 0.02	$ (0.05)

	Nine Months Ended June 30		
	2010	2009	Change
	(In thousands, except per share data)		
Regulated operations	$172,266	$176,848	$(4,582)
Nonregulated operations	32,036	30,082	1,954
Consolidated net income	$204,302	$206,930	$(2,628)
Diluted EPS from regulated operations	$ 1.84	$ 1.92	$ (0.08)
Diluted EPS from nonregulated operations	0.34	0.33	0.01
Consolidated diluted EPS	$ 2.18	$ 2.25	$ (0.07)

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

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

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income. Prior to January 1, 2009, timing differences existed between the recognition of revenue for franchise fees collected from our customers and the recognition of expense of franchise taxes. These timing differences had a significant temporary effect on operating income in periods with volatile gas prices, particularly in our Mid-Tex Division. Beginning January 1, 2009, changes in our franchise fee agreements in our Mid-Tex Division became effective, which have significantly reduced the impact of this timing difference. Although this timing difference will still be present for gross receipts taxes, the timing differences described above have been and should continue to be less significant.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Three Months Ended June 30, 2010 compared with Three Months Ended June 30, 2009

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2010 and 2009 are presented below.

	Three Months Ended June 30		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Gross profit	$196,893	$191,682	$ 5,211
Operating expenses	184,614	184,299	315
Operating income	12,279	7,383	4,896
Miscellaneous income (expense)	(124)	2,167	(2,291)
Interest charges	29,042	32,798	(3,756)
Loss before income taxes	(16,887)	(23,248)	6,361
Income tax benefit	(5,985)	(8,307)	2,322
Net loss	$ (10,902)	$ (14,941)	$ 4,039
Consolidated natural gas distribution sales volumes — MMcf	36,339	40,081	(3,742)
Consolidated natural gas distribution transportation volumes — MMcf	29,589	29,597	(8)
Total consolidated natural gas distribution throughput — MMcf	65,928	69,678	(3,750)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.46	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.73	$ 4.87	$ 0.86

The following table shows our operating income (loss) by natural gas distribution division, in order of total customers served, for the three months ended June 30, 2010 and 2009. The presentation of our natural gas distribution operating income (loss) is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30		
	2010	2009	Change
	(In thousands)		
Mid-Tex	$ (2,179)	$(3,598)	$ 1,419
Kentucky/Mid-States	5,055	2,931	2,124
Louisiana	6,537	5,459	1,078
West Texas	(104)	1,010	(1,114)
Mississippi	950	(585)	1,535
Colorado-Kansas	1,762	1,247	515
Other	258	919	(661)
Total	$12,279	$ 7,383	$ 4,896

The $5.2 million increase in natural gas distribution gross profit primarily reflects a net increase of $5.5 million in rate adjustments, primarily in the Mid-Tex, Louisiana, West Texas and Mississippi service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments increased $0.3 million. This increase was primarily due to an increase in state gross receipts taxes and ad valorem taxes, partially offset by a $2.8 million decrease due to the absence of an impairment of available-for-sale securities recorded in the prior year.

Nine Months Ended June 30, 2010 compared with Nine Months Ended June 30, 2009

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2010 and 2009 are presented below.

	Nine Months Ended June 30		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Gross profit	$876,905	$857,146	$19,759
Operating expenses	556,315	563,530	(7,215)
Operating income	320,590	293,616	26,974
Miscellaneous income	1,309	6,123	(4,814)
Interest charges	87,976	94,506	(6,530)
Income before income taxes	233,923	205,233	28,690
Income tax expense	90,646	68,465	22,181
Net income	$143,277	$136,768	$ 6,509
Consolidated natural gas distribution sales volumes — MMcf	294,183	253,087	41,096
Consolidated natural gas distribution transportation volumes — MMcf	104,090	98,994	5,096
Total consolidated natural gas distribution throughput — MMcf	398,273	352,081	46,192
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.46	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.77	$ 7.18	$ (1.41)

The following table shows our operating income by natural gas distribution division, in order of total customers served, for the nine months ended June 30, 2010 and 2009. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2010	2009	Change
	(In thousands)		
Mid-Tex	$128,045	$129,454	$ (1,409)
Kentucky/Mid-States	53,858	49,360	4,498
Louisiana	42,775	39,825	2,950
West Texas	33,053	23,829	9,224
Mississippi	28,604	24,621	3,983
Colorado-Kansas	24,635	23,471	1,164
Other	9,620	3,056	6,564
Total	$320,590	$293,616	$26,974

The $19.8 million increase in natural gas distribution gross profit primarily reflects rate adjustments and increased throughput as follows:

- $27.9 million net increase in rate adjustments, primarily in the West Texas, Mid-Tex, Louisiana and Mississippi service areas.
- $10.8 million increase as a result of a 13 percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

These increases were partially offset by:

- $7.8 million decrease due to a non-recurring adjustment recorded in the prior-year period to update the estimate for gas delivered to customers but not yet billed to reflect base rate changes.
- $7.0 million decrease related to a prior year reversal of an accrual for estimated unrecoverable gas costs that did not recur in the current year.
- $1.8 million decrease due to a decrease in revenue-related taxes, primarily due to a decrease in revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $7.2 million, primarily due to the following:

- $7.4 million decrease due to a state sales tax reimbursement received in March 2010.
- $4.6 million decrease due to the absence of an impairment charge for available-for-sale securities recorded in the prior year.
- $1.6 million decrease in contract labor expenses.

These decreases were partially offset by:

- $5.1 million increase in employee-related expenses.
- $2.2 million increase in taxes, other than income.

Miscellaneous income decreased $4.8 million due to lower interest income. Interest charges decreased $6.5 million primarily due to lower short-term debt balances and interest rates.

Additionally, results for the nine months ended June 30, 2009, were favorably impacted by a one-time tax benefit of $10.5 million. During the second quarter of fiscal 2009, the Company completed a study of the calculations used to estimate its deferred tax rate, and concluded that revisions to these calculations to include more specific jurisdictional tax rates would result in a more accurate calculation of the tax rate at which deferred taxes would reverse in the future. Accordingly, the Company modified the tax rate used to calculate deferred taxes from 38 percent to an individual rate for each legal entity. These rates vary from 36-41 percent depending on the jurisdiction of the legal entity.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the nine months ended June 30, 2010 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $41.1 million resulting from ratemaking activity became effective in the nine months ended June 30, 2010 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Rate case filings	$15,831
GRIP filings	13,768
Annual rate filing mechanisms	8,905
Other rate activity	2,630
	$41,134

Additionally, the following ratemaking efforts were in progress during the third quarter of fiscal 2010 but had not been completed as of June 30, 2010.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado/Kansas	Rate Case[1]	Kansas	$ 6,015
Kentucky/Mid-States	PRP[2]	Georgia	764
	Rate Case[3]	Missouri	6,439
Louisiana	RSC[4]	LGS	4,296
Mid-Tex	GRIP[5][6]	Dallas & RRC	2,985
	Rate Review Mechanism (RRM)[7]	Settled Cities	56,827
West Texas	RRM[8]	WT Cities	4,243
	RRM[9]	Amarillo & Lubbock	2,388
			$83,957

(1) The Company, the Kansas Corporation Commission Staff and the Citizen's Utility Ratepayer Board reached a unanimous settlement for an increase in operating income of $3.9 million which the Commission approved, effective August 1, 2010.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(3) The Company, the Staff of the Missouri Public Service Commission, the Office of the Public Counsel, the Missouri Department of Natural Resources and Noranda Aluminum, Inc. reached a unanimous settlement

in July 2010 for an increase in operating income of $4.0 million. The settlement is subject to final Missouri Public Service Commission approval.

(4) The Louisiana Commission Staff recommended an increase of $3.9 million effective July 1, 2010, which the Commission accepted.

(5) Gas Reliability Infrastructure Program (GRIP) is a rate adjustment that allows utilities to recover additional invested capital without filing a rate case.

(6) This GRIP filing is based on a Mid-Tex System-wide basis and made concurrently with the City of Dallas and the Railroad Commission of Texas (RRC) for approval of their respective jurisdictional customers. The City of Dallas filing is currently on appeal at the RRC.

(7) The Company and representatives of the Settled Cities are currently in negotiations to settle the filing and extend the rate review mechanism (RRM) in our Mid-Tex Division.

(8) The Company and representatives of the West Texas Cities have reached a tentative settlement for a one-year extension of the RRM and an increase in operating income of $0.7 million. The settlement is subject to final authorization by each of the West Texas Cities.

(9) Consultant reports have been received for the RRM filing in Lubbock and discussions are ongoing regarding the final resolution. A tentative settlement for the Amarillo RRM has been reached which would result in an operating income increase of $1.2 million.

Rate Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2010 Rate Case Filings:			
Kentucky/Mid-States	Kentucky	$ 6,636	06/01/2010
	Georgia	2,935	03/31/2010
Mid-Tex	Texas[1]	2,963	01/26/2010
Colorado/Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$15,831	

(1) In its final order, the RRC approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Net of the GRIP 2008 rates that will be superseded, operating income will increase $0.2 million. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

GRIP Filings

GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. The following table summarizes our GRIP filings with effective dates during the nine months ended June 30, 2010.

Division	Calendar Year	Incremental Net Utility Plant Investment	Additional Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2010 GRIP:				
West Texas	2009	$ 19,158	$ 363	06/14/2010
Atmos Pipeline — Texas	2009	95,504	13,405	04/20/2010
Total 2010 GRIP		$114,662	$13,768	

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms (RRM) in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. We have recently reached a tentative agreement to extend the RRM for our West Texas Cities service area in our West Texas Division and are in discussions to extend the RRM in our Mid-Tex Division and in our Amarillo and Lubbock service areas in our West Texas Division. The following table summarizes filings made under our various annual rate filing mechanisms for the nine months ended June 30, 2010.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2010 Filings:				
Louisiana	TransLa	12/31/2009	$1,733	04/01/2010
Mississippi	Mississippi	06/30/2009	3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$8,905	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2010:

Division	Jurisdiction	Rate Activity	Increase in Operating Income	Effective Date
			(In thousands)	
2010 Other Rate Activity:				
Kentucky/Mid-States	Missouri	ISRS[(1)]	$ 563	03/02/2010
Colorado-Kansas	Kansas	Ad Valorem[(2)]	392	01/05/2010
	Kansas	GSRS[(3)]	766	12/12/2009
Kentucky/Mid-States	Georgia	PRP Surcharge	909	10/01/2009
Total 2010 Other Rate Activity			$2,630	

(1) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

(2) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in the Company's base rates.

(3) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, 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.

Three Months Ended June 30, 2010 compared with Three Months Ended June 30, 2009

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2010 and 2009 are presented below.

	Three Months Ended June 30		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 21,908	$ 19,507	$ 2,401
Third-party transportation	17,521	24,285	(6,764)
Storage and park and lend services	2,646	3,137	(491)
Other	2,882	2,416	466
Gross profit	44,957	49,345	(4,388)
Operating expenses	24,231	21,789	2,442
Operating income	20,726	27,556	(6,830)
Miscellaneous income	94	615	(521)
Interest charges	7,667	8,152	(485)
Income before income taxes	13,153	20,019	(6,866)
Income tax expense	4,688	7,065	(2,377)
Net income	$ 8,465	$ 12,954	$ (4,489)
Gross pipeline transportation volumes — MMcf	127,861	169,641	(41,780)
Consolidated pipeline transportation volumes — MMcf	100,770	141,556	(40,786)

The $4.4 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $3.6 million decrease due to decreased through-system volumes primarily associated with declines in basis differentials, electric generation demand and Barnett Shale activity.
- $3.5 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.

These decreases were partially offset by a $3.1 million increase associated with our GRIP filings.

Operating expenses increased $2.4 million primarily due to higher levels of pipeline maintenance activities.

Nine Months Ended June 30, 2010 compared with Nine Months Ended June 30, 2009

Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2010 and 2009 are presented below.

	Nine Months Ended June 30		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 81,833	$ 70,920	$ 10,913
Third-party transportation	49,098	73,497	(24,399)
Storage and park and lend services	7,924	8,151	(227)
Other	8,143	10,693	(2,550)
Gross profit	146,998	163,261	(16,263)
Operating expenses	78,498	82,006	(3,508)
Operating income	68,500	81,255	(12,755)
Miscellaneous income	117	1,713	(1,596)
Interest charges	23,589	23,580	9
Income before income taxes	45,028	59,388	(14,360)
Income tax expense	16,039	19,308	(3,269)
Net income	$ 28,989	$ 40,080	$ (11,091)
Gross pipeline transportation volumes — MMcf	478,075	555,169	(77,094)
Consolidated pipeline transportation volumes — MMcf	295,126	400,699	(105,573)

The $16.3 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $11.0 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.
- $4.3 million decrease in market-based demand fees, priority reservation fees and compression activity associated with lower throughput.
- $4.3 million net decrease due to decreased through-system volumes primarily associated with market conditions that resulted in reduced wellhead production and decreased drilling activity, partially offset by increased deliveries to our Mid-Tex Division.
- $2.8 million decrease due to the absence of excess inventory sales in the current-year period.

These decreases were partially offset by a $6.1 million increase associated with our GRIP filings.

Operating expenses decreased $3.5 million primarily due to a $7.0 million decrease related to lower levels of pipeline maintenance activities, partially offset by the following:

- $1.2 million increase due to higher employee-related expenses.
- $1.3 million increase due to higher ad valorem and payroll taxes.

Natural Gas Marketing Segment

Atmos Energy Marketing LLC's (AEM) primary business is to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. In addition, AEM utilizes proprietary and customer-owned transportation and storage assets to provide 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 financial instruments (delivered gas business). As a result, AEM's margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEM also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity we own or control in our natural gas distribution and natural gas marketing segments. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEM has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEM continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEM may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEM elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to hedge the original financial instruments. If AEM elects to defer the withdrawal of gas, it will reset its financial instruments by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEM also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory is hedged and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Due to the nature of these operations, natural gas prices have a significant impact on our natural gas marketing operations. Within our delivered gas business, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as

competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our natural gas marketing segment. Increased price volatility often has a significant impact on the spreads between market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Three Months Ended June 30, 2010 compared with Three Months Ended June 30, 2009

Financial and operational highlights for our natural gas marketing segment for the three months ended June 30, 2010 and 2009 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended June 30		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 12,550	$ 16,598	$ (4,048)
Asset optimization[1]	8,303	(14,580)	22,883
	20,853	2,018	18,835
Unrealized margins	(14,548)	13,004	(27,552)
Gross profit	6,305	15,022	(8,717)
Operating expenses	7,467	7,555	(88)
Operating income (loss)	(1,162)	7,467	(8,629)
Miscellaneous income	147	71	76
Interest charges	1,767	4,020	(2,253)
Income (loss) before income taxes	(2,782)	3,518	(6,300)
Income tax expense (benefit)	(683)	1,419	(2,102)
Net income (loss)	$ (2,099)	$ 2,099	$ (4,198)
Gross natural gas marketing sales volumes — MMcf	91,854	103,146	(11,292)
Consolidated natural gas marketing sales volumes — MMcf	75,014	84,162	(9,148)
Net physical position (Bcf)	18.4	20.0	(1.6)

[1] Net of storage fees of $2.7 million and $2.0 million.

AEM's delivered gas business contributed 60 percent to total realized margins during the third quarter of fiscal 2010, with its asset optimization activities contributing the remaining 40 percent. The $18.8 million increase in realized gross profit reflected:

- A $22.9 million increase in asset optimization margins. During the current quarter, spot-to-forward spread values were very narrow due to unfavorable natural gas price fundamentals. As a result, AEM elected to maintain short-term trading positions, and generated incremental realized gains from rolling these positions throughout the quarter. This is in contrast to the prior-year quarter where AEM realized losses on the settlement of financial instruments after it elected to defer storage withdrawals and reset the corresponding financial instruments to capture additional summer/winter spread values.
- A $4.0 million decrease in realized delivered gas margins due to lower per-unit margins as a result of narrowing basis spreads combined with decreased delivered gas volumes. Per-unit margins were $0.14/Mcf in the current-year quarter compared with $0.16/Mcf in the prior-year period, while delivered sales volumes were 11 percent lower in the current-year period when compared with the prior-year quarter.

The increase in realized gross profit was more than offset by a $27.6 million decrease in unrealized margins primarily due to the quarter-over-quarter timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes and asset impairments, decreased $0.1 million primarily due to a decrease in employee and other administrative costs.

Interest charges decreased $2.3 million primarily due to a decrease in intercompany borrowings.

Nine Months Ended June 30, 2010 compared with Nine Months Ended June 30, 2009

Financial and operational highlights for our natural gas marketing segment for the nine months ended June 30, 2010 and 2009 are presented below.

	Nine Months Ended June 30		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Delivered gas	$ 45,763	$ 58,316	$(12,553)
Asset optimization[(1)]	39,623	20,286	19,337
	85,386	78,602	6,784
Unrealized margins	(12,816)	(10,013)	(2,803)
Gross profit	72,570	68,589	3,981
Operating expenses	25,270	30,230	(4,960)
Operating income	47,300	38,359	8,941
Miscellaneous income	642	490	152
Interest charges	6,965	11,383	(4,418)
Income before income taxes	40,977	27,466	13,511
Income tax expense	16,506	11,444	5,062
Net income	$ 24,471	$ 16,022	$ 8,449
Gross natural gas marketing sales volumes — MMcf	317,992	336,870	(18,878)
Consolidated natural gas marketing sales volumes — MMcf	267,136	282,443	(15,307)
Net physical position (Bcf)	18.4	20.0	(1.6)

(1) Net of storage fees of $8.7 million and $7.5 million.

AEM's delivered gas business contributed 54 percent of total realized margins during the nine months ended June 30, 2010 with asset optimization activities contributing the remaining 46 percent. The $6.8 million increase in realized gross profit reflected the following:

- $19.3 million increase in asset optimization margins primarily associated with realized gains earned from AEM's trading strategy executed during the fiscal third quarter.
- $12.6 million decrease in realized delivered gas margins due to lower per-unit margins as a result of narrowing basis spreads, combined with lower delivered sales volumes. Per-unit margins were $0.14/Mcf in the current-year period compared with $0.17/Mcf in the prior-year period, while delivered sales volumes were five percent lower in the current-year period when compared with the prior-year period.

The increase in realized gross profit was partially offset by a $2.8 million decrease in unrealized margins due to the period-over-period timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes and asset impairments decreased $5.0 million primarily due to a decrease in employee and other administrative costs.

Interest charges decreased $4.4 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEM monitors the impact of its asset optimization efforts by estimating the gross profit, before associated storage fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement, is referred to as the potential gross profit.

We define potential gross profit as the change in AEM's gross profit from asset optimization activities in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injections/withdrawals and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEM's economic value and its potential gross profit (loss) at June 30, 2010 and 2009.

	June 30	
	2010	2009
	(In millions, unless otherwise noted)	
Economic value	$ (8.6)	$ 42.0
Associated unrealized (gains) losses	15.7	(16.7)
Subtotal	7.1	25.3
Related fees[(1)]	(12.8)	(15.3)
Potential gross profit (loss)	$ (5.7)	$ 10.0
Net physical position (Bcf)	18.4	20.0

(1) Related fees represent AEM's contractual costs to acquire the storage capacity utilized in its asset optimization operations. The fees primarily consist of demand fees and contractual obligations to sell gas below market index prices in exchange for the right to manage and optimize third party storage assets for the positions AEM has entered into as of June 30, 2010 and 2009.

During the nine months ended June 30, 2010, AEM's economic value decreased from $28.6 million, or $2.07/Mcf at September 30, 2009 to a negative economic value of $8.6 million, or $0.47/Mcf. This compares unfavorably to AEM's economic value at June 30, 2009 of $42.0 million, or $2.10/Mcf.

Early in the first quarter of fiscal 2010, AEM withdrew gas and realized previously captured spread values. As current cash prices declined during the first fiscal quarter, AEM injected gas and rolled positions into the second fiscal quarter to increase economic value. These positions were settled in the second fiscal quarter and the associated economic value was realized. However, during the year, weak market fundamentals have caused cash prices to remain low and have contracted spot-to-forward spread values, which has limited opportunities to capture economic value. Therefore, during the fiscal third quarter, AEM elected to forego capturing these narrower spread values and maintained a short-term trading position. We anticipate spot-to-forward spread values will expand in the near term and we expect to be able to roll positions and capture greater economic value than what we can capture currently. However, the short-dated nature of AEM's trading positions combined with current short-term forward prices that are lower than the cost of gas that was injected into storage in prior periods resulted in negative economic value as of June 30, 2010.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit or loss calculated as of June 30, 2010 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Pipeline, Storage and Other Segment

Our pipeline, storage and other segment consists primarily of the operations of Atmos Pipeline and Storage, LLC (APS). APS is engaged in nonregulated transmission, storage and natural gas-gathering services. Its primary asset is a proprietary 21 mile pipeline located in New Orleans, Louisiana that is primarily used to aggregate gas supply for our regulated natural gas distribution division in Louisiana, our natural gas marketing segment, and, on a more limited basis, for third parties. APS also owns or has an interest in underground storage fields in Kentucky and Louisiana that are used to reduce the need of our natural gas distribution divisions to contract for additional pipeline capacity to meet customer demand during peak periods.

APS also engages in asset optimization activities whereby it seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require APS to share with our regulated customers a portion of the profits earned from these arrangements. APS also seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls by engaging in natural gas storage transactions in which it seeks to find and profit from the pricing differences that occur over time.

Results for this segment are primarily impacted by seasonal weather patterns and, similar to our natural gas marketing segment, volatility in the natural gas markets. Additionally, this segment's results include an unrealized component as APS hedges its risk associated with its asset optimization activities.

Three Months Ended June 30, 2010 compared with Three Months Ended June 30, 2009

Financial and operational highlights for our pipeline, storage and other segment for the three months ended June 30, 2010 and 2009 are presented below.

	Three Months Ended June 30		
	2010	2009	Change
		(In thousands)	
Asset optimization	$2,114	$ 1,051	$ 1,063
Storage and transportation services	3,319	3,470	(151)
Other	231	737	(506)
Unrealized margins	(198)	(1,244)	1,046
Gross profit	5,466	4,014	1,452
Operating expenses	3,200	2,823	377
Operating income	2,266	1,191	1,075
Miscellaneous income	670	2,319	(1,649)
Interest charges	451	408	43
Income before income taxes	2,485	3,102	(617)
Income tax expense	1,103	1,250	(147)
Net income	$1,382	$ 1,852	$ (470)

Gross profit from our pipeline, storage and other segment increased $1.5 million primarily due a $1.0 million increase in margins earned from APS' asset optimization activities due to the quarter-over-quarter timing of realized gains earned from one of APS' asset management plans and storage optimization activities.

Operating expenses increased $0.4 million primarily due to increased operating costs associated with APS' gas gathering activities.

Miscellaneous income decreased $1.7 million primarily due to lower intercompany interest income earned by this segment.

Nine Months Ended June 30, 2010 compared with Nine Months Ended June 30, 2009

Financial and operational highlights for our pipeline, storage and other segment for the nine months ended June 30, 2010 and 2009 are presented below.

	Nine Months Ended June 30		
	2010	2009	Change
		(In thousands)	
Asset optimization	$ 9,603	$21,675	$(12,072)
Storage and transportation services	9,746	10,097	(351)
Other	1,375	2,076	(701)
Unrealized margins	2,413	(6,673)	9,086
Gross profit	23,137	27,175	(4,038)
Operating expenses	10,282	7,239	3,043
Operating income	12,855	19,936	(7,081)
Miscellaneous income	2,103	6,540	(4,437)
Interest charges	2,291	1,821	470
Income before income taxes	12,667	24,655	(11,988)
Income tax expense	5,102	10,595	(5,493)
Net income	$ 7,565	$14,060	$ (6,495)

Gross profit from our pipeline, storage and other segment decreased $4.0 million primarily due to the following:

- $5.5 million decrease from lower margins earned on storage optimization activities.
- $4.1 million decrease in basis gains earned from utilizing leased capacity.
- $2.6 million decrease from lower margins earned on asset management plans.
- $9.1 million increase in unrealized margins associated with our asset optimization activities.

Operating expenses increased $3.0 million primarily due to increased operating costs associated with APS' gas gathering activities and administrative costs.

Miscellaneous income decreased $4.4 million primarily due to lower intercompany interest income earned by this segment.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources, including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

Our $350 million unsecured 7.375% Senior Notes will mature in May 2011. We are currently evaluating alternatives to replace this facility and believe we will successfully replace this facility on reasonably economical terms.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2010.

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, investing and financing activities for the nine months ended June 30, 2010 and 2009 are presented below.

	Nine Months Ended June 30		
	2010	2009	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 594,564	$ 824,594	$(230,030)
Investing activities	(362,787)	(348,420)	(14,367)
Financing activities	(162,597)	(397,156)	234,559
Change in cash and cash equivalents	69,180	79,018	(9,838)
Cash and cash equivalents at beginning of period	111,203	46,717	64,486
Cash and cash equivalents at end of period	$ 180,383	$ 125,735	$ 54,648

Cash flows from operating activities

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

For the nine months ended June 30, 2010, we generated operating cash flow of $594.6 million from operating activities compared with $824.6 million for the nine months ended June 30, 2009, primarily due to the fluctuation in gas costs. Gas costs, which reached historically high levels during the 2008 injection season, declined sharply when the economy slipped into the recession and have remained relatively stable since that time. Operating cash flow for the fiscal 2010 period reflects the recovery of lower gas costs through purchased gas recovery mechanisms and sales. This is in contrast to the fiscal 2009 period, where operating cash flow was favorably influenced by the recovery of high gas costs during a period of falling prices.

Cash flows from investing activities

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

Capital expenditures for fiscal 2010 are expected to range from $525 million to $540 million. For the nine months ended June 30, 2010, capital expenditures were $362.3 million compared with $342.3 million for the nine months ended June 30, 2009. The $20.0 million increase in capital expenditures primarily reflects spending for the relocation of our information technology data center to a new facility and the construction of two service centers.

Cash flows from financing activities

For the nine months ended June 30, 2010, our financing activities used $162.6 million of cash compared with $397.2 million of cash used in the prior-year period, primarily due to lower cash outflows associated with repayment of our long-term and short-term debt instruments as follows:

- $407.2 million for long-term debt repayments. In the current-year period, $0.1 million of long-term debt was repaid, compared with $407.3 million in the prior-year period.
- $290.4 million for short-term debt repayments. In the current-year period, $76.0 million of short-term debt was repaid, compared with $366.4 million in the prior-year period. The reduction in net borrowings reflects the timing of the use of our line of credit to finance natural gas purchases and working capital.

The lower repayment activity was partially offset by:

- $445.6 million decrease in cash inflows due to the absence of proceeds from the issuance of long-term debt that occurred in the prior-year period.
- $11.4 million decrease in cash inflows due to a substantial decrease in the number of shares of common stock issued to provide shares for our Retirement Savings Plan due to a change to purchasing such shares on the open market.
- $3.0 million additional cash used due to an increase in dividends paid in the current year compared to the prior year.
- $1.9 million decrease in cash inflows due to the absence of the settlement of a Treasury lock agreement that occurred in the prior-year period.

The following table summarizes our share issuances for the nine months ended June 30, 2010 and 2009.

	Nine Months Ended June 30	
	2010	**2009**
Shares issued:		
Direct Stock Purchase Plan	103,529	319,732
Retirement Savings Plan and Trust	79,722	484,111
1998 Long-Term Incentive Plan	375,039	613,314
Outside Directors Stock-for-Fee Plan	2,689	2,294
Total shares issued	560,979	1,419,451

The year-over-year decrease in the number of shares issued primarily reflects the fact that we have started using shares purchased in the open market rather than issuing shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. In addition, we awarded fewer shares under our 1998 Long-Term Incentive Plan due to the Company achieving a lower level of performance relative to the target performance established under the Plan during fiscal 2009 compared to fiscal 2008. Further, a higher average stock price during the second and third quarters of fiscal 2010 compared to the second and third quarters of 2009 enabled us to issue fewer shares during the current year-to-date period.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. We will receive the balance of the shares at the conclusion of the repurchase program. The specific number of shares we will ultimately repurchase in

the transaction will be based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. The agreement is scheduled to end in March 2011, although the termination date may be accelerated. As a result of this transaction, our weighted-average shares outstanding will be reduced over the remaining three months of fiscal 2010. Beginning in our fourth fiscal quarter, the outstanding shares used to calculate our earnings per share will be reduced by the number of shares repurchased as they are delivered to us and the $100 million purchase price will be recorded as a reduction in shareholders' equity. Assuming a volume-weighted average share price equal to the June 30, 2010 closing share price of $27.04, we expect the repurchase transaction to add from $0.01 to $0.02 to fiscal 2010 earnings per diluted share.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.2 billion of working capital funding. As of June 30, 2010, the amount available to us under our credit facilities, net of outstanding letters of credit, was $951.3 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

On March 31, 2010, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $1.3 billion in common stock and/or debt securities available for issuance.

We had already received approvals from all requisite state regulatory commissions to issue a total of $1.3 billion in common stock and/or debt securities under the new shelf registration statement, including the carryforward of the $450 million of securities remaining available for issuance under our shelf registration statement filed with the SEC on March 23, 2009. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities.

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 regulated and nonregulated 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). In March 2010, Moody's upgraded our rating outlook from stable to positive and affirmed the credit rating on our senior long-term debt at Baa2 and on our commercial paper at P-2. Moody's stated that the key driver for the upgrade was successful rate case outcomes over the past year. In March 2010, S&P affirmed our senior long-term debt credit rating of BBB+ and our rating outlook as stable. In June 2010, Fitch reaffirmed our senior long-term debt rating of BBB+ and commercial paper ratings of F-2 and upgraded our rating outlook from stable to positive. Fitch cited our effective management of the regulatory process as well as our consistent financial and operational performance as the

primary reasons for the upgrade. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently 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, 2010. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2010, September 30, 2009 and June 30, 2009:

	June 30, 2010		September 30, 2009		June 30, 2009	
	(In thousands, except percentages)					
Short-term debt	$ —	—	$ 72,550	1.6%	$ —	—
Long-term debt	2,169,677	48.4%	2,169,531	49.1%	2,169,526	49.7%
Shareholders' equity	2,313,730	51.6%	2,176,761	49.3%	2,191,520	50.3%
Total	$4,483,407	100.0%	$4,418,842	100.0%	$4,361,046	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 48.4 percent at June 30, 2010, 50.7 percent at September 30, 2009 and 49.7 percent at June 30, 2009. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2010.

As we previously discussed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provides the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. If the option is exercised, we will retain a non-controlling equity position in Fort Necessity and will share in a percentage of the profits. In July

2010, we signed an extension to the option and acquisition agreement which gives the third party until March 2011 to exercise the option to develop the project.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. To date, we have replaced approximately 51,000 of these lines. We are committed to replacing the steel service lines on an accelerated schedule to ensure the safety and reliability of our distribution system, and as part of this commitment, we support the objectives of the rulemaking outlined by the Texas Railroad Commission (RRC) for steel service-line replacements statewide. The RRC is not scheduled to consider a formal rulemaking for this program until August 2010. Due to the preliminary status of the rulemaking process, we cannot accurately anticipate the impact this rule would have on the Company or the expected cost of the replacement program.

Risk Management Activities

We conduct risk management activities through our natural gas distribution, natural gas marketing and pipeline, storage and other segments. In our natural gas distribution segment, we use a combination of physical 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 and pipeline, storage and other segments, 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and nine months ended June 30, 2010 and 2009:

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
	(In thousands)			
Fair value of contracts at beginning of period	$(21,735)	$(21,863)	$(14,166)	$ (63,677)
Contracts realized/settled	(20)	(844)	(34,438)	(101,840)
Fair value of new contracts	182	(885)	(2,054)	(4,891)
Other changes in value	1,183	1,564	30,268	148,380
Fair value of contracts at end of period	$(20,390)	$(22,028)	$(20,390)	$ (22,028)

The fair value of our natural gas distribution segment's financial instruments at June 30, 2010 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2010				
	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	$(20,161)	$(229)	$—	$—	$(20,390)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(20,161)	$(229)	$—	$—	$(20,390)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the three and nine months ended June 30, 2010 and 2009:

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
	(In thousands)			
Fair value of contracts at beginning of period	$14,227	$(32,646)	$ 26,698	$ 16,542
Contracts realized/settled	(8,100)	42,535	(32,342)	29,260
Fair value of new contracts	—	—	—	—
Other changes in value	(8,337)	8,555	3,434	(27,358)
Fair value of contracts at end of period	(2,210)	18,444	(2,210)	18,444
Netting of cash collateral	18,017	20,614	18,017	20,614
Cash collateral and fair value of contracts at period end	$15,807	$ 39,058	$ 15,807	$ 39,058

The fair value of our natural gas marketing segment's financial instruments at June 30, 2010 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2010				
	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	$(3,254)	$1,984	$(940)	$—	$(2,210)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(3,254)	$1,984	$(940)	$—	$(2,210)

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2010 and 2009, our total net periodic pension and other benefits costs were $38.1 million and $36.2 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2010 costs were determined using a September 30, 2009 measurement date. As of September 30, 2009, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of September 30, 2008, the measurement date for our fiscal 2009 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2010 pension and benefit costs to 5.52 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is mitigated by the fact that fluctuations in asset values are "smoothed" for purposes of determining net periodic pension cost. Accordingly, asset gains and losses are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Accordingly, our fiscal 2010 pension and postretirement medical costs were materially the same as in fiscal 2009.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2010. Based upon this valuation, we will not be required to make a contribution to our pension plans during the current fiscal year. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $12 million to these plans during fiscal 2010.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the

determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage, natural gas marketing and pipeline, storage and other segments for the three and nine month periods ended June 30, 2010 and 2009.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
METERS IN SERVICE, end of period				
Residential	2,915,031	2,924,160	2,915,031	2,924,160
Commercial	271,745	274,739	271,745	274,739
Industrial	2,420	2,195	2,420	2,195
Public authority and other	10,439	9,231	10,439	9,231
Total meters	3,199,635	3,210,325	3,199,635	3,210,325
INVENTORY STORAGE BALANCE — Bcf	34.7	37.9	34.7	37.9
SALES VOLUMES — MMcf[(1)]				
Gas sales volumes				
Residential	17,436	19,043	178,840	147,718
Commercial	13,982	14,398	91,087	79,416
Industrial	3,544	3,921	15,523	15,079
Public authority and other	1,377	2,719	8,733	10,874
Total gas sales volumes	36,339	40,081	294,183	253,087
Transportation volumes	30,311	30,637	107,097	102,091
Total throughput	66,650	70,718	401,280	355,178
OPERATING REVENUES (000's)[(1)]				
Gas sales revenues				
Residential	$ 235,693	$ 224,629	$1,640,853	$1,657,185
Commercial	119,434	106,739	705,114	744,248
Industrial	19,470	21,028	92,280	117,442
Public authority and other	9,160	13,712	61,744	82,097
Total gas sales revenues	383,757	366,108	2,499,991	2,600,972
Transportation revenues	13,896	13,756	48,590	46,411
Other gas revenues	7,618	7,121	25,572	25,990
Total operating revenues	$ 405,271	$ 386,985	$2,574,153	$2,673,373
Average transportation revenue per Mcf	$ 0.46	$ 0.45	$ 0.45	$ 0.45
Average cost of gas per Mcf sold	$ 5.73	$ 4.87	$ 5.77	$ 7.18

See footnote following these tables.

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

	Three Months Ended June 30		Nine Months Ended June 30	
	2010	2009	2010	2009
CUSTOMERS, end of period				
Industrial	732	706	732	706
Municipal	61	63	61	63
Other	507	505	507	505
Total	1,300	1,274	1,300	1,274
INVENTORY STORAGE BALANCE — Bcf				
Natural gas marketing	20.2	23.3	20.2	23.3
Pipeline, storage and other	1.7	2.5	1.7	2.5
Total	21.9	25.8	21.9	25.8
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	127,861	169,641	478,075	555,169
NATURAL GAS MARKETING SALES VOLUMES — MMcf[(1)]	91,854	103,146	317,992	336,870
OPERATING REVENUES (000's)[(1)]				
Regulated transmission and storage	$ 44,957	$ 49,345	$ 146,998	$ 163,261
Natural gas marketing	421,406	453,504	1,657,829	1,949,657
Pipeline, storage and other	8,196	8,226	28,869	36,946
Total operating revenues	$474,559	$511,075	$1,833,696	$2,149,864

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. During the nine months ended June 30, 2010, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2010 to provide reasonable assurance that information

required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of the fiscal year ended September 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the nine months ended June 30, 2010, except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2009. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. ***Exhibits***

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

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President, Chief Financial Officer and Treasurer
(Duly authorized signatory)

Date: August 5, 2010

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
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*	
101.INS	XBRL Instance Document**	
101.SCH	XBRL Taxonomy Extension Schema**	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase**	
101.LAB	XBRL Taxonomy Extension Labels Linkbase**	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase**	

* 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.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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

Form 10-Q

(Mark One)

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

For the quarterly period ended December 31, 2010

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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 February 3, 2011.

Class	Shares Outstanding
No Par Value	90,648,911

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MPSC	Mississippi Public Service Commission
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2010	September 30, 2010
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,638,718	$6,542,318
Less accumulated depreciation and amortization	1,779,374	1,749,243
Net property, plant and equipment	4,859,344	4,793,075
Current assets		
Cash and cash equivalents	129,892	131,952
Accounts receivable, net	564,934	273,207
Gas stored underground	339,105	319,038
Other current assets	229,324	150,995
Total current assets	1,263,255	875,192
Goodwill and intangible assets	739,991	740,148
Deferred charges and other assets	359,033	355,376
	$7,221,623	$6,763,791
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2010 — 90,638,491 shares September 30, 2010 — 90,164,103 shares	$ 453	$ 451
Additional paid-in capital	1,724,899	1,714,364
Retained earnings	529,900	486,905
Accumulated other comprehensive income (loss)	19,601	(23,372)
Shareholders' equity	2,274,853	2,178,348
Long-term debt	1,807,319	1,809,551
Total capitalization	4,082,172	3,987,899
Current liabilities		
Accounts payable and accrued liabilities	510,085	266,208
Other current liabilities	349,914	413,640
Short-term debt	247,993	126,100
Current maturities of long-term debt	352,434	360,131
Total current liabilities	1,460,426	1,166,079
Deferred income taxes	892,090	829,128
Regulatory cost of removal obligation	354,871	350,521
Deferred credits and other liabilities	432,064	430,164
	$7,221,623	$6,763,791

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2010	2009
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 727,195	$ 802,894
Regulated transmission and storage segment	49,007	46,860
Nonregulated segment	475,640	548,016
Intersegment eliminations	(94,847)	(104,918)
	1,156,995	1,292,852
Purchased gas cost		
Natural gas distribution segment	427,423	508,267
Regulated transmission and storage segment	—	—
Nonregulated segment	450,462	478,241
Intersegment eliminations	(94,450)	(104,505)
	783,435	882,003
Gross profit	373,560	410,849
Operating expenses		
Operation and maintenance	116,594	123,862
Depreciation and amortization	56,161	53,839
Taxes, other than income	40,696	42,552
Total operating expenses	213,451	220,253
Operating income	160,109	190,596
Miscellaneous expense	(737)	(269)
Interest charges	38,917	38,708
Income before income taxes	120,455	151,619
Income tax expense	46,458	58,289
Net income	$ 73,997	$ 93,330
Basic net income per share	$ 0.81	$ 1.00
Diluted net income per share	$ 0.81	$ 1.00
Cash dividends per share	$ 0.340	$ 0.335
Weighted average shares outstanding:		
Basic	90,082	92,152
Diluted	90,408	92,509

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2010	2009
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 73,997	$ 93,330
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	56,161	53,839
Charged to other accounts	46	36
Deferred income taxes	43,423	12,832
Other	4,712	4,382
Net assets / liabilities from risk management activities	5,304	(26,891)
Net change in operating assets and liabilities	(137,819)	(42,372)
Net cash provided by operating activities	45,824	95,156
Cash Flows From Investing Activities		
Capital expenditures	(123,162)	(115,439)
Other, net	(370)	(1,873)
Net cash used in investing activities	(123,532)	(117,312)
Cash Flows From Financing Activities		
Net increase in short-term debt	112,628	111,335
Repayment of long-term debt	(10,000)	—
Cash dividends paid	(31,002)	(31,234)
Repurchase of equity awards	(3,231)	—
Issuance of common stock	7,253	5,681
Net cash provided by financing activities	75,648	85,782
Net increase (decrease) in cash and cash equivalents	(2,060)	63,626
Cash and cash equivalents at beginning of period	131,952	111,203
Cash and cash equivalents at end of period	$ 129,892	$ 174,829

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2010

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc, (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

As discussed in Note 10, we operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

2. Unaudited Interim Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2010 are not indicative of our results of operations for the full 2011 fiscal year, which ends September 30, 2011.

We have evaluated subsequent events from the December 31, 2010 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). Except as discussed

in Note 8, no events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the three months ended December 31, 2010, two new accounting standards became applicable to the Company pertaining to goodwill impairment testing for reporting units with zero or negative carrying amounts and disclosure of supplementary pro forma information for business combinations. The adoption of these standards did not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the quarter ended December 31, 2010.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities, and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of December 31, 2010 and September 30, 2010 included the following:

	December 31, 2010	September 30, 2010
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$206,165	$209,564
Merger and integration costs, net	6,596	6,714
Deferred gas costs	48,205	22,701
Regulatory cost of removal asset	38,533	31,014
Environmental costs	704	805
Rate case costs	4,756	4,505
Deferred franchise fees	452	1,161
Other	2,643	1,046
	$308,054	$277,510
Regulatory liabilities:		
Deferred gas costs	$ 8,424	$ 43,333
Deferred franchise fees	2,812	—
Regulatory cost of removal obligation	388,391	381,474
Other	6,012	6,112
	$405,639	$430,919

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 applicable state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2010 and 2009:

	Three Months Ended December 31	
	2010	2009
	(In thousands)	
Net income	$ 73,997	$ 93,330
Unrealized holding gains on investments, net of tax expense of $455 and $390 for the three months ended December 31, 2010 and 2009	776	664
Amortization and unrealized gain on interest rate hedging transactions, net of tax expense of $18,704 and $248 for the three months ended December 31, 2010 and 2009	31,847	422
Net unrealized gains on commodity hedging transactions, net of tax expense of $6,617 and $4,254 for the three months ended December 31, 2010 and 2009	10,350	6,654
Comprehensive income	$116,970	$101,070

Accumulated other comprehensive income (loss), net of tax, as of December 31, 2010 and September 30, 2010 consisted of the following unrealized gains (losses):

	December 31, 2010	September 30, 2010
	(In thousands)	
Accumulated other comprehensive income (loss):		
Unrealized holding gains on investments	$ 4,981	$ 4,205
Treasury lock agreements[1]	26,379	(5,468)
Cash flow hedges	(11,759)	(22,109)
	$ 19,601	$(23,372)

[1] The increase primarily reflects the change in fair value of certain Treasury lock agreements executed in September 2010. See Note 3 for further information.

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the first quarter there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit risk-related or other contingent features that could cause payments to be accelerated when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2010-2011 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 35 percent, or 31.5 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas costs adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver 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.

We also perform asset optimization activities in our nonregulated segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated segment is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a

fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 56 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on December 31, 2010, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.5 Bcf.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

We intend to refinance our $350 million unsecured 7.375% Senior Notes that will mature in May 2011 through the issuance of 30-year unsecured senior notes in June 2011. Additionally, we anticipate issuing $250 million of 30-year unsecured senior notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into five Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges of an anticipated transaction.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a cumulative net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts associated with the settled Treasury locks will be recognized by the end of fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of December 31, 2010, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2010, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(21,100)
	Cash Flow	—	35,177
	Not designated	17,171	38,571
		17,171	52,648

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of December 31, 2010 and September 30, 2010. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $25.3 million and $24.9 million of cash held on deposit as of December 31, 2010 and September 30, 2010 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
December 31, 2010:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 28,489	$ 28,489
Noncurrent commodity contracts	Deferred charges and other assets	—	384	384
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(38,419)	(38,419)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(7,841)	(7,841)
Total		—	(17,387)	(17,387)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	50,653	16,061	66,714
Noncurrent commodity contracts	Deferred charges and other assets	77	1,816	1,893
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(22,944)	(10,330)	(33,274)
Noncurrent commodity contracts	Deferred credits and other liabilities	(980)	(841)	(1,821)
Total		26,806	6,706	33,512
Total Financial Instruments		$ 26,806	$(10,681)	$ 16,125

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2010:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 40,030	$ 40,030
Noncurrent commodity contracts	Deferred charges and other assets	—	2,461	2,461
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(56,575)	(56,575)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(9,222)	(9,222)
Total		—	(23,306)	(23,306)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	2,219	16,459	18,678
Noncurrent commodity contracts	Deferred charges and other assets	47	2,056	2,103
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(48,942)	(7,178)	(56,120)
Noncurrent commodity contracts	Deferred credits and other liabilities	(2,924)	(405)	(3,329)
Total		(49,600)	10,932	(38,668)
Total Financial Instruments		$(49,600)	$(12,374)	$(61,974)

Impact of Financial Instruments on the Income Statement

The following tables present the impact that financial instruments had on our condensed consolidated income statement, by operating segment, as applicable, for the three months ended December 31, 2010 and 2009.

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended December 31, 2010 and 2009 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $13.5 million and $45.3 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three months ended December 31, 2010 and 2009 is presented below.

	Three Months Ended December 31	
	2010	2009
	(In thousands)	
Commodity contracts	$ (1,723)	$ (2,639)
Fair value adjustment for natural gas inventory designated as the hedged item	15,625	49,183
Total impact on revenue	$13,902	$46,544
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ 921	$ 64
Timing ineffectiveness	12,981	46,480
	$13,902	$46,544

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot to forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 2010 and 2009 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions are settled.

	Three Months Ended December 31, 2010		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(14,253)	$(14,253)
Loss arising from ineffective portion of commodity contracts	—	(444)	(444)
Total impact on revenue	—	(14,697)	(14,697)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(670)	—	(670)
Total Impact from Cash Flow Hedges	$(670)	$(14,697)	$(15,367)

	Three Months Ended December 31, 2009		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(23,117)	$(23,117)
Loss arising from ineffective portion of commodity contracts	—	(1,218)	(1,218)
Total impact on revenue	—	(24,335)	(24,335)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(670)	—	(670)
Total Impact from Cash Flow Hedges	$(670)	$(24,335)	$(25,005)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 2010 and 2009. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended December 31	
	2010	2009
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$31,425	$ —
Forward commodity contracts	1,657	(7,447)
Recognition of losses in earnings due to settlements:		
Treasury lock agreements	422	422
Forward commodity contracts	8,693	14,101
Total other comprehensive income from hedging, net of tax[(1)]	$42,197	$ 7,076

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Deferred losses recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 2010. However, the table below does not include the expected recognition in earnings of the Treasury lock agreements entered into on September 30, 2010 as those instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,687)	$ (7,286)	$ (8,973)
Thereafter	(3,702)	(4,473)	(8,175)
Total[(1)]	$(5,389)	$(11,759)	$(17,148)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended December 31, 2010 and 2009 was an increase in revenue of $4.2 million and $15.3 million. Note that this does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this is not indicative of the economic gross profit we realized when the underlying physical and financial transactions are settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded.

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the first quarter of fiscal 2011, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 8 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2010.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and September 30, 2010. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	December 31, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$50,730	$ —	$ —	$ 50,730
Nonregulated segment	10,006	36,745	—	(25,033)	21,718
Total financial instruments	10,006	87,475	—	(25,033)	72,448
Hedged portion of gas stored underground	84,734	—	—	—	84,734
Available-for-sale securities	42,617	—	—	—	42,617
Total assets	$137,357	$87,475	$ —	$(25,033)	$199,799
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$23,924	$ —	$ —	$ 23,924
Nonregulated segment	26,667	30,765	—	(50,329)	7,103
Total liabilities	$ 26,667	$54,689	$ —	$(50,329)	$ 31,027

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,266	$ —	$ —	$ 2,266
Nonregulated segment	18,544	42,462	—	(41,760)	19,246
Total financial instruments	18,544	44,728	—	(41,760)	21,512
Hedged portion of gas stored underground	57,507	—	—	—	57,507
Available-for-sale securities	41,466	—	—	—	41,466
Total assets	$117,517	$44,728	$ —	$(41,760)	$120,485
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,866	$ —	$ —	$ 51,866
Nonregulated segment	41,430	31,950	—	(66,649)	6,731
Total liabilities	$ 41,430	$83,816	$ —	$(66,649)	$ 58,597

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of December 31, 2010, we had $25.3 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $8.3 million was used to offset current risk management liabilities under master netting arrangements and the remaining $17.0 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of December 31, 2010:

	December 31, 2010
	(In thousands)
Carrying Amount	$2,162,696
Fair Value	$2,359,916

5. Debt

Long-term debt

Long-term debt at December 31, 2010 and September 30, 2010 consisted of the following:

	December 31, 2010	September 30, 2010
	(In thousands)	
Unsecured 7.375% Senior Notes, due May 2011	$ 350,000	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 2010	—	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term note due in installments through 2013	393	393
Total long-term debt	2,162,696	2,172,696
Less:		
Original issue discount on unsecured senior notes and debentures	(2,943)	(3,014)
Current maturities	(352,434)	(360,131)
	$1,807,319	$1,809,551

As noted above, our Unsecured 7.375% Senior Notes will mature in May 2011 and our Unsecured 10% Notes will mature in December 2011; accordingly, these have been classified within the current maturities of long-term debt.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.0 billion of working capital funding. At December 31, 2010 and September 30, 2010, there was $248.0 million and $126.1 million outstanding under our commercial paper program. As of December 31, 2010, our commercial paper had maturities of less than one week with an interest rate of 0.33 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $800 million of working capital funding. The first facility is a five-year $566.7 million unsecured facility, expiring December 15, 2011, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At December 31, 2010, there were no borrowings under this facility, but we had $248.0 million of commercial paper outstanding, leaving $318.7 million available.

The second facility is a $200 million unsecured 180-day facility that expires in April 2011. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.50 percent to 2.75 percent, based on the Company's credit ratings. At December 31, 2010, there were no borrowings outstanding under this facility.

The third facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At December 31, 2010, there were no borrowings outstanding under this facility.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2010, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $200 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility, (ii) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (iii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011 for up to $350 million. There was $117.6 million outstanding under this facility at December 31, 2010.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), a wholly-owned subsidiary of AEH maintains a third-party commercial revolving credit facility primarily to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. On December 8, 2010, AEM and the participating

banks amended and restated AEM's one-year $450 million committed revolving credit facility, replacing it with a $200 million three-year facility with an accordion feature that could increase AEM's borrowing capacity to $500 million.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At December 31, 2010, there were no borrowings outstanding under this credit facility. However, at December 31, 2010, AEM letters of credit totaling $37.8 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 $112.2 million at December 31, 2010.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At December 31, 2010, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.25 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at December 31, 2010, AEM's net working capital was $195.8 million and its tangible net worth was $207.0 million.

Finally, AEH had a $200 million intercompany demand credit facility with AEC, which bore interest at greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. In October 2010, we received regulatory approval to increase this facility, effective December 1, 2010 through December 31, 2011, to $350 million with substantially the same terms. There were no borrowings outstanding under this facility at December 31, 2010.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities. At December 31, 2010, no amounts have been drawn down against the shelf registration statement.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness

arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of December 31, 2010. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three months ended December 31, 2010 and 2009 are calculated as follows:

	Three Months Ended December 31	
	2010	2009
	(In thousands, except per share amounts)	
Basic Earnings Per Share		
Net income	$73,997	$93,330
Less: Income allocated to participating securities	779	1,037
Net income available to common shareholders	$73,218	$92,293
Basic weighted average shares outstanding	90,082	92,152
Net income per share — Basic	$ 0.81	$ 1.00
Diluted Earnings Per Share		
Net income available to common shareholders	$73,218	$92,293
Effect of dilutive stock options and other shares	2	3
Net income available to common shareholders	$73,220	$92,296
Basic weighted average shares outstanding	90,082	92,152
Additional dilutive stock options and other shares	326	357
Diluted weighted average shares outstanding	90,408	92,509
Net income per share — Diluted	$ 0.81	$ 1.00

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three months ended December 31, 2010 and 2009 as their exercise price was less than the average market price of the common stock during that period.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2010 and 2009 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the first quarter ended December 31, 2010, a limited number of participants elected to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. The curtailment gain will be recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,380	$ 3,993	$3,601	$3,360
Interest cost	6,924	6,524	3,203	3,018
Expected return on assets	(5,963)	(6,320)	(682)	(615)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(112)	(193)	(362)	(375)
Amortization of actuarial loss	3,494	2,822	87	93
Net periodic pension cost	$ 8,723	$ 6,826	$6,225	$5,859

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2010 and 2009 are as follows:

	Pension Benefits		Other Benefits	
	2010	2009	2010	2009
Discount rate	5.39%	5.52%	5.39%	5.52%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of

2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we expect we will be required to contribute less than $2 million to our pension plans by September 15, 2011.

We contributed $2.7 million to our other post-retirement benefit plans during the three months ended December 31, 2010. We expect to contribute a total of approximately $11 million to these plans during fiscal 2011.

For our Supplemental Executive Retirement Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of December 31, 2010:				
Domestic equity mutual funds	$28,686	$6,598	$ —	$35,284
Foreign equity mutual funds	4,426	1,308	—	5,734
Money market funds	1,599	—	—	1,599
	$34,711	$7,906	$ —	$42,617
As of September 30, 2010:				
Domestic equity mutual funds	$29,540	$5,698	$ —	$35,238
Foreign equity mutual funds	4,753	976	—	5,729
Money market funds	499	—	—	499
	$34,792	$6,674	$ —	$41,466

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 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2010. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC, have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing is scheduled on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. In the event the trial judge denies these motions, Atmos Energy will appeal the decision. We strongly believe that the trial court erred in not granting our motion to dismiss the lawsuit prior to trial and that the verdict is unsupported by law. After consultation with counsel, we believe that it is probable that any judgment based on this verdict would be overturned on appeal.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued does not reflect the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2010, AEH was committed to purchase 74.1 Bcf within one year, 36.2 Bcf within one to three years and 6.4 Bcf after three years under indexed contracts. AEH is committed to purchase 3.1 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $3.87 to $6.36 per Mcf. Purchases under these contracts totaled $334.2 million and $354.1 million for the three months ended December 31, 2010 and 2009.

Our natural gas distribution divisions, except for our 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 this service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of December 31, 2010 are as follows (in thousands):

2011	$178,340
2012	73,729
2013	5,353
2014	2,311
2015	—
Thereafter	—
	$259,733

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. There were no material changes to the estimated storage and transportation fees for the quarter ended December 31, 2010.

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. There have been no material developments in this matter during the quarter ended December 31, 2010. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities our Mid-Tex Division serves have agreed to a program of installing 100,000 replacements during the next two years, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing 8,079 lines for a cost of $10.0 million. The program is progressing on schedule for completion in September 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

As of December 31, 2010, rate cases were in progress in our Atmos Pipeline — Texas and West Texas service areas and annual rate filing mechanisms were in progress in our Louisiana and Mississippi service

areas. In addition, there were other ratemaking activities in progress in our Kansas and Missouri service areas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the three months ended December 31, 2010, there were no material changes in our concentration of credit risk.

10. Segment Information

Through November 30, 2010, our operations were divided into four segments:

- The *natural gas distribution segment*, which included our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which included the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which included a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which included our nonregulated natural gas gathering transmission and storage services.

As a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- The *natural gas distribution segment*, remains unchanged and includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, remains unchanged and includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services which were previously reported in the natural gas marketing and pipeline, storage and other segments.

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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2010. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three month periods ended December 31, 2010 and 2009 by segment are presented in the following tables to reflect our business structure as of December 31, 2010. Prior-year amounts have been restated accordingly.

	Three Months Ended December 31, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$726,994	$21,233	$408,768	$ —	$1,156,995
Intersegment revenues	201	27,774	66,872	(94,847)	—
	727,195	49,007	475,640	(94,847)	1,156,995
Purchased gas cost	427,423	—	450,462	(94,450)	783,435
Gross profit	299,772	49,007	25,178	(397)	373,560
Operating expenses					
Operation and maintenance	91,333	15,574	10,084	(397)	116,594
Depreciation and amortization	49,278	5,799	1,084	—	56,161
Taxes, other than income	34,976	3,553	2,167	—	40,696
Total operating expenses	175,587	24,926	13,335	(397)	213,451
Operating income	124,185	24,081	11,843	—	160,109
Miscellaneous income (expense)	(709)	(282)	290	(36)	(737)
Interest charges	29,719	8,064	1,170	(36)	38,917
Income before income taxes	93,757	15,735	10,963	—	120,455
Income tax expense	36,439	5,633	4,386	—	46,458
Net income	$ 57,318	$10,102	$ 6,577	$ —	$ 73,997
Capital expenditures	$109,499	$12,739	$ 924	$ —	$ 123,162

	Three Months Ended December 31, 2009				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$802,686	$19,842	$470,324	$ —	$1,292,852
Intersegment revenues	208	27,018	77,692	(104,918)	—
	802,894	46,860	548,016	(104,918)	1,292,852
Purchased gas cost	508,267	—	478,241	(104,505)	882,003
Gross profit	294,627	46,860	69,775	(413)	410,849
Operating expenses					
Operation and maintenance	96,033	17,579	10,663	(413)	123,862
Depreciation and amortization	47,857	4,942	1,040	—	53,839
Taxes, other than income	37,990	3,267	1,295	—	42,552
Total operating expenses	181,880	25,788	12,998	(413)	220,253
Operating income	112,747	21,072	56,777	—	190,596
Miscellaneous income (expense)	657	43	376	(1,345)	(269)
Interest charges	29,678	7,968	2,407	(1,345)	38,708
Income before income taxes	83,726	13,147	54,746	—	151,619
Income tax expense	32,278	4,693	21,318	—	58,289
Net income	$ 51,448	$ 8,454	$ 33,428	$ —	$ 93,330
Capital expenditures	$100,462	$13,759	$ 1,218	$ —	$ 115,439

Balance sheet information at December 31, 2010 and September 30, 2010 by segment is presented to reflect our business structure as of December 31, 2010 in the following tables. Prior-year amounts have been restated accordingly.

	December 31, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,020,501	$753,679	$ 85,164	$ —	$4,859,344
Investment in subsidiaries	647,892	—	(2,096)	(645,796)	—
Current assets					
Cash and cash equivalents	36,144	—	93,748	—	129,892
Assets from risk management activities	50,653	—	21,718	—	72,371
Other current assets	774,001	11,908	418,599	(143,516)	1,060,992
Intercompany receivables	520,489	—	—	(520,489)	—
Total current assets	1,381,287	11,908	534,065	(664,005)	1,263,255
Intangible assets	—	—	677	—	677
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	77	—	—	—	77
Deferred charges and other assets	334,654	8,210	16,092	—	358,956
	$6,956,673	$906,138	$668,613	$(1,309,801)	$7,221,623
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,274,853	$222,788	$425,104	$ (647,892)	$2,274,853
Long-term debt	1,807,057	—	262	—	1,807,319
Total capitalization	4,081,910	222,788	425,366	(647,892)	4,082,172
Current liabilities					
Current maturities of long-term debt	352,303	—	131	—	352,434
Short-term debt	365,614	—	—	(117,621)	247,993
Liabilities from risk management activities	22,944	—	621	—	23,565
Other current liabilities	618,402	12,779	229,052	(23,799)	836,434
Intercompany payables	—	516,442	4,047	(520,489)	—
Total current liabilities	1,359,263	529,221	233,851	(661,909)	1,460,426
Deferred income taxes	740,068	149,100	2,922	—	892,090
Noncurrent liabilities from risk management activities	980	—	6,482	—	7,462
Regulatory cost of removal obligation	354,871	—	—	—	354,871
Deferred credits and other liabilities	419,581	5,029	(8)	—	424,602
	$6,956,673	$906,138	$668,613	$(1,309,801)	$7,221,623

	September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$3,959,112	$748,947	$ 85,016	$ —	$4,793,075
Investment in subsidiaries	620,863	—	(2,096)	(618,767)	—
Current assets					
Cash and cash equivalents	31,952	—	100,000	—	131,952
Assets from risk management activities	2,219	—	18,356	—	20,575
Other current assets	528,655	19,504	325,348	(150,842)	722,665
Intercompany receivables	546,313	—	—	(546,313)	—
Total current assets	1,109,139	19,504	443,704	(697,155)	875,192
Intangible assets	—	—	834	—	834
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	47	—	890	—	937
Deferred charges and other assets	324,707	13,037	16,695	—	354,439
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,178,348	$212,687	$408,176	$ (620,863)	$2,178,348
Long-term debt	1,809,289	—	262	—	1,809,551
Total capitalization	3,987,637	212,687	408,438	(620,863)	3,987,899
Current liabilities					
Current maturities of long-term debt	360,000	—	131	—	360,131
Short-term debt	258,488	—	—	(132,388)	126,100
Liabilities from risk management activities	48,942	—	731	—	49,673
Other current liabilities	473,076	10,949	162,508	(16,358)	630,175
Intercompany payables	—	543,007	3,306	(546,313)	—
Total current liabilities	1,140,506	553,956	166,676	(695,059)	1,166,079
Deferred income taxes	691,126	142,337	(4,335)	—	829,128
Noncurrent liabilities from risk management activities	2,924	—	6,000	—	8,924
Regulatory cost of removal obligation	350,521	—	—	—	350,521
Deferred credits and other liabilities	413,416	4,849	2,975	—	421,240
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of December 31, 2010, the related condensed consolidated statements of income for the three-month periods ended December 31, 2010 and 2009, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2010 and 2009. 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, 2010, 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 12, 2010, 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, 2010, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
February 9, 2011

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, 2010.

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

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

OVERVIEW

Atmos Energy and its subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.

Through our nonregulated businesses, we provide natural gas management and transportation services to municipalities, natural gas distribution companies including certain of our natural gas distribution divisions and third parties primarily in the Midwest and Southeast. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 10, as a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

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, the 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 fiscal year ended September 30, 2010 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the three months ended December 31, 2010.

RESULTS OF OPERATIONS

We reported net income of $74.0 million, or $0.81 per diluted share for the three months ended December 31, 2010 compared with net income of $93.3 million, or $1.00 per diluted share in the prior-year quarter. Regulated operations contributed 91 percent of our net income during this period with our nonregulated operations contributing the remaining nine percent. Excluding the impact of unrealized margins, diluted earnings per share increased $0.10 compared with the prior-year quarter. The $0.10 per diluted share improvement reflects increased gross profit in our regulated operations from ratemaking activities, a 4 percent increase in regulated transmission and storage volumes and an 8 percent increase in nonregulated delivered gas volumes. These increases were partially offset by a 10 percent decline in natural gas distribution volumes and the continued adverse impact of low natural gas price volatility, which contributed to a decline in nonregulated per-unit delivered gas margins and realized asset optimization margins.

During the quarter, we executed on our strategy to streamline our credit facilities. In October 2010, we replaced our $200 million 364-day revolving credit agreement prior to its expiration with a $200 million 180-day revolving credit agreement. Additionally, in December 2010, we replaced Atmos Energy Marketing's (AEM) $450 million 364-day revolving credit facility with a $200 million three-year facility with an accordion feature that could increase AEM's borrowing capacity to $500 million. The new credit facilities should continue to help ensure we have sufficient liquidity to fund our working capital needs while reducing our financing costs.

The following table presents our consolidated financial highlights for the three months ended December 31, 2010 and 2009:

	Three Months Ended December 31	
	2010	2009
	(In thousands, except per share data)	
Operating revenues	$1,156,995	$1,292,852
Gross profit	373,560	410,849
Operating expenses	213,451	220,253
Operating income	160,109	190,596
Miscellaneous expense	(737)	(269)
Interest charges	38,917	38,708
Income before income taxes	120,455	151,619
Income tax expense	46,458	58,289
Net income	$ 73,997	$ 93,330
Diluted net income per share	$ 0.81	$ 1.00

Our consolidated net income during the three months ended December 31, 2010 and 2009 was earned in each of our business segments as follows:

	Three Months Ended December 31		
	2010	2009	Change
	(In thousands)		
Natural gas distribution segment	$57,318	$51,448	$ 5,870
Regulated transmission and storage segment	10,102	8,454	1,648
Nonregulated segment	6,577	33,428	(26,851)
Net income	$73,997	$93,330	$(19,333)

The following table reflects our consolidated net income and diluted earnings per share in our regulated and nonregulated operations:

	Three Months Ended December 31		
	2010	2009	Change
	(In thousands, except per share data)		
Regulated operations	$67,420	$59,902	$ 7,518
Nonregulated operations	6,577	33,428	(26,851)
Consolidated net income	$73,997	$93,330	$(19,333)
Diluted EPS from regulated operations	$ 0.74	$ 0.64	$ 0.10
Diluted EPS from nonregulated operations	0.07	0.36	(0.29)
Consolidated diluted EPS	$ 0.81	$ 1.00	$ (0.19)

Three Months Ended December 31, 2010 compared with Three Months Ended December 31, 2009

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
Virginia	January — December

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2010 and 2009 are presented below.

	Three Months Ended December 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Gross profit	$299,772	$294,627	$ 5,145
Operating expenses	175,587	181,880	(6,293)
Operating income	124,185	112,747	11,438
Miscellaneous income (expense)	(709)	657	(1,366)
Interest charges	29,719	29,678	41
Income before income taxes	93,757	83,726	10,031
Income tax expense	36,439	32,278	4,161
Net income	$ 57,318	$ 51,448	$ 5,870
Consolidated natural gas distribution sales volumes — MMcf	86,790	99,314	(12,524)
Consolidated natural gas distribution transportation volumes — MMcf	33,754	35,207	(1,453)
Total consolidated natural gas distribution throughput — MMcf	120,544	134,521	(13,977)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.49	$ 0.46	$ 0.03
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.92	$ 5.12	$ (0.20)

The following table shows our operating income by natural gas distribution division, in order of total rate base, for the three months ended December 31, 2010 and 2009. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31		
	2010	2009	Change
	(In thousands)		
Mid-Tex	$ 57,439	$ 50,381	$ 7,058
Kentucky/Mid-States	21,363	17,803	3,560
Louisiana	14,961	13,407	1,554
West Texas	9,520	11,757	(2,237)
Colorado-Kansas	8,012	8,606	(594)
Mississippi	10,215	9,802	413
Other	2,675	991	1,684
Total	$124,185	$112,747	$11,438

The $5.1 million increase in natural gas distribution gross profit primarily reflects a $14.1 million increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Missouri, Kentucky and Kansas service areas.

These increases were partially offset by:

- $4.9 million decrease due to a ten percent decrease in consolidated throughput caused principally by warmer weather this fiscal quarter compared to the same period last year in most of our service areas.
- $2.7 million decrease in revenue taxes, offset by revenue-related franchise taxes, as discussed below.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $6.3 million, primarily due to the following:

- $2.9 million decrease in franchise taxes.
- $2.6 million decrease in employee-related expenses.
- $1.4 million decrease in legal and other administrative costs.

Miscellaneous income decreased $1.4 million primarily due to a decrease in interest income.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the three months ended December 31, 2010 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $24.2 million resulting from ratemaking activity became effective in the quarter ended December 31, 2010 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Annual rate filing mechanisms	$23,122
Other rate activity	1,113
	$24,235

Additionally, the following ratemaking efforts were in progress during the first quarter of fiscal 2011 but had not been completed as of December 31, 2010.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Atmos Pipeline - Texas	Rate Case	Texas Railroad Commission	$35,282
Colorado-Kansas	Ad Valorem True Up[1]	Kansas	685
Kentucky/Mid-States	ISRS[2]	Missouri	382
Louisiana	Annual Rate Filing	TransLa	431
Mississippi	Annual Rate Filing	Mississippi	—
West Texas	Environs Rate Case	Amarillo	78
			$36,858

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in the Company's base rates.

(2) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. There were no fiscal 2011 rate cases completed as of December 31, 2010.

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the quarter ended December 31, 2010.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2009	$23,122	10/1/2010
Total 2011 Filings			$23,122	

The following table summarizes other ratemaking activity during the quarter ended December 31, 2010:

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2011 Other Rate Activity:				
Colorado-Kansas	Colorado	AMI[1]	$ 349	12/1/2010
Kentucky/Mid-States	Georgia	PRP Surcharge[2]	764	10/1/2010
Total 2011 Other Rate Activity			$1,113	

(1) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of the Company's service area.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2010 and 2009 are presented below.

	Three Months Ended December 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 27,535	$ 26,711	$ 824
Third-party transportation	16,512	15,242	1,270
Storage and park and lend services	2,170	2,605	(435)
Other	2,790	2,302	488
Gross profit	49,007	46,860	2,147
Operating expenses	24,926	25,788	(862)
Operating income	24,081	21,072	3,009
Miscellaneous income (expense)	(282)	43	(325)
Interest charges	8,064	7,968	96
Income before income taxes	15,735	13,147	2,588
Income tax expense	5,633	4,693	940
Net income	$ 10,102	$ 8,454	$ 1,648
Gross pipeline transportation volumes — MMcf	153,178	157,773	(4,595)
Consolidated pipeline transportation volumes — MMcf	99,841	95,938	3,903

The $2.1 million increase in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $3.1 million increase associated with our GRIP filings.
- $1.6 million increase in fixed fee services.

These increases were partially offset by the following:

- $1.5 million decrease resulting from lower per-unit transportation margins.
- $1.0 million decrease due to a decline in throughput to our Mid-Tex Division and a reduction in production.

Operating expenses decreased $0.9 million primarily due to lower levels of pipeline maintenance activities.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas 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 financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our

customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEH continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEH may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEH elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to hedge the original financial instruments. If AEH elects to defer the withdrawal of gas, it will reset its positions by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEH also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However,

increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the three months ended December 31, 2010 and 2009 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended December 31		
	2010	2009	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 16,041	$ 16,087	$ (46)
Storage and transportation services	3,349	3,334	15
Other	1,319	464	855
	20,709	19,885	824
Asset optimization	3,965	6,006	(2,041)
Total realized margins	24,674	25,891	(1,217)
Unrealized margins	504	43,884	(43,380)
Gross profit	25,178	69,775	(44,597)
Operating expenses	13,335	12,998	337
Operating income	11,843	56,777	(44,934)
Miscellaneous income	290	376	(86)
Interest charges	1,170	2,407	(1,237)
Income before income taxes	10,963	54,746	(43,783)
Income tax expense	4,386	21,318	(16,932)
Net income	$ 6,577	$ 33,428	$(26,851)
Gross nonregulated delivered gas sales volumes — MMcf	107,712	102,261	5,451
Consolidated nonregulated delivered gas sales volumes — MMcf	94,538	87,229	7,309
Net physical position (Bcf)	19.6	19.0	0.6

Realized margins for gas delivery, storage and transportation services and other services were $20.7 million, or 84 percent of total realized margins during the three months ended December 31, 2010 compared with $19.9 million, or 77 percent of total realized margins for the prior-year quarter. The increase reflects the following:

- An eight percent increase in consolidated sales volumes.
- A decrease in gas delivery per-unit margins from $0.16/Mcf in the prior-year quarter to $0.15/Mcf in the current-year quarter.
- The $0.9 million increase in other margins primarily reflects increased margin on sales of gas held in storage in the current-year quarter compared to the prior-year quarter.

The $2.0 million decrease in realized asset optimization margins from the prior-year quarter primarily reflects the impact of continued low natural gas market volatility. In the prior-year quarter, we were able to take advantage of more favorable trading opportunities in the daily cash market. These opportunities were not as readily available in the current quarter. Additionally, we realized lower spread values on the positions that were closed during the quarter compared with the prior-year quarter due to the decline in the physical to forward spread values experienced in the last 12-15 months.

The $43.4 million decrease in unrealized margins is due primarily to a significant unrealized gain recognized in the prior-year quarter. The prior-year quarter unrealized gain resulted from narrowing spreads between the then current cash prices and forward natural gas prices experienced on AEH's net physical position and the deferral of physical storage withdrawals to later in the 2010 fiscal year.

Interest charges decreased $1.2 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEH monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEH's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEH's economic value and its potential gross profit (loss) at December 31, 2010 and 2009.

	December 31	
	2010	2009
	(In millions, unless otherwise noted)	
Economic value	$ (2.6)	$ 25.7
Associated unrealized (gains) losses	10.2	(27.2)
Subtotal	7.6	(1.5)
Related fees[(1)]	(7.9)	(13.3)
Potential gross profit (loss)	$ (0.3)	$(14.8)
Net physical position (Bcf)	19.6	19.0

(1) Related fees represent the contractual costs to acquire the storage capacity utilized in our nonregulated segment's asset optimization activities. The fees primarily consist of demand fees and contractual obligations to sell gas below market index prices in exchange for the right to manage and optimize third party storage assets for the positions we have entered into as of December 31, 2010 and 2009.

During the quarter ended December 31, 2010, our nonregulated segment's economic value increased from ($7.5) million, or ($0.48)/Mcf at September 30, 2010 to ($2.6) million, or ($0.13)/Mcf. This compares unfavorably to economic value at December 31, 2009 of $25.7 million, or $1.35/Mcf.

During the three months ended December 31, 2010, the increase in our economic value reflected an increase in spread value resulting from (i) entering into financial hedges with higher average prices and (ii) reducing the weighted average cost of gas held in storage by withdrawing higher cost gas and injecting gas into storage at lower prices. We anticipate the majority of the economic value and corresponding reversal of unrealized mark-to-market gains will occur in fiscal 2011.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEH actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit calculated as of December 31, 2010 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. During fiscal 2011, we anticipate consolidating our short-term facilities used for our regulated operations into a single line of credit. In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that we do not plan to extend or replace upon expiration. In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility.

Our five-year $566.7 million facility will expire in December 2011. We expect to begin discussions during fiscal 2011 to replace the expiring five-year $566.7 million facility with a larger multi-year credit facility. We believe our existing five-year facility will provide adequate short-term borrowing capacity until we can successfully execute a new multi-year credit facility.

Our $350 million unsecured 7.375% Senior Notes will mature in May 2011. We intend to refinance this debt on a long-term basis through the issuance of 30-year unsecured senior notes in June 2011. Additionally, we plan to issue $250 million of 30-year unsecured senior notes in November 2011 to fund our capital expenditure program. On September 30, 2010, we entered into five Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. We designated all of the Treasury lock agreements as cash flow hedges of an anticipated transaction. Any realized gain or loss incurred when these agreements are settled will be recognized as a component of interest expense over the life of the related long-term debt.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2011.

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, investing and financing activities for the three months ended December 31, 2010 and 2009 are presented below.

	Three Months Ended December 31		
	2010	2009	2010 vs. 2009
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 45,824	$ 95,156	$(49,332)
Investing activities	(123,532)	(117,312)	(6,220)
Financing activities	75,648	85,782	(10,134)
Change in cash and cash equivalents	(2,060)	63,626	(65,686)
Cash and cash equivalents at beginning of period	131,952	111,203	20,749
Cash and cash equivalents at end of period	$ 129,892	$ 174,829	$(44,937)

Cash flows from operating activities

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

The $49.3 million decrease in operating cash flows primarily reflects the timing of customer collections and vendor payments.

Cash flows from investing activities

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

Capital expenditures for fiscal 2011 are expected to range from $580 million to $595 million. For the three months ended December 31, 2010, capital expenditures were $123.2 million compared with $115.4 million for the three months ended December 31, 2009. The $7.8 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and the purchase of software for new customer service systems in the current quarter partially offset by the relocation of the company's information technology data center in the prior-year quarter.

Cash flows from financing activities

The $10.1 million decrease in financing cash flows was primarily due to the following:

- $10.0 million additional cash used to repay long-term debt that matured in December 2010, partially offset by
- $1.3 million additional cash provided from short-term debt borrowings.

The following table summarizes our share issuances for the three months ended December 31, 2010 and 2009.

	Three Months Ended December 31	
	2010	2009
Shares issued:		
Direct Stock Purchase Plan	—	79,087
Retirement Savings Plan and Trust	—	79,722
1998 Long-Term Incentive Plan	595,103	259,550
Outside Directors Stock-for-Fee Plan	638	770
Total shares issued	595,741	419,129

The quarter-over-quarter change in the number of shares issued primarily reflects the fact that we are using shares purchased in the open market rather than issuing shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During the current quarter, we repurchased 121,353 shares attributable to equity awards which are not included in the table above.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. The specific number of shares we will ultimately repurchase in the transaction will be based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. The agreement is scheduled to end in the second fiscal quarter of 2011. As a result of this transaction, beginning in our fourth fiscal quarter of 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity. The number of shares used to calculate our earnings per share in fiscal 2011 will continue to be reduced by the shares we received in July 2010; however, the total impact to diluted earnings per share for fiscal 2011 will be dependent upon the average share price of our common stock over the remainder of the agreement.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.0 billion of working capital funding. As of December 31, 2010, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $656 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

In October 2010, our $200 million 364-day facility expired. We replaced the $200 million 364-day facility before its expiration with a $200 million 180-day credit facility that will expire in April 2011.

On December 8, 2010, the Company replaced AEM's existing $450 million 364-day committed revolving credit facility with a $200 million three-year facility with an accordion feature that could increase the Company's borrowing capacity to $500 million on substantially the same terms, except for a slight reduction in the rate of interest charged for both base rate and offshore borrowings and an extension of the facility for an additional three-year period. As a result of consolidating and reducing the amounts available under our facilities, we expect to reduce our short-term financing costs.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities. At December 31, 2010, no amounts have been drawn down on the shelf registration statement.

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 regulated and nonregulated 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). As of December 31, 2010, S&P maintained a stable outlook, while Moody's and Fitch maintained their ratings outlooks as positive. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of adverse global financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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 independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2010. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2010, September 30, 2010 and December 31, 2009:

	December 31, 2010		September 30, 2010		December 31, 2009	
	(In thousands, except percentages)					
Short-term debt	$ 247,993	5.3%	$ 126,100	2.8%	$ 179,712	3.9%
Long-term debt	2,159,753	46.1%	2,169,682	48.5%	2,169,601	47.1%
Shareholders' equity	2,274,853	48.6%	2,178,348	48.7%	2,258,076	49.0%
Total	$4,682,599	100.0%	$4,474,130	100.0%	$4,607,389	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.4 percent at December 31, 2010, 51.3 percent at September 30, 2010 and 51.0 percent at December 31, 2009. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2010.

As we previously discussed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we signed an extension to the option and acquisition agreement which gave the third party until March 2011 to exercise the option to develop the project. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011, accordingly, the option was terminated. We are currently evaluating our strategic alternatives with respect to this project.

Risk Management Activities

We conduct risk management activities through our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases.

In our nonregulated 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three months ended December 31, 2010 and 2009:

	Three Months Ended December 31	
	2010	2009
	(In thousands)	
Fair value of contracts at beginning of period	$ (49,600)	$(14,166)
Contracts realized/settled	(32,981)	(21,029)
Fair value of new contracts	531	(947)
Other changes in value	108,856	18,672
Fair value of contracts at end of period	$ 26,806	$(17,470)

The fair value of our natural gas distribution segment's financial instruments at December 31, 2010 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2010				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$27,709	$(903)	$—	$—	$26,806
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$27,709	$(903)	$—	$—	$26,806

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three months ended December 31, 2010 and 2009:

	Three Months Ended December 31	
	2010	2009
	(In thousands)	
Fair value of contracts at beginning of period	$(12,374)	$26,698
Contracts realized/settled	934	(2,212)
Fair value of new contracts	—	—
Other changes in value	759	7,820
Fair value of contracts at end of period	(10,681)	32,306
Netting of cash collateral	25,296	(1,315)
Cash collateral and fair value of contracts at period end	$ 14,615	$30,991

The fair value of our nonregulated segment's financial instruments at December 31, 2010 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2010				
	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	$(4,199)	$(6,467)	$(15)	$—	$(10,681)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(4,199)	$(6,467)	$(15)	$—	$(10,681)

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2010 and 2009, our total net periodic pension and other benefits cost was $14.9 million and $12.7 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2011 costs were determined using a September 30, 2010 measurement date. As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. We maintained the expected return on our pension plan assets at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Accordingly, our fiscal 2011 pension and postretirement medical costs for the quarter ended December 31, 2010 were significantly higher than the prior-year quarter.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the first quarter ended December 31, 2010, a limited number of participants elected to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. The curtailment gain will be recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we expect we will be required to contribute less than $2 million to our pension plans by September 15, 2011. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $11 million to these plans during fiscal 2011.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the three months ended December 31, 2010, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2010 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the three months ended December 31, 2010, except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. ***Exhibits***

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

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President, Chief Financial Officer and Treasurer
(Duly authorized signatory)

Date: February 9, 2011

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.1	Revolving Credit Agreement (180 Day Facility), dated as of October 15, 2010, among Atmos Energy Corporation, the Lenders from time to time parties thereto, SunTrust Bank as Administrative Agent, Wells Fargo Bank, N.A. as Syndication Agent, and Bank of America, N.A. and U.S. Bank National Association as Co-Documentation Agents	Exhibit 10.1 to Form 8-K dated October 15, 2010 (File No. 1-10042)
10.2	Fifth Amended and Restated Credit Agreement, dated as of December 8, 2010 among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank, a swing line bank and a bank; Société Générale as co-syndication agent, an issuing bank and a bank and the Royal Bank of Scotland, plc, as co-syndication agent and a bank; and Natixis, New York Branch, Credit Agricole Corporate and Investment Bank, and Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A. as co-documentation agents and the other financial institutions that become parties thereto	Exhibit 10.1 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.3	Third Amended and Restated Intercreditor Agreement, dated as of December 8, 2010 (as amended, supplemented and otherwise modified from time to time, the "Agreement"), among BNP Paribas, a bank organized under the laws of France, in its capacity as Collateral Agent (together with its successors and assigns in such capacity, the "Agent") for the Banks thereinafter referred to, and each bank and other financial institution which is now or hereafter a party to the Agreement in its capacity as a Bank and, as applicable, as a Swap Bank (collectively, the "Swap Banks") and/or a Physical Trade Bank (collectively, the "Physical Trade Banks")	Exhibit 10.2 to Form 8-K dated December 8, 2010 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	
101.INS	XBRL Instance Document**	
101.SCH	XBRL Taxonomy Extension Schema**	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase**	
101.LAB	XBRL Taxonomy Extension Labels Linkbase**	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase**	

* 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.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2011

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

Number of shares outstanding of each of the issuer's classes of common stock, as of April 29, 2011.

Class	Shares Outstanding
No Par Value	90,329,899

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
ISRS	Infrastructure System Replacement Surcharge
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2011	September 30, 2010
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,693,971	$6,542,318
Less accumulated depreciation and amortization	1,779,321	1,749,243
Net property, plant and equipment	4,914,650	4,793,075
Current assets		
Cash and cash equivalents	153,246	131,952
Accounts receivable, net	458,813	273,207
Gas stored underground	228,051	319,038
Other current assets	143,978	150,995
Total current assets	984,088	875,192
Goodwill and intangible assets	739,834	740,148
Deferred charges and other assets	357,252	355,376
	$6,995,824	$6,763,791
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2011 — 90,329,237 shares; September 30, 2010 — 90,164,103 shares	$ 452	$ 451
Additional paid-in capital	1,728,474	1,714,364
Retained earnings	631,044	486,905
Accumulated other comprehensive income (loss)	14,009	(23,372)
Shareholders' equity	2,373,979	2,178,348
Long-term debt	1,807,323	1,809,551
Total capitalization	4,181,302	3,987,899
Current liabilities		
Accounts payable and accrued liabilities	423,726	266,208
Other current liabilities	301,824	413,640
Short-term debt	—	126,100
Current maturities of long-term debt	352,434	360,131
Total current liabilities	1,077,984	1,166,079
Deferred income taxes	944,605	829,128
Regulatory cost of removal obligation	364,709	350,521
Deferred credits and other liabilities	427,224	430,164
	$6,995,824	$6,763,791

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2011	2010
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,113,204	$1,365,988
Regulated transmission and storage segment	54,976	55,181
Nonregulated segment	583,531	677,032
Intersegment eliminations	(134,424)	(157,935)
	1,617,287	1,940,266
Purchased gas cost		
Natural gas distribution segment	723,046	980,603
Regulated transmission and storage segment	—	—
Nonregulated segment	563,473	662,871
Intersegment eliminations	(134,054)	(157,529)
	1,152,465	1,485,945
Gross profit	464,822	454,321
Operating expenses		
Operation and maintenance	116,379	117,088
Depreciation and amortization	57,136	53,080
Taxes, other than income	54,103	59,613
Asset impairment	19,282	—
Total operating expenses	246,900	229,781
Operating income	217,922	224,540
Miscellaneous income	26,187	49
Interest charges	37,892	39,582
Income before income taxes	206,217	185,007
Income tax expense	74,008	70,881
Net income	$ 132,209	$ 114,126
Basic net income per share	$ 1.45	$ 1.22
Diluted net income per share	$ 1.45	$ 1.22
Cash dividends per share	$ 0.340	$ 0.335
Weighted average shares outstanding:		
Basic	90,246	92,518
Diluted	90,533	92,853

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2011	2010
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$1,840,399	$2,168,882
Regulated transmission and storage segment	103,983	102,041
Nonregulated segment	1,059,171	1,225,048
Intersegment eliminations	(229,271)	(262,853)
	2,774,282	3,233,118
Purchased gas cost		
Natural gas distribution segment	1,150,469	1,488,870
Regulated transmission and storage segment	—	—
Nonregulated segment	1,013,935	1,141,112
Intersegment eliminations	(228,504)	(262,034)
	1,935,900	2,367,948
Gross profit	838,382	865,170
Operating expenses		
Operation and maintenance	232,973	240,950
Depreciation and amortization	113,297	106,919
Taxes, other than income	94,799	102,165
Asset impairment	19,282	—
Total operating expenses	460,351	450,034
Operating income	378,031	415,136
Miscellaneous income (expense)	25,450	(220)
Interest charges	76,809	78,290
Income before income taxes	326,672	336,626
Income tax expense	120,466	129,170
Net income	$ 206,206	$ 207,456
Basic net income per share	$ 2.26	$ 2.22
Diluted net income per share	$ 2.26	$ 2.22
Cash dividends per share	$ 0.680	$ 0.670
Weighted average shares outstanding:		
Basic	90,157	92,336
Diluted	90,455	92,681

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2011	2010
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 206,206	$ 207,456
Adjustments to reconcile net income to net cash provided by operating activities:		
Asset impairment	19,282	—
Depreciation and amortization:		
Charged to depreciation and amortization	113,297	106,919
Charged to other accounts	98	96
Deferred income taxes	115,302	44,097
Other	10,255	11,759
Net assets/liabilities from risk management activities	(17,478)	1,234
Net change in operating assets and liabilities	(8,491)	111,897
Net cash provided by operating activities	438,471	483,458
Cash Flows From Investing Activities		
Capital expenditures	(246,663)	(232,629)
Other, net	(1,535)	(946)
Net cash used in investing activities	(248,198)	(233,575)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(128,884)	(75,907)
Unwinding of Treasury lock agreements	27,803	—
Repayment of long-term debt	(10,066)	(66)
Cash dividends paid	(62,067)	(62,550)
Repurchase of equity awards	(3,333)	—
Issuance of common stock	7,568	8,590
Net cash used in financing activities	(168,979)	(129,933)
Net increase in cash and cash equivalents	21,294	119,950
Cash and cash equivalents at beginning of period	131,952	111,203
Cash and cash equivalents at end of period	$ 153,246	$ 231,153

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2011

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc, (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

As discussed in Note 10, we operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2011 are not indicative of our results of operations for the full 2011 fiscal year, which ends September 30, 2011.

We have evaluated subsequent events from the March 31, 2011 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). Except as discussed in

Note 5, no events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010.

During the second quarter of fiscal 2011, we recognized a $5.0 million one-time tax benefit related to the administrative settlement of various income tax positions.

Additionally, during the second quarter of fiscal 2011, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

During the six months ended March 31, 2011, two new accounting standards became applicable to the Company pertaining to goodwill impairment testing for reporting units with zero or negative carrying amounts and disclosure of supplementary pro forma information for business combinations. The adoption of these standards did not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the six months ended March 31, 2011.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of March 31, 2011 and September 30, 2010 included the following:

	March 31, 2011	September 30, 2010
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$203,136	$209,564
Merger and integration costs, net	6,478	6,714
Deferred gas costs	34,211	22,701
Regulatory cost of removal asset	38,973	31,014
Environmental costs	509	805
Rate case costs	5,648	4,505
Deferred franchise fees	415	1,161
Other	5,101	1,046
	$294,471	$277,510
Regulatory liabilities:		
Deferred gas costs	$ 6,419	$ 43,333
Deferred franchise fees	5,443	—
Regulatory cost of removal obligation	396,388	381,474
Other	5,912	6,112
	$414,162	$430,919

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

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month and six-month periods ended March 31, 2011 and 2010:

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
	(In thousands)			
Net income	$132,209	$114,126	$206,206	$207,456
Unrealized holding gains on investments, net of tax expense of $477 and $408 for the three months ended March 31, 2011 and 2010 and of $932 and $798 for the six months ended March 31, 2011 and 2010	810	695	1,586	1,359
Amortization, unrealized gain and unwinding of interest rate hedging transactions, net of tax expense (benefit) of $(6,125) and $248 for the three months ended March 31, 2011 and 2010 and $12,579 and $496 for the six months ended March 31, 2011 and 2010	(10,427)	421	21,420	843
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $2,573 and $(6,321) for the three months ended March 31, 2011 and 2010 and $9,190 and $(2,067) for the six months ended March 31, 2011 and 2010	4,025	(9,885)	14,375	(3,231)
Comprehensive income	$126,617	$105,357	$243,587	$206,427

Accumulated other comprehensive income (loss), net of tax, as of March 31, 2011 and September 30, 2010 consisted of the following unrealized gains (losses):

	March 31, 2011	September 30, 2010
	(In thousands)	
Accumulated other comprehensive income (loss):		
Unrealized holding gains on investments	$ 5,791	$ 4,205
Treasury lock agreements	15,952	(5,468)
Cash flow hedges	(7,734)	(22,109)
	$14,009	$(23,372)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the second quarter there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2010-2011 heating season, in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 35 percent, or 31.7 Bcf of the planned winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver 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.

We also perform asset optimization activities in our nonregulated segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated segment is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a

fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 59 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on March 31, 2011, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.4 Bcf.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

We intend to refinance our $350 million unsecured 7.375% Senior Notes that will mature in May 2011 through the issuance of $300 million 30-year unsecured senior notes in June 2011. In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes which were designated as cash flow hedges of an anticipated transaction.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges of an anticipated transaction. Due to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November has been eliminated and the related Treasury lock agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pretax cash gain of $27.8 million during the second quarter.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks were settled at various times at a cumulative net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2035. However, the majority of the remaining amounts associated with the settled Treasury locks will be recognized by the end of fiscal 2019.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of March 31, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of March 31, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(20,483)
	Cash Flow	—	27,276
	Not designated	6,973	26,672
		6,973	33,465

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of March 31, 2011 and September 30, 2010. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $17.1 million and $24.9 million of cash held on deposit in margin accounts as of March 31, 2011 and September 30, 2010 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the

amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
			(In thousands)		
March 31, 2011					
Designated As Hedges:					
Asset Financial Instruments					
Current commodity and interest rate contracts	Other current assets	$33,207	$ —	$ 12,807	$ 46,014
Noncurrent commodity contracts	Deferred charges and other assets	—	—	574	574
Liability Financial Instruments					
Current commodity contracts	Other current liabilities	—	—	(21,303)	(21,303)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	—	(5,857)	(5,857)
Total		33,207	—	(13,779)	19,428
Not Designated As Hedges:					
Asset Financial Instruments					
Current commodity contracts	Other current assets	716	—	10,035	10,751
Noncurrent commodity contracts	Deferred charges and other assets	—	—	2,761	2,761
Liability Financial Instruments					
Current commodity contracts	Other current liabilities	(3,390)	—	(10,660)	(14,050)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	—	(1,299)	(1,299)
Total		(2,674)	—	837	(1,837)
Total Financial Instruments		$30,533	$ —	$(12,942)	$ 17,591

	Balance Sheet Location	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
			(In thousands)		
September 30, 2010					
Designated As Hedges:					
Asset Financial Instruments					
Current commodity contracts	Other current assets	$ —	$ —	$ 40,030	$ 40,030
Noncurrent commodity contracts	Deferred charges and other assets	—	—	2,461	2,461
Liability Financial Instruments					
Current commodity contracts	Other current liabilities	—	—	(56,575)	(56,575)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	—	(9,222)	(9,222)
Total		—	—	(23,306)	(23,306)
Not Designated As Hedges:					
Asset Financial Instruments					
Current commodity contracts	Other current assets	2,219	—	16,459	18,678
Noncurrent commodity contracts	Deferred charges and other assets	47	—	2,056	2,103
Liability Financial Instruments					
Current commodity contracts	Other current liabilities	(48,942)	—	(7,178)	(56,120)
Noncurrent commodity contracts	Deferred credits and other liabilities	(2,924)	—	(405)	(3,329)
Total		(49,600)	—	10,932	(38,668)
Total Financial Instruments		$(49,600)	$ —	$(12,374)	$(61,974)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged

item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended March 31, 2011 and 2010 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $4.1 million and $(4.9) million. For the six months ended March 31, 2011 and 2010 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $17.5 million and $40.4 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2011 and 2010 is presented below.

	Three Months Ended March 31	
	2011	2010
	(In thousands)	
Commodity contracts	$(1,279)	$ 33,461
Fair value adjustment for natural gas inventory designated as the hedged item	5,586	(37,666)
Total impact on revenue	$ 4,307	$ (4,205)
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ (509)	$ (512)
Timing ineffectiveness	4,816	(3,693)
	$ 4,307	$ (4,205)

	Six Months Ended March 31	
	2011	2010
	(In thousands)	
Commodity contracts	$ (3,003)	$30,821
Fair value adjustment for natural gas inventory designated as the hedged item	21,211	11,517
Total impact on revenue	$18,208	$42,338
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ 412	$ (449)
Timing ineffectiveness	17,796	42,787
	$18,208	$42,338

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot to forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 2011 and 2010 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended March 31, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(7,328)	$ (7,328)
Loss arising from ineffective portion of commodity contracts	—	—	(233)	(233)
Total impact on revenue	—	—	(7,561)	(7,561)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(669)	—	—	(669)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total Impact from Cash Flow Hedges	$21,134	$6,000	$(7,561)	$19,573

	Three Months Ended March 31, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(8,556)	$(8,556)
Loss arising from ineffective portion of commodity contracts	—	—	(739)	(739)
Total impact on revenue	—	—	(9,295)	(9,295)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(669)	—	—	(669)
Total Impact from Cash Flow Hedges	$(669)	$ —	$(9,295)	$(9,964)

	Six Months Ended March 31, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(21,581)	$(21,581)
Loss arising from ineffective portion of commodity contracts	—	—	(677)	(677)
Total impact on revenue	—	—	(22,258)	(22,258)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,339)	—	—	(1,339)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total Impact from Cash Flow Hedges	$20,464	$6,000	$(22,258)	$ 4,206

	Six Months Ended March 31, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(31,673)	$(31,673)
Loss arising from ineffective portion of commodity contracts	—	—	(1,957)	(1,957)
Total impact on revenue	—	—	(33,630)	(33,630)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,339)	—	—	(1,339)
Total Impact from Cash Flow Hedges	$(1,339)	$ —	$(33,630)	$(34,969)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 2011 and 2010. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$ 6,667	$ —	$ 38,092	$ —
Forward commodity contracts	(446)	(15,104)	1,211	(22,551)
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	(17,094)	421	(16,672)	843
Forward commodity contracts	4,471	5,219	13,164	19,320
Total other comprehensive income (loss) from hedging, net of tax[1]	$ (6,402)	$ (9,464)	$ 35,795	$ (2,388)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Deferred losses recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2011. However, the table below does not include the expected recognition in earnings of three Treasury lock agreements entered into on September 30, 2010 related to the anticipated issuance of long-term debt in June 2011 as those instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,687)	$(4,588)	$ (6,275)
Thereafter	(3,281)	(3,146)	(6,427)
Total[1]	$(4,968)	$(7,734)	$(12,702)

(1) Utilizing an income tax rate of approximately 37 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended March 31, 2011 and 2010 was an increase (decrease) in revenue of $4.0 million and $(3.0) million. For the six months ended March 31, 2011 and 2010 revenue increased $8.2 million and $12.3 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the three and six months ended March 31, 2011, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 8 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2010.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2011 and

September 30, 2010. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	March 31, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$33,923	$ —	$ —	$ 33,923
Nonregulated segment	4,375	21,802	—	(15,023)	11,154
Total financial instruments	4,375	55,725	—	(15,023)	45,077
Hedged portion of gas stored underground	84,629	—	—	—	84,629
Available-for-sale securities	43,453	—	—	—	43,453
Total assets	$132,457	$55,725	$ —	$(15,023)	$173,159
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 3,390	$ —	$ —	$ 3,390
Nonregulated segment	15,668	23,451	—	(32,076)	7,043
Total liabilities	$ 15,668	$26,841	$ —	$(32,076)	$ 10,433

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,266	$ —	$ —	$ 2,266
Nonregulated segment	18,544	42,462	—	(41,760)	19,246
Total financial instruments	18,544	44,728	—	(41,760)	21,512
Hedged portion of gas stored underground	57,507	—	—	—	57,507
Available-for-sale securities	41,466	—	—	—	41,466
Total assets	$117,517	$44,728	$ —	$(41,760)	$120,485
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,866	$ —	$ —	$ 51,866
Nonregulated segment	41,430	31,950	—	(66,649)	6,731
Total liabilities	$ 41,430	$83,816	$ —	$(66,649)	$ 58,597

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these

assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of March 31, 2011, we had $17.1 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $9.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $7.5 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of March 31, 2011:

	March 31, 2011
	(In thousands)
Carrying Amount	$2,162,630
Fair Value	$2,370,532

5. Debt

Long-term debt

Long-term debt at March 31, 2011 and September 30, 2010 consisted of the following:

	March 31, 2011	September 30, 2010
	(In thousands)	
Unsecured 7.375% Senior Notes, due May 2011	$ 350,000	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due December 2010	—	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term note due in installments through 2013	327	393
Total long-term debt	2,162,630	2,172,696
Less:		
Original issue discount on unsecured senior notes and debentures	(2,873)	(3,014)
Current maturities	(352,434)	(360,131)
	$1,807,323	$1,809,551

As noted above, our Unsecured 7.375% Senior Notes will mature in May 2011 and our Unsecured 10% Notes will mature in December 2011; accordingly, these have been classified within the current maturities of long-term debt.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

As of March 31, 2011, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. On April 13, 2011, our $200 million 180-day unsecured credit facility expired and was not replaced. On May 2, 2011, we replaced our $566.7 million unsecured credit facility with a new five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion. As a result of these changes, we have $975 million of working capital funding from our commercial paper program and three committed revolving credit facilities with third-party lenders.

At March 31, 2011, there were no short-term debt borrowings outstanding. At September 30, 2010, there was a total of $126.1 million outstanding under our commercial paper program. We also use intercompany

credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

Through March 31, 2011 we funded our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provided approximately $800 million of working capital funding. The first facility was a five-year $566.7 million unsecured facility that was replaced on May 2, 2011 with a new five-year $750 million unsecured credit facility. The former facility bore interest at a base rate or at a LIBOR- based rate for the applicable interest period, plus a spread ranging from 0.30 percent to 0.75 percent, based on the Company's credit ratings. At March 31, 2011, there were no borrowings under this facility nor was there any commercial paper outstanding. The new credit facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 2 percent, based on the Company's credit ratings. This new credit facility also serves as a backup liquidity facility for our commercial paper program.

The second facility was a $200 million unsecured 180-day facility that expired in April 2011 and was not replaced. The facility bore interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from 1.50 percent to 2.75 percent, based on the Company's credit ratings. At March 31, 2011, there were no borrowings outstanding under this facility.

The third facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility was renewed effective April 1, 2011. At March 31, 2011, there were no borrowings outstanding under this facility.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2011, our total-debt-to-total-capitalization ratio, as defined, was 50 percent. In addition, both the interest margin over the Eurodollar rate and the fees that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $350 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility, (ii) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the 180-day revolving credit facility or (iii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There was $163.9 million outstanding under this facility at March 31, 2011.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), a wholly-owned subsidiary of AEH has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas

from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At March 31, 2011, there were no borrowings outstanding under this credit facility. However, at March 31, 2011, AEM letters of credit totaling $35.6 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 $114.4 million at March 31, 2011.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At March 31, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.4 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at March 31, 2011, AEM's net working capital was $137.9 million and its tangible net worth was $150.6 million.

To supplement borrowings under this facility, AEH has a $350 million intercompany demand credit facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There were no borrowings outstanding under this facility at March 31, 2011.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities. At March 31, 2011, no securities have been issued under the shelf registration statement.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of March 31, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and six months ended March 31, 2011 and 2010 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
	(In thousands, except per share amounts)			
Basic Earnings Per Share				
Net income	$132,209	$114,126	$206,206	$207,456
Less: Income allocated to participating securities	1,384	1,142	2,162	2,088
Net income available to common shareholders	$130,825	$112,984	$204,044	$205,368
Basic weighted average shares outstanding	90,246	92,518	90,157	92,336
Net income per share — Basic	$ 1.45	$ 1.22	$ 2.26	$ 2.22
Diluted Earnings Per Share				
Net income available to common shareholders	$130,825	$112,984	$204,044	$205,368
Effect of dilutive stock options and other shares	3	3	5	5
Net income available to common shareholders	$130,828	$112,987	$204,049	$205,373
Basic weighted average shares outstanding	90,246	92,518	90,157	92,336
Additional dilutive stock options and other shares	287	335	298	345
Diluted weighted average shares outstanding	90,533	92,853	90,455	92,681
Net income per share — Diluted	$ 1.45	$ 1.22	$ 2.26	$ 2.22

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2010 and 2011 as their exercise price was less than the average market price of the common stock during that period.

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received and retired 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. As a result of this transaction, beginning in our fourth fiscal quarter of 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and six months ended March 31, 2011 and 2010 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the election period, a limited number of participants chose to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. The curtailment gain was recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,257	$ 3,994	$3,601	$3,359
Interest cost	7,055	6,523	3,203	3,017
Expected return on assets	(6,285)	(6,320)	(682)	(615)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(105)	(194)	(363)	(375)
Amortization of actuarial loss	2,748	2,823	86	94
Curtailment gain	(40)	—	—	—
Net periodic pension cost	$ 7,630	$ 6,826	$6,223	$5,858

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 8,637	$ 7,987	$ 7,202	$ 6,719
Interest cost	13,979	13,047	6,406	6,035
Expected return on assets	(12,248)	(12,640)	(1,364)	(1,230)
Amortization of transition asset	—	—	756	756
Amortization of prior service cost	(217)	(387)	(725)	(750)
Amortization of actuarial loss	6,242	5,645	173	187
Curtailment gain	(40)	—	—	—
Net periodic pension cost	$ 16,353	$ 13,652	$12,448	$11,717

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2011 and 2010 are as follows:

	Pension Account Plan		Other Pension Benefits		Other Benefits	
	2011	2010	2011	2010	2011	2010
Discount rate	5.68%	5.52%	5.39%	5.52%	5.39%	5.52%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we expect we will be required to contribute less than $2 million to our pension plans by September 15, 2011.

We contributed $5.6 million to our other post-retirement benefit plans during the six months ended March 31, 2011. We expect to contribute a total of approximately $11 million to these plans during fiscal 2011.

For our Supplemental Executive Retirement Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of March 31, 2011:				
Domestic equity mutual funds	$29,118	$7,744	$ —	$36,862
Foreign equity mutual funds	4,515	1,448	—	5,963
Money market funds	628	—	—	628
	$34,261	$9,192	$ —	$43,453
As of September 30, 2010:				
Domestic equity mutual funds	$29,540	$5,698	$ —	$35,238
Foreign equity mutual funds	4,753	976	—	5,729
Money market funds	499	—	—	499
	$34,792	$6,674	$ —	$41,466

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 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2011. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC, have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On

March 30, 2011, we filed a notice of appeal of this ruling. We strongly believe that the trial court erred in not granting our motion to dismiss the lawsuit prior to trial and that the verdict is unsupported by law. After consultation with counsel, we believe that it is probable that any judgment based on this verdict would be overturned on appeal.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued does not reflect the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At March 31, 2011, AEH was committed to purchase 92.8 Bcf within one year, 37.6 Bcf within one to three years and 4.5 Bcf after three years under indexed contracts. AEH is committed to purchase 1.6 Bcf within one year and 0.4 Bcf within one to three years under fixed price contracts with prices ranging from $4.02 to $6.36 per Mcf. Purchases under these contracts totaled $438.9 million and $538.6 million for the three months ended March 31, 2011 and 2010 and $773.1 million and $892.7 million for the six months ended March 31, 2011 and 2010.

Our natural gas distribution divisions, except for our 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 and fixed prices. The estimated commitments under these contracts as of March 31, 2011 are as follows (in thousands):

2011	$ 67,814
2012	94,485
2013	5,294
2014	1,863
2015	—
Thereafter	—
	$169,456

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. There were no material changes to the estimated storage and transportation fees for the six months ended March 31, 2011.

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. There have been no material developments in this matter during the six months ended March 31, 2011. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities our Mid-Tex Division serves have agreed to a program of installing 100,000 replacements during the next two years, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing 14,939 lines for a cost of $21.7 million as of March 31, 2011. The program is progressing on schedule for completion in September 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

As of March 31, 2011, rate cases were in progress in our Atmos Pipeline — Texas service area and an annual rate filing mechanism was in progress in our Mississippi service area. In addition, there were other ratemaking activities in progress in our Mid-Tex, West Texas, Georgia and Louisiana service areas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments* and *Regulated Transmission and Storage Segment.*

Other Matters

As we previously discussed in Note 9 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011, accordingly, the option was terminated. We have evaluated our strategic alternatives and concluded the project's returns do not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pretax noncash impairment loss to write off substantially all of our investment in the project.

9. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the six months ended March 31, 2011, there were no material changes in our concentration of credit risk.

10. Segment Information

Through November 30, 2010, our operations were divided into four segments:

- The *natural gas distribution segment*, which included our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which included the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which included a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which included our nonregulated natural gas gathering transmission and storage services.

As a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- The *natural gas distribution segment*, remains unchanged and includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, remains unchanged and includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services which were previously reported in the natural gas marketing and pipeline, storage and other segments.

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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2010. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six month periods ended March 31, 2011 and 2010 by segment are presented in the following tables to reflect our business structure as of March 31, 2011. Prior-year amounts have been restated accordingly.

	Three Months Ended March 31, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,112,968	$21,597	$482,722	$ —	$1,617,287
Intersegment revenues	236	33,379	100,809	(134,424)	—
	1,113,204	54,976	583,531	(134,424)	1,617,287
Purchased gas cost	723,046	—	563,473	(134,054)	1,152,465
Gross profit	390,158	54,976	20,058	(370)	464,822
Operating expenses					
Operation and maintenance	94,483	15,231	7,035	(370)	116,379
Depreciation and amortization	50,224	5,798	1,114	—	57,136
Taxes, other than income	50,633	4,113	(643)	—	54,103
Asset impairment	—	—	19,282	—	19,282
Total operating expenses	195,340	25,142	26,788	(370)	246,900
Operating income (loss)	194,818	29,834	(6,730)	—	217,922
Miscellaneous income (expense)	20,141	5,861	306	(121)	26,187
Interest charges	29,622	8,085	306	(121)	37,892
Income (loss) before income taxes	185,337	27,610	(6,730)	—	206,217
Income tax expense (benefit)	66,727	9,871	(2,590)	—	74,008
Net income (loss)	$ 118,610	$17,739	$ (4,140)	$ —	$ 132,209
Capital expenditures	$ 109,762	$11,818	$ 1,921	$ —	$ 123,501

	Three Months Ended March 31, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,365,736	$21,643	$552,887	$ —	$1,940,266
Intersegment revenues	252	33,538	124,145	(157,935)	—
	1,365,988	55,181	677,032	(157,935)	1,940,266
Purchased gas cost	980,603	—	662,871	(157,529)	1,485,945
Gross profit	385,385	55,181	14,161	(406)	454,321
Operating expenses					
Operation and maintenance	87,542	20,248	9,704	(406)	117,088
Depreciation and amortization	46,748	5,282	1,050	—	53,080
Taxes, other than income	55,531	2,949	1,133	—	59,613
Total operating expenses	189,821	28,479	11,887	(406)	229,781
Operating income	195,564	26,702	2,274	—	224,540
Miscellaneous income (expense)	776	(20)	637	(1,344)	49
Interest charges	29,256	7,954	3,716	(1,344)	39,582
Income (loss) before income taxes	167,084	18,728	(805)	—	185,007
Income tax expense (benefit)	64,353	6,658	(130)	—	70,881
Net income (loss)	$ 102,731	$12,070	$ (675)	$ —	$ 114,126
Capital expenditures	$ 95,765	$20,063	$ 1,362	$ —	$ 117,190

	Six Months Ended March 31, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,839,962	$ 42,830	$ 891,490	$ —	$2,774,282
Intersegment revenues	437	61,153	167,681	(229,271)	—
	1,840,399	103,983	1,059,171	(229,271)	2,774,282
Purchased gas cost	1,150,469	—	1,013,935	(228,504)	1,935,900
Gross profit	689,930	103,983	45,236	(767)	838,382
Operating expenses					
Operation and maintenance	185,816	30,805	17,119	(767)	232,973
Depreciation and amortization	99,502	11,597	2,198	—	113,297
Taxes, other than income	85,609	7,666	1,524	—	94,799
Asset impairment	—	—	19,282	—	19,282
Total operating expenses	370,927	50,068	40,123	(767)	460,351
Operating income	319,003	53,915	5,113	—	378,031
Miscellaneous income	19,432	5,579	596	(157)	25,450
Interest charges	59,341	16,149	1,476	(157)	76,809
Income before income taxes	279,094	43,345	4,233	—	326,672
Income tax expense	103,166	15,504	1,796	—	120,466
Net income	$ 175,928	$ 27,841	$ 2,437	$ —	$ 206,206
Capital expenditures	$ 219,261	$ 24,557	$ 2,845	$ —	$ 246,663

	Six Months Ended March 31, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$2,168,422	$ 41,485	$1,023,211	$ —	$3,233,118
Intersegment revenues	460	60,556	201,837	(262,853)	—
	2,168,882	102,041	1,225,048	(262,853)	3,233,118
Purchased gas cost	1,488,870	—	1,141,112	(262,034)	2,367,948
Gross profit	680,012	102,041	83,936	(819)	865,170
Operating expenses					
Operation and maintenance	183,575	37,827	20,367	(819)	240,950
Depreciation and amortization	94,605	10,224	2,090	—	106,919
Taxes, other than income	93,521	6,216	2,428	—	102,165
Total operating expenses	371,701	54,267	24,885	(819)	450,034
Operating income	308,311	47,774	59,051	—	415,136
Miscellaneous income (expense)	1,433	23	1,013	(2,689)	(220)
Interest charges	58,934	15,922	6,123	(2,689)	78,290
Income before income taxes	250,810	31,875	53,941	—	336,626
Income tax expense	96,631	11,351	21,188	—	129,170
Net income	$ 154,179	$ 20,524	$ 32,753	$ —	$ 207,456
Capital expenditures	$ 196,227	$ 33,822	$ 2,580	$ —	$ 232,629

Balance sheet information at March 31, 2011 and September 30, 2010 by segment is presented to reflect our business structure as of March 31, 2011 in the following tables. Prior-year amounts have been restated accordingly.

	March 31, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,087,399	$760,221	$ 67,030	$ —	$4,914,650
Investment in subsidiaries	665,515	—	(2,096)	(663,419)	—
Current assets					
Cash and cash equivalents	41,436	—	111,810	—	153,246
Assets from risk management activities	33,923	—	10,692	—	44,615
Other current assets	519,521	11,810	432,606	(177,710)	786,227
Intercompany receivables	505,915	—	—	(505,915)	—
Total current assets	1,100,795	11,810	555,108	(683,625)	984,088
Intangible assets	—	—	520	—	520
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	—	—	462	—	462
Deferred charges and other assets	330,253	11,487	15,050	—	356,790
	$6,756,224	$915,859	$670,785	$(1,347,044)	$6,995,824
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,373,979	$240,528	$424,987	$ (665,515)	$2,373,979
Long-term debt	1,807,127	—	196	—	1,807,323
Total capitalization	4,181,106	240,528	425,183	(665,515)	4,181,302
Current liabilities					
Current maturities of long-term debt	352,303	—	131	—	352,434
Short-term debt	163,900	—	—	(163,900)	—
Liabilities from risk management activities	3,390	—	2,760	—	6,150
Other current liabilities	494,037	5,340	231,737	(11,714)	719,400
Intercompany payables	—	505,019	896	(505,915)	—
Total current liabilities	1,013,630	510,359	235,524	(681,529)	1,077,984
Deferred income taxes	779,026	159,764	5,815	—	944,605
Noncurrent liabilities from risk management activities	—	—	4,283	—	4,283
Regulatory cost of removal obligation	364,709	—	—	—	364,709
Deferred credits and other liabilities	417,753	5,208	(20)	—	422,941
	$6,756,224	$915,859	$670,785	$(1,347,044)	$6,995,824

	September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$3,959,112	$748,947	$ 85,016	$ —	$4,793,075
Investment in subsidiaries	620,863	—	(2,096)	(618,767)	—
Current assets					
Cash and cash equivalents	31,952	—	100,000	—	131,952
Assets from risk management activities	2,219	—	18,356	—	20,575
Other current assets	528,655	19,504	325,348	(150,842)	722,665
Intercompany receivables	546,313	—	—	(546,313)	—
Total current assets	1,109,139	19,504	443,704	(697,155)	875,192
Intangible assets	—	—	834	—	834
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	47	—	890	—	937
Deferred charges and other assets	324,707	13,037	16,695	—	354,439
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,178,348	$212,687	$408,176	$ (620,863)	$2,178,348
Long-term debt	1,809,289	—	262	—	1,809,551
Total capitalization	3,987,637	212,687	408,438	(620,863)	3,987,899
Current liabilities					
Current maturities of long-term debt	360,000	—	131	—	360,131
Short-term debt	258,488	—	—	(132,388)	126,100
Liabilities from risk management activities	48,942	—	731	—	49,673
Other current liabilities	473,076	10,949	162,508	(16,358)	630,175
Intercompany payables	—	543,007	3,306	(546,313)	—
Total current liabilities	1,140,506	553,956	166,676	(695,059)	1,166,079
Deferred income taxes	691,126	142,337	(4,335)	—	829,128
Noncurrent liabilities from risk management activities	2,924	—	6,000	—	8,924
Regulatory cost of removal obligation	350,521	—	—	—	350,521
Deferred credits and other liabilities	413,416	4,849	2,975	—	421,240
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of March 31, 2011, the related condensed consolidated statements of income for the three-month and six-month periods ended March 31, 2011 and 2010, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2011 and 2010. 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, 2010, 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 12, 2010, 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, 2010, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
May 5, 2011

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, 2010.

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

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

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 10, we operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

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, the 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 fiscal year ended September 30, 2010 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the six months ended March 31, 2011.

RESULTS OF OPERATIONS

We reported net income of $132.2 million, or $1.45 per diluted share for the three months ended March 31, 2011 compared with net income of $114.1 million, or $1.22 per diluted share in the prior-year quarter. Unrealized losses reduced net income by $2.1 million, or $0.02 per diluted share for the three months ended March 31, 2011, compared with net unrealized losses of $25.5 million, or $0.27 per diluted share for the prior-year quarter. In addition, net income for the second quarter includes the impact of several one-time items totaling $11.1 million, or $0.12 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $19.3 million unfavorable impact related to the non-cash impairment of assets in the Ft. Necessity storage project.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

Excluding the impact of unrealized margins and one-time items, diluted earnings per share decreased from $1.44 in the prior-year quarter to $1.35 in the current-year quarter, primarily due to decreased asset optimization margins in our nonregulated segment and a decline of 11 percent in consolidated throughput in our natural gas distribution segment.

We reported net income of $206.2 million, or $2.26 per diluted share for the six months ended March 31, 2011 compared with net income of $207.5 million, or $2.22 per diluted share in the prior-year period. Unrealized losses reduced net income by $1.7 million, or $0.02 per diluted share for the six months ended March 31, 2011. Regulated operations contributed 99 percent of our net income during this period with our nonregulated operations contributing the remaining 1 percent. The primary driver in the year-over-year decrease in net income was decreased asset optimization margins in our nonregulated segment and a decline of 11 percent in consolidated throughput in our natural gas distribution segment.

On March 4, 2011, we received and retired 375,468 common shares from Goldman Sachs & Co under our accelerated share repurchase agreement that commenced in the fourth quarter of fiscal 2010. The receipt and retirement of these additional shares concluded our share repurchase agreement under which we paid a total of $100 million and received and retired an aggregate of 3,334,048 common shares. As a result of this transaction, our weighted-average shares outstanding used to calculate our earnings per share were reduced by the number of shares repurchased as they were delivered to us.

During the six months ended March 31, 2011, we executed on our strategy to streamline our credit facilities. In October 2010, we replaced our $200 million 364-day revolving credit agreement prior to its expiration with a $200 million 180-day revolving credit agreement, which expired in April 2011. As planned, we did not replace or extend this agreement. Additionally, in December 2010, we replaced Atmos Energy Marketing's (AEM) $450 million 364-day revolving credit facility with a $200 million three-year facility with an accordion feature that could increase AEM's borrowing capacity to $500 million. Finally, on May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility that contains an accordion feature that could increase our borrowing capacity to $1.0 billion. After giving effect to these changes, we now have $975 million of liquidity available to us from our commercial paper program and three committed credit facilities and have reduced our financing costs. We believe this availability provides sufficient liquidity to fund our working capital needs.

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2011 and 2010:

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
	(In thousands, except per share data)			
Operating revenues	$1,617,287	$1,940,266	$2,774,282	$3,233,118
Gross profit	464,822	454,321	838,382	865,170
Operating expenses	246,900	229,781	460,351	450,034
Operating income	217,922	224,540	378,031	415,136
Miscellaneous income (expense)	26,187	49	25,450	(220)
Interest charges	37,892	39,582	76,809	78,290
Income before income taxes	206,217	185,007	326,672	336,626
Income tax expense	74,008	70,881	120,466	129,170
Net income	$ 132,209	$ 114,126	$ 206,206	$ 207,456
Diluted net income per share	$ 1.45	$ 1.22	$ 2.26	$ 2.22

Our consolidated net income during the three and six months ended March 31, 2011 and 2010 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2011	2010	Change
	(In thousands)		
Natural gas distribution segment	$118,610	$102,731	$15,879
Regulated transmission and storage segment	17,739	12,070	5,669
Nonregulated segment	(4,140)	(675)	(3,465)
Net income	$132,209	$114,126	$18,083

	Six Months Ended March 31		
	2011	2010	Change
	(In thousands)		
Natural gas distribution segment	$175,928	$154,179	$ 21,749
Regulated transmission and storage segment	27,841	20,524	7,317
Nonregulated segment	2,437	32,753	(30,316)
Net income	$206,206	$207,456	$ (1,250)

The following tables segregate our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended March 31		
	2011	2010	Change
	(In thousands, except per share data)		
Regulated operations	$136,349	$114,801	$21,548
Nonregulated operations	(4,140)	(675)	(3,465)
Consolidated net income	$132,209	$114,126	$18,083
Diluted EPS from regulated operations	$ 1.49	$ 1.23	$ 0.26
Diluted EPS from nonregulated operations	(0.04)	(0.01)	(0.03)
Consolidated diluted EPS	$ 1.45	$ 1.22	$ 0.23

	Six Months Ended March 31		
	2011	2010	Change
	(In thousands, except per share data)		
Regulated operations	$203,769	$174,703	$ 29,066
Nonregulated operations	2,437	32,753	(30,316)
Consolidated net income	$206,206	$207,456	$ (1,250)
Diluted EPS from regulated operations	$ 2.23	$ 1.87	$ 0.36
Diluted EPS from nonregulated operations	0.03	0.35	(0.32)
Consolidated diluted EPS	$ 2.26	$ 2.22	$ 0.04

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately,

separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
Virginia	January — December

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

Three Months Ended March 31, 2011 compared with Three Months Ended March 31, 2010

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2011 and 2010 are presented below.

	Three Months Ended March 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Gross profit	$390,158	$385,385	$ 4,773
Operating expenses	195,340	189,821	5,519
Operating income	194,818	195,564	(746)
Miscellaneous income	20,141	776	19,365
Interest charges	29,622	29,256	366
Income before income taxes	185,337	167,084	18,253
Income tax expense	66,727	64,353	2,374
Net income	$118,610	$102,731	$ 15,879
Consolidated natural gas distribution sales volumes — MMcf	136,838	158,530	(21,692)
Consolidated natural gas distribution transportation volumes — MMcf	39,463	39,294	169
Total consolidated natural gas distribution throughput — MMcf	176,301	197,824	(21,523)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.46	$ 0.01
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.28	$ 6.19	$ (0.91)

The following table shows our operating income by natural gas distribution division, in order of total rate base, for the three months ended March 31, 2011 and 2010. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2011	2010	Change
	(In thousands)		
Mid-Tex	$ 82,476	$ 79,843	$ 2,633
Kentucky/Mid-States	35,177	31,000	4,177
Louisiana	23,235	22,831	404
West Texas	19,280	21,400	(2,120)
Colorado-Kansas	15,633	14,267	1,366
Mississippi	18,004	17,852	152
Other	1,013	8,371	(7,358)
Total	$194,818	$195,564	$ (746)

The $4.8 million increase in natural gas distribution gross profit primarily reflects a $17.7 million net increase in rate adjustments, primarily in the Mid-Tex, Missouri, Louisiana, Kentucky, Kansas and Georgia service areas.

These increases in rate adjustments were partially offset by:

- $7.9 million decrease due to an 11 percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather this fiscal year compared to the same period last year in most of our service areas.

- $4.2 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $5.5 million, primarily due to the following:

- $7.4 million increase due to the absence of a state sales tax refund received in the prior year.
- $3.5 million increase in depreciation and amortization expense.

These increases were partially offset by:

- $4.9 million decrease in taxes, other than income, primarily due to lower revenue-related taxes.

Net income for this segment was also favorably impacted by a $21.8 million gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

Six Months Ended March 31, 2011 compared with Six Months Ended March 31, 2010

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2011 and 2010 are presented below.

	Six Months Ended March 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Gross profit	$689,930	$680,012	$ 9,918
Operating expenses	370,927	371,701	(774)
Operating income	319,003	308,311	10,692
Miscellaneous income	19,432	1,433	17,999
Interest charges	59,341	58,934	407
Income before income taxes	279,094	250,810	28,284
Income tax expense	103,166	96,631	6,535
Net income	$175,928	$154,179	$ 21,749
Consolidated natural gas distribution sales volumes — MMcf	223,628	257,844	(34,216)
Consolidated natural gas distribution transportation volumes — MMcf	73,217	74,501	(1,284)
Total consolidated natural gas distribution throughput — MMcf	296,845	332,345	(35,500)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.48	$ 0.46	$ 0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.14	$ 5.77	$ (0.63)

The following table shows our operating income by natural gas distribution division, in order of total rate base, for the six months ended March 31, 2011 and 2010. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2011	2010	Change
	(In thousands)		
Mid-Tex	$139,915	$130,224	$ 9,691
Kentucky/Mid-States	56,540	48,803	7,737
Louisiana	38,196	36,238	1,958
West Texas	28,800	33,157	(4,357)
Colorado-Kansas	23,645	22,873	772
Mississippi	28,219	27,654	565
Other	3,688	9,362	(5,674)
Total	$319,003	$308,311	$10,692

The $9.9 million increase in natural gas distribution gross profit primarily reflects a $31.8 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Missouri, Kentucky, Kansas and Georgia service areas.

These increases were partially offset by:

- $13.2 million decrease due to an 11 percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather this fiscal year compared to the same period last year in most of our service areas.

- $7.0 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $0.8 million, primarily due to the following:

- $7.9 million decrease in taxes, other than income, due to lower revenue-related taxes.

- $5.3 million decrease in employee-related expenses.

- $1.4 million decrease in legal and other administrative costs.

These decreases were partially offset by:

- $7.4 million increase due to the absence of a state sales tax refund received in the prior year.

- $4.9 million increase in depreciation and amortization expense.

Net income also reflects the aforementioned Treasury lock gain and income tax benefit.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the six months ended March 31, 2011 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $25.2 million resulting from ratemaking activity became effective in the six months ended March 31, 2011 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Annual rate filing mechanisms	$23,122
Other rate activity	2,075
	$25,197

Additionally, the following ratemaking efforts were in progress during the second quarter of fiscal 2011 but had not been completed as of March 31, 2011.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	PRP[1]	Georgia	$ 1,192
Louisiana	TransLA RSC[2]	Louisiana	431
	LGS RSC	Louisiana	4,600
Mid-Tex	GRIP[3][4]	Dallas & RRC	3,519
	Rate Review Mechanism (RRM)	Settled Cities	7,687
Mississippi	Annual Rate Filing[5]	Mississippi	—
West Texas	Environs Rate Case	Amarillo	78
	RRM	Lubbock	2,136
	RRM	WT Cities	2,552
	GRIP[3]	RRC	342
			$22,537

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) The Louisiana Commission Staff recommended an increase of $0.4 million effective April 1, 2011, which the Commission accepted.

(3) Gas Reliability Infrastructure Program (GRIP) is a rate adjustment that allows utilities to recover additional invested capital without filing a full rate case.

(4) This GRIP filing is based on a Mid-Tex system-wide basis and made concurrently with the City of Dallas and the Texas Railroad Commission (RRC) for approval of their respective jurisdictional customers.

(5) On April 5, 2011 the Mississippi Public Service Commission approved a Stipulation and Agreement for no increase in operating income.

Rate Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. There were no rate cases completed during the first two quarters of fiscal 2011.

GRIP Filings

GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. There were no GRIP filings completed during the first two quarters of fiscal 2011.

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms (RRM) in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the six months ended March 31, 2011.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2009	$23,122	10/1/2010
Total 2011 Filings			$23,122	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2011:

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2011 Other Rate Activity:				
Kentucky/Mid-States	Georgia	PRP Surcharge	$ 764	10/01/2010
Colorado-Kansas	Colorado	AMI[1]	349	12/01/2010
Colorado-Kansas	Kansas	Ad Valorem[2]	685	01/01/2011
Kentucky/Mid-States	Missouri	ISRS[3]	277	02/14/2011
Total 2011 Other Rate Activity			$2,075	

(1) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of the Company's service area.

(2) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in the Company's base rates.

(3) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, 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.

Three Months Ended March 31, 2011 compared with Three Months Ended March 31, 2010

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2011 and 2010 are presented below.

	Three Months Ended March 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 33,096	$ 33,214	$ (118)
Third-party transportation	16,811	16,335	476
Storage and park and lend services	2,219	2,673	(454)
Other	2,850	2,959	(109)
Gross profit	54,976	55,181	(205)
Operating expenses	25,142	28,479	(3,337)
Operating income	29,834	26,702	3,132
Miscellaneous income (expense)	5,861	(20)	5,881
Interest charges	8,085	7,954	131
Income before income taxes	27,610	18,728	8,882
Income tax expense	9,871	6,658	3,213
Net income	$ 17,739	$ 12,070	$ 5,669
Gross pipeline transportation volumes — MMcf	174,471	192,441	(17,970)
Consolidated pipeline transportation volumes — MMcf	93,493	98,418	(4,925)

The $0.2 million decrease in regulated transmission and storage gross profit was attributable primarily to a $2.7 million decrease due to a nine percent decrease in through-system volumes primarily associated with declines in basis differentials, electric generation demand and Barnett Shale activity and a $0.8 million quarter-over-quarter decrease from lower per-unit transportation margins, partially offset by a $3.1 million increase associated with our GRIP filings.

Operating expenses decreased $3.3 million primarily due to timing of pipeline maintenance activities and other operating expenses.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

On April 18, 2011, the RRC issued an order in the rate case of Atmos Pipeline — Texas that was originally filed in September 2010. The Commission approved an annual operating income increase of $20.4 million as well as the following major provisions that will go into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity
- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly charges.

Six Months Ended March 31, 2011 compared with Six Months Ended March 31, 2010

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2011 and 2010 are presented below.

	Six Months Ended March 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 60,631	$ 59,925	$ 706
Third-party transportation	33,323	31,577	1,746
Storage and park and lend services	4,389	5,278	(889)
Other	5,640	5,261	379
Gross profit	103,983	102,041	1,942
Operating expenses	50,068	54,267	(4,199)
Operating income	53,915	47,774	6,141
Miscellaneous income	5,579	23	5,556
Interest charges	16,149	15,922	227
Income before income taxes	43,345	31,875	11,470
Income tax expense	15,504	11,351	4,153
Net income	$ 27,841	$ 20,524	$ 7,317
Gross pipeline transportation volumes — MMcf	327,649	350,214	(22,565)
Consolidated pipeline transportation volumes — MMcf	193,334	194,356	(1,022)

The $1.9 million increase in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $6.2 million increase associated with our GRIP filings.
- $2.4 million increase in fixed fee services.

These increases were partially offset by the following:

- $3.7 million decrease due to a decline in throughput to our Mid-Tex Division and a reduction in production.
- $2.3 million decrease resulting from lower per-unit transportation margins.

Operating expenses decreased $4.2 million primarily due to timing of pipeline maintenance activities and other expenses.

Miscellaneous income reflects the aforementioned treasury lock gain recognized in March 2011.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas 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 financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEH continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEH may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions and recognize any associated gains or losses at that time. If AEH elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to hedge the original financial instruments. If AEH elects to defer the withdrawal of gas, it will reset its positions by settling the original financial instruments and executing new financial instruments to correspond to the revised withdrawal schedule.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEH also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural

gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Three Months Ended March 31, 2011 compared with Three Months Ended March 31, 2010

Financial and operational highlights for our nonregulated segment for the three months ended March 31, 2011 and 2010 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended March 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 19,170	$ 17,126	$ 2,044
Storage and transportation services	3,522	3,093	429
Other	1,460	2,098	(638)
	24,152	22,317	1,835
Asset optimization[(1)]	(686)	31,385	(32,071)
Total realized margins	23,466	53,702	(30,236)
Unrealized margins	(3,408)	(39,541)	36,133
Gross profit	20,058	14,161	5,897
Operating expenses, excluding asset impairment	7,506	11,887	(4,381)
Asset impairment	19,282	—	19,282
Operating income (loss)	(6,730)	2,274	(9,004)
Miscellaneous income	306	637	(331)
Interest charges	306	3,716	(3,410)
Loss before income taxes	(6,730)	(805)	(5,925)
Income tax benefit	(2,590)	(130)	(2,460)
Net loss	$ (4,140)	$ (675)	$ (3,465)
Gross nonregulated delivered gas sales volumes — MMcf	127,377	123,877	3,500
Consolidated nonregulated delivered gas sales volumes — MMcf	107,566	104,893	2,673
Net physical position (Bcf)	17.7	23.7	(6.0)

(1) Net of storage fees of $3.6 million and $3.9 million.

Realized margins for gas delivery, storage and transportation services and other services were $24.2 million during the three months ended March 31, 2011 compared with $22.3 million, for the prior-year quarter. The increase primarily reflects an increased number of customers in the current-year quarter which resulted in a three percent increase in consolidated delivered gas sales volumes and a $2.0 million increase in margins from gas delivery and related services.

The $32.1 million decrease in realized asset optimization margins from the prior-year quarter reflects the impact of continued weak natural gas market fundamentals, which have reduced price volatility and compressed spot to forward spread values resulting in less favorable trading opportunities. As a result, during the current quarter, AEH captured smaller spread values from its asset optimization activities. This contrasts to the prior quarter, when AEH recognized higher spread values that it had captured from rolling positions through the first quarter of fiscal 2010.

Weak market fundamentals have also reduced the demand and fees paid for storage. During the quarter, AEH started to capitalize on falling storage demand fees by replacing expiring storage contracts with new contracts with lower storage demand fees and allowing non-strategic contracts to expire without renewing them. This should improve AEH's ability to realize gains from its asset optimization activities in future periods.

The decrease in realized asset optimization margins was more than offset by a $36.1 million increase in unrealized margins that reflects the quarter-over-quarter timing of realized margins coupled with lower natural gas price volatility.

Operating expenses decreased $4.4 million primarily due to lower employee-related expenses.

An asset impairment charge of $19.3 million was recorded in March 2011 related to our investment in Fort Necessity. As we previously discussed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011, accordingly, the option was terminated. We have evaluated our strategic alternatives and concluded the project's returns do not meet our investment objectives. As such, we recorded a pretax noncash impairment to write off substantially all of our investment in the project during the second quarter of fiscal 2011.

Interest charges decreased $3.4 million primarily due to a decrease in intercompany borrowings.

Six Months Ended March 31, 2011 compared with Six Months Ended March 31, 2010

Financial and operational highlights for our nonregulated segment for the six months ended March 31, 2011 and 2010 are presented below.

	Six Months Ended March 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 35,211	$ 33,213	$ 1,998
Storage and transportation services	6,871	6,427	444
Other	2,779	2,562	217
	44,861	42,202	2,659
Asset optimization[(1)]	3,279	37,391	(34,112)
Total realized margins	48,140	79,593	(31,453)
Unrealized margins	(2,904)	4,343	(7,247)
Gross profit	45,236	83,936	(38,700)
Operating expenses, excluding asset impairment	20,841	24,885	(4,044)
Asset impairment	19,282	—	19,282
Operating income	5,113	59,051	(53,938)
Miscellaneous income	596	1,013	(417)
Interest charges	1,476	6,123	(4,647)
Income before income taxes	4,233	53,941	(49,708)
Income tax expense	1,796	21,188	(19,392)
Net income	$ 2,437	$ 32,753	$(30,316)
Gross nonregulated delivered gas sales volumes — MMcf	235,089	226,138	8,951
Consolidated nonregulated delivered gas sales volumes — MMcf	202,104	192,122	9,982
Net physical position (Bcf)	17.7	23.7	(6.0)

(1) Net of storage fees of $6.9 million and $6.7 million.

Realized margins for gas delivery, storage and transportation services and other services were $44.9 million, or 93 percent of total realized margins during the six months ended March 31, 2011 compared with $42.2 million, or 53 percent of total realized margins for the prior-year period. The increase primarily reflects a five percent increase in consolidated delivered gas sales volumes and a $2.0 million increase in margins from gas delivery and related services, attributable to an increased number of customers in the current year.

The $34.1 million decrease in realized asset optimization margins from the prior-year period primarily reflects greater intramonth trading gains realized in the prior-year period from more favorable trading opportunities in the daily cash market, combined with lower realized gains in the current-year period due to continued weak natural gas market fundamentals.

Unrealized margins decreased $7.2 million in the current period compared to the prior-year period. The decrease primarily reflects higher unrealized losses on certain basis swaps.

Operating expenses decreased $4.0 million primarily due to lower employee expenses.

Asset impairment includes the aforementioned pre-tax impairment charge related to the substantial write-off of the Fort Necessity project.

Interest charges decreased $4.6 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEH monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEH's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEH's economic value and its potential gross profit (loss) at March 31, 2011 and 2010.

	March 31	
	2011	2010
	(In millions, unless otherwise noted)	
Economic value	$ —	$ 0.8
Associated unrealized losses	9.1	9.5
Subtotal	9.1	10.3
Related fees[(1)]	(16.5)	(14.2)
Potential gross profit (loss)	$ (7.4)	$ (3.9)
Net physical position (Bcf)	17.7	23.7

(1) Related fees represent the contractual costs to acquire the storage capacity utilized in our nonregulated segment's asset optimization activities. The fees primarily consist of demand fees and contractual obligations to sell gas below market index prices in exchange for the right to manage and optimize third party storage assets for the positions we have entered into as of March 31, 2011 and 2010.

During the six months ended March 31, 2011, our nonregulated segment's economic value increased from ($7.5) million, or ($0.48)/Mcf at September 30, 2010 to $0.0 million, or ($0.00)/Mcf. This compares unfavorably to economic value at March 31, 2010 of $0.8 million, or $0.03/Mcf.

For the six months ended March 31, 2011, the increase in our economic value reflected an increase in spread value resulting from realizing financial instruments with lower spread values, entering into financial hedges with higher average prices and rolling financial instruments to forward periods to capture incremental value. Additionally, as a result of falling natural gas prices, we injected a net 2.0 Bcf during the six months ended March 31, 2011, which reduced the weighted average cost of gas held in storage.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEH actively

manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit calculated as of March 31, 2011 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. During fiscal 2011, we have been executing our strategy of consolidating our short-term facilities used for our regulated operations into a single line of credit. In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement. On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion. In our nonregulated segment, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility in December 2010. As a result of these changes, we now have $975 million of availability from our commercial paper program and three committed revolving credit facilities with third parties.

Our $350 million unsecured 7.375% Senior Notes will mature in May 2011. We intend to refinance this debt on a long-term basis through the issuance of $300 million 30-year unsecured senior notes in June 2011. On September 30, 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Any realized gain or loss incurred when these agreements are settled will be recognized as a component of interest expense over the life of the related long-term debt.

Additionally, we had planned to issue $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges of an anticipated transaction. Due to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November has been eliminated and the related Treasury lock agreements have been unwound. A pretax cash gain of approximately $28 million was recorded in March 2011.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2011.

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, investing and financing activities for the six months ended March 31, 2011 and 2010 are presented below.

	Six Months Ended March 31		
	2011	2010	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 438,471	$ 483,458	$(44,987)
Investing activities	(248,198)	(233,575)	(14,623)
Financing activities	(168,979)	(129,933)	(39,046)
Change in cash and cash equivalents	21,294	119,950	(98,656)
Cash and cash equivalents at beginning of period	131,952	111,203	20,749
Cash and cash equivalents at end of period	$ 153,246	$ 231,153	$(77,907)

Cash flows from operating activities

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

For the six months ended March 31, 2011, we generated operating cash flow of $438.5 million from operating activities compared with $483.5 million for the six months ended March 31, 2010. The $45.0 million decrease in operating cash flows primarily reflects the timing of customer collections and vendor payments, coupled with the timing of gas cost recovery under our purchased gas cost mechanisms.

Cash flows from investing activities

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

Capital expenditures for fiscal 2011 are expected to range from $580 million to $595 million. For the six months ended March 31, 2011, capital expenditures were $246.7 million compared with $232.6 million for the six months ended March 31, 2010. The $14.1 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and the development of a new customer service system in the current year, partially offset by the costs incurred in the prior fiscal year to relocate the company's information technology data center.

Cash flows from financing activities

For the six months ended March 31, 2011, our financing activities used $169.0 million of cash compared with $129.9 million of cash used in the prior-year period, primarily due to higher cash outflows associated with repayment of our short-term and long-term debt instruments and repurchases of equity awards, as follows:

- $53.0 million for short-term debt repayments. In the current-year period, $128.9 million of short-term debt was repaid, compared with $75.9 million in the prior-year period.

- $10.0 million for scheduled long-term debt repayments. In the current-year period $10.1 million of long-term debt was repaid compared with $0.1 million of long-term debt in the prior-year period.
- $3.3 million for the repurchase of equity awards.

The higher repayment activity was partially offset by:

- $27.8 million cash received in March 2011 related to the unwinding of two Treasury locks.

The following table summarizes our share issuances for the six months ended March 31, 2011 and 2010.

	Six Months Ended March 31	
	2011	2010
Shares issued:		
Direct Stock Purchase Plan	—	103,529
Retirement Savings Plan and Trust	—	79,722
1998 Long-Term Incentive Plan	663,555	409,535
Outside Directors Stock-for-Fee Plan	1,232	2,040
Total shares issued	664,787	594,826

The year-over-year change in the number of shares issued primarily reflects an increased number of shares issued under our 1998 Long-Term Incentive Plan due to the exercise of stock options during the current year. This increase was partially offset by the fact that we are purchasing shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During the current period, we repurchased 124,185 shares attributable to equity awards and repurchased and retired 375,468 shares attributable to our accelerated share repurchase agreement which are not included in the table above.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares, which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. As a result of this transaction, beginning in our fourth fiscal quarter of 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

As of March 31, 2011, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. As of March 31, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $906 million. These facilities are described in further detail in Note 5 to the unaudited condensed consolidated financial statements.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we will be able to issue a total of $950 million in debt securities and $350 million in equity securities. At March 31, 2011, no securities had been issued under the shelf registration statement.

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 regulated and nonregulated 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). As of March 31, 2011, S&P maintained a stable outlook, while Moody's and Fitch maintained their rating outlook as positive. On March 31, 2011, Moody's placed us under review for a possible upgrade. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa2	BBB+
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions or other events could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently 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 March 31, 2011. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2011, September 30, 2010 and March 31, 2010:

	March 31, 2011		September 30, 2010		March 31, 2010	
	(In thousands, except percentages)					
Short-term debt	$ —	—	$ 126,100	2.8%	$ —	—
Long-term debt	2,159,757	47.6%	2,169,682	48.5%	2,169,606	48.1%
Shareholders' equity	2,373,979	52.4%	2,178,348	48.7%	2,338,843	51.9%
Total	$4,533,736	100.0%	$4,474,130	100.0%	$4,508,449	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 47.6 percent at March 31, 2011, 51.3 percent at September 30, 2010 and 48.1 percent at March 31, 2010. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 8 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2011.

Risk Management Activities

We conduct risk management activities through our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases.

In our nonregulated 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and six months ended March 31, 2011 and 2010:

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
	(In thousands)			
Fair value of contracts at beginning of period	$ 26,806	$(17,470)	$ (49,600)	$(14,166)
Contracts realized/settled	(18,064)	(13,390)	(51,045)	(34,418)
Fair value of new contracts	540	(1,288)	1,071	(2,236)
Other changes in value	21,251	10,413	130,107	29,085
Fair value of contracts at end of period	$ 30,533	$(21,735)	$ 30,533	$(21,735)

The fair value of our natural gas distribution segment's financial instruments at March 31, 2011 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2011				
	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	$30,533	$—	$—	$—	$30,533
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$30,533	$—	$—	$—	$30,533

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and six months ended March 31, 2011 and 2010:

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
	(In thousands)			
Fair value of contracts at beginning of period	$(10,681)	$ 32,306	$(12,374)	$ 26,698
Contracts realized/settled	(1,009)	(22,030)	(75)	(24,242)
Fair value of new contracts	—	—	—	—
Other changes in value	(1,252)	3,951	(493)	11,771
Fair value of contracts at end of period	(12,942)	14,227	(12,942)	14,227
Netting of cash collateral	17,053	7,199	17,053	7,199
Cash collateral and fair value of contracts at period end	$ 4,111	$ 21,426	$ 4,111	$ 21,426

The fair value of our nonregulated segment's financial instruments at March 31, 2011 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2011				
	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	$(9,121)	$(3,851)	$30	$—	$(12,942)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(9,121)	$(3,851)	$30	$—	$(12,942)

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2011 and 2010, our total net periodic pension and other benefits costs were $28.8 million and $25.4 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2011 costs were determined using a September 30, 2010 measurement date. As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. We maintained the expected return on our pension plan assets at

8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Accordingly, our fiscal 2011 pension and postretirement medical costs for the six months ended March 31, 2011 were significantly higher than the prior-year period.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the election period, a limited number of participants chose to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. An immaterial curtailment gain was recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we expect we will be required to contribute less than $2 million to our pension plans by September 15, 2011. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $11 million to these plans during fiscal 2011.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three and six month periods ended March 31, 2011 and 2010.

Natural Gas Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
METERS IN SERVICE, end of period				
Residential	2,930,594	2,937,163	2,930,594	2,937,163
Commercial	269,537	272,925	269,537	272,925
Industrial	2,384	2,496	2,384	2,496
Public authority and other	10,516	9,461	10,516	9,461
Total meters	3,213,031	3,222,045	3,213,031	3,222,045
INVENTORY STORAGE BALANCE — Bcf	30.1	24.4	30.1	24.4
SALES VOLUMES — MMcf[(1)]				
Gas sales volumes				
Residential	85,707	100,858	137,531	161,404
Commercial	40,879	46,615	67,773	77,105
Industrial	6,148	6,660	11,402	11,979
Public authority and other	4,104	4,397	6,922	7,356
Total gas sales volumes	136,838	158,530	223,628	257,844
Transportation volumes	40,656	40,545	75,409	76,786
Total throughput	177,494	199,075	299,037	334,630
OPERATING REVENUES (000's)[(1)]				
Gas sales revenues				
Residential	$ 725,904	$ 897,249	$1,184,585	$1,405,160
Commercial	296,280	366,260	492,343	585,680
Industrial	35,187	41,777	64,638	72,810
Public authority and other	27,631	32,386	46,261	52,584
Total gas sales revenues	1,085,002	1,337,672	1,787,827	2,116,234
Transportation revenues	18,879	18,219	35,462	34,694
Other gas revenues	9,323	10,097	17,110	17,954
Total operating revenues	$1,113,204	$1,365,988	$1,840,399	$2,168,882
Average transportation revenue per Mcf	$ 0.46	$ 0.45	$ 0.47	$ 0.45
Average cost of gas per Mcf sold	$ 5.28	$ 6.19	$ 5.14	$ 5.77

See footnote following these tables.

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2011	2010	2011	2010
CUSTOMERS, end of period				
Industrial	753	727	753	727
Municipal	62	62	62	62
Other	513	498	513	498
Total	1,328	1,287	1,328	1,287
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	23.3	21.3	23.3	21.3
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	174,471	192,441	327,649	350,214
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[(1)]	127,377	123,877	235,089	226,138
OPERATING REVENUES (000's)[(1)]				
Regulated transmission and storage	$ 54,976	$ 55,181	$ 103,983	$ 102,041
Nonregulated	583,531	677,032	1,059,171	1,225,048
Total operating revenues	$638,507	$732,213	$1,163,154	$1,327,089

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the six months ended March 31, 2011, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of March 31, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the six months ended March 31, 2011, except as noted in Note 8 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. ***Exhibits***

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

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: May 5, 2011

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
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*	
101.INS	XBRL Instance Document**	
101.SCH	XBRL Taxonomy Extension Schema**	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase**	
101.LAB	XBRL Taxonomy Extension Labels Linkbase**	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase**	

* 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.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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, 2011

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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 29, 2011.

Class	Shares Outstanding
No Par Value	90,285,306

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2011	September 30, 2010
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,599,950	$6,542,318
Less accumulated depreciation and amortization	1,683,899	1,749,243
Net property, plant and equipment	4,916,051	4,793,075
Current assets		
Cash and cash equivalents	117,429	131,952
Accounts receivable, net	342,092	273,207
Gas stored underground	256,768	319,038
Other current assets	273,459	150,995
Total current assets	989,748	875,192
Goodwill and intangible assets	739,677	740,148
Deferred charges and other assets	347,994	355,376
	$6,993,470	$6,763,791
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, 2011 — 90,284,722 shares; September 30, 2010 — 90,164,103 shares	$ 451	$ 451
Additional paid-in capital	1,730,121	1,714,364
Retained earnings	599,506	486,905
Accumulated other comprehensive income (loss)	5,746	(23,372)
Shareholders' equity	2,335,824	2,178,348
Long-term debt	2,206,106	1,809,551
Total capitalization	4,541,930	3,987,899
Current liabilities		
Accounts payable and accrued liabilities	312,205	266,208
Other current liabilities	333,643	413,640
Short-term debt	—	126,100
Current maturities of long-term debt	2,434	360,131
Total current liabilities	648,282	1,166,079
Deferred income taxes	967,607	829,128
Regulatory cost of removal obligation	396,201	350,521
Deferred credits and other liabilities	439,450	430,164
	$6,993,470	$6,763,791

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2011	2010
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 407,031	$ 396,319
Regulated transmission and storage segment	53,570	44,957
Nonregulated segment	491,285	427,405
Intersegment eliminations	(108,271)	(107,376)
	843,615	761,305
Purchased gas cost		
Natural gas distribution segment	206,839	204,988
Regulated transmission and storage segment	—	—
Nonregulated segment	477,880	415,634
Intersegment eliminations	(107,909)	(106,983)
	576,810	513,639
Gross profit	266,805	247,666
Operating expenses		
Operation and maintenance	112,665	111,559
Depreciation and amortization	56,932	51,940
Taxes, other than income	52,142	51,908
Asset impairments	10,988	—
Total operating expenses	232,727	215,407
Operating income	34,078	32,259
Miscellaneous expense	(1,430)	(798)
Interest charges	35,845	37,267
Loss from continuing operations before income taxes	(3,197)	(5,806)
Income tax benefit	(1,723)	(1,577)
Loss from continuing operations	(1,474)	(4,229)
Income from discontinued operations, net of tax ($590 and $700)	908	1,075
Net loss	$ (566)	$ (3,154)
Basic earning per share		
Loss per share from continuing operations	$ (0.02)	$ (0.04)
Income per share from discontinued operations	0.01	0.01
Net loss per share — basic	$ (0.01)	$ (0.03)
Diluted earnings per share		
Loss per share from continuing operations	$ (0.02)	$ (0.04)
Income per share from discontinued operations	0.01	0.01
Net loss per share — diluted	$ (0.01)	$ (0.03)
Cash dividends per share	$ 0.34	$ 0.335
Weighted average shares outstanding:		
Basic	90,127	92,648
Diluted	90,127	92,648

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2011	2010
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,187,907	$2,512,032
Regulated transmission and storage segment	157,553	146,998
Nonregulated segment	1,550,456	1,652,453
Intersegment eliminations	(337,542)	(370,229)
	3,558,374	3,941,254
Purchased gas cost		
Natural gas distribution segment	1,317,775	1,657,412
Regulated transmission and storage segment	—	—
Nonregulated segment	1,491,815	1,556,746
Intersegment eliminations	(336,413)	(369,017)
	2,473,177	2,845,141
Gross profit	1,085,197	1,096,113
Operating expenses		
Operation and maintenance	341,317	348,458
Depreciation and amortization	167,176	156,201
Taxes, other than income	145,868	152,840
Asset impairments	30,270	—
Total operating expenses	684,631	657,499
Operating income	400,566	438,614
Miscellaneous income (expense)	24,046	(905)
Interest charges	112,615	115,481
Income from continuing operations before income taxes	311,997	322,228
Income tax expense	114,211	124,199
Income from continuing operations	197,786	198,029
Income from discontinued operations, net of tax ($5,122 and $4,094)	7,854	6,273
Net income	$ 205,640	$ 204,302
Basic earning per share		
Income per share from continuing operations	$ 2.17	$ 2.12
Income per share from discontinued operations	0.09	0.07
Net income per share — basic	$ 2.26	$ 2.19
Diluted earnings per share		
Income per share from continuing operations	$ 2.16	$ 2.11
Income per share from discontinued operations	0.09	0.07
Net income per share — diluted	$ 2.25	$ 2.18
Cash dividends per share	$ 1.02	$ 1.005
Weighted average shares outstanding:		
Basic	90,233	92,513
Diluted	90,530	92,856

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2011	2010
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 205,640	$ 204,302
Adjustments to reconcile net income to net cash provided by operating activities:		
Asset impairments	30,270	—
Depreciation and amortization:		
Charged to depreciation and amortization	171,726	160,207
Charged to other accounts	149	116
Deferred income taxes	115,488	186,325
Other	15,927	18,425
Net assets/liabilities from risk management activities	(15,869)	3,429
Net change in operating assets and liabilities	(3,769)	21,760
Net cash provided by operating activities	519,562	594,564
Cash Flows From Investing Activities		
Capital expenditures	(390,283)	(362,349)
Other, net	(3,373)	(438)
Net cash used in investing activities	(393,656)	(362,787)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(132,072)	(76,019)
Net proceeds from issuance of long-term debt	394,618	—
Settlement of Treasury lock agreements	20,079	—
Unwinding of Treasury lock agreements	27,803	—
Repayment of long-term debt	(360,066)	(66)
Cash dividends paid	(93,039)	(93,913)
Repurchase of equity awards	(5,300)	(1,173)
Issuance of common stock	7,548	8,574
Net cash used in financing activities	(140,429)	(162,597)
Net increase (decrease) in cash and cash equivalents	(14,523)	69,180
Cash and cash equivalents at beginning of period	131,952	111,203
Cash and cash equivalents at end of period	$ 117,429	$ 180,383

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2011

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which currently cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, we will operate in nine states. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc, (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

As discussed in Note 11, we operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2011 are not indicative of our results of operations for the full 2011 fiscal year, which ends September 30, 2011.

Our earnings have been impacted by several one-time items in the current year, including the following pre-tax amounts:

- $27.8 million gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $19.3 million non-cash impairment of assets in the Ft. Necessity storage project.
- $11.0 million non-cash impairment of certain natural gas gathering assets.
- $5.0 million one-time tax benefit related to the administrative settlement of various income tax positions.

We have evaluated subsequent events from the June 30, 2011 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010.

As a result of discontinued operations, certain prior-year amounts have been reclassified to conform with the current year presentation.

During the second quarter of fiscal 2011, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

During the nine months ended June 30, 2011, two new accounting standards became applicable to the Company pertaining to goodwill impairment testing for reporting units with zero or negative carrying amounts and disclosure of supplementary pro forma information for business combinations. The adoption of these standards had no impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the nine months ended June 30, 2011.

In May 2011, the Financial Accounting Standards Board (FASB) issued guidance that will provide a consistent definition of fair value and ensure that fair value measurements and disclosure requirements are similar between U.S. GAAP and International Financial Reporting Standards. This guidance will change certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements and is effective prospectively for the Company for interim and annual periods beginning after December 15, 2011. We currently do not have any recurring Level 3 fair value measurements; accordingly, the adoption of this guidance will not impact our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance related to the presentation of other comprehensive income which will require that all nonowner changes in shareholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In the two-statement approach, the first statement should present total net income and its components followed by a second statement that should present total other comprehensive income, the components of other comprehensive income, and the total of comprehensive income. This guidance is effective retrospectively for the Company for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of this guidance will not impact our financial position, results of operations or cash flows.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of June 30, 2011 and September 30, 2010 included the following:

	June 30, 2011	September 30, 2010
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$200,393	$209,564
Merger and integration costs, net	6,360	6,714
Deferred gas costs	22,083	22,701
Regulatory cost of removal asset	32,691	31,014
Environmental costs	434	805
Rate case costs	5,321	4,505
Deferred franchise fees	393	1,161
Other	3,940	1,046
	$271,615	$277,510
Regulatory liabilities:		
Deferred gas costs	$ 18,739	$ 43,333
Deferred franchise fees	629	—
Regulatory cost of removal obligation	429,354	381,474
Other	9,166	6,112
	$457,888	$430,919

The June 30, 2011 amounts above do not include regulatory assets and liabilities related to our Missouri, Illinois and Iowa service areas, which are classified as assets held for sale as discussed in Note 5.

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

Comprehensive income

The following table presents the components of comprehensive income (loss), net of related tax, for the three-month and nine-month periods ended June 30, 2011 and 2010:

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands)			
Net income (loss)	$ (566)	$(3,154)	$205,640	$204,302
Unrealized holding gains (losses) on investments, net of tax expense (benefit) of $(56) and $(996) for the three months ended June 30, 2011 and 2010 and of $876 and $(198) for the nine months ended June 30, 2011 and 2010	(94)	(1,696)	1,492	(337)
Amortization, unrealized gain and unwinding of interest rate hedging transactions, net of tax expense (benefit) of $(4,629) and $247 for the three months ended June 30, 2011 and 2010 and $7,950 and $743 for the nine month ended June 30, 2011 and 2010	(7,884)	422	13,536	1,265
Net unrealized gains (losses) on commodity hedging transactions, net of tax expense (benefit) of $(182) and $5,066 for the three months ended June 30, 2011 and 2010 and $9,008 and $2,999 for the nine months ended June 30, 2011 and 2010	(285)	7,921	14,090	4,690
Comprehensive income (loss)	$(8,829)	$ 3,493	$234,758	$209,920

Accumulated other comprehensive income (loss), net of tax, as of June 30, 2011 and September 30, 2010 consisted of the following unrealized gains (losses):

	June 30, 2011	September 30, 2010
	(In thousands)	
Accumulated other comprehensive income (loss):		
Unrealized holding gains on investments	$ 5,697	$ 4,205
Treasury lock agreements	8,068	(5,468)
Cash flow hedges	(8,019)	(22,109)
	$ 5,746	$(23,372)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the third quarter there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2010-2011 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 35 percent, or 31.7 Bcf of the planned winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver 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.

We also perform asset optimization activities in our nonregulated segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated segment is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Futures contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the obligation, to buy or sell the commodity at a fixed

price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 65 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order 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. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on June 30, 2011, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.1 Bcf.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $300 million of a total $400 million of senior notes that were issued in June 2011. This offering is discussed in Note 6. We designated these Treasury locks as cash flow hedges of an anticipated transaction. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges of an anticipated transaction. Due to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock

agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pre-tax cash gain of $27.8 million during the second quarter.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. These Treasury locks, as well as the Treasury locks discussed above, were settled at various times at a cumulative net loss. These realized gains and losses were recorded as a component of accumulated other comprehensive income (loss) and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of June 30, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(20,915)
	Cash Flow	—	28,317
	Not designated	16,340	18,140
		16,340	25,542

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of June 30, 2011 and September 30, 2010. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $15.4 million and $24.9 million of cash held on deposit in margin accounts as of June 30, 2011 and September 30, 2010 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below

will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
June 30, 2011				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 11,529	$ 11,529
Noncurrent commodity contracts	Deferred charges and other assets	—	241	241
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(15,930)	(15,930)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(6,237)	(6,237)
Total		—	(10,397)	(10,397)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	1,972	19,174	21,146
Noncurrent commodity contracts	Deferred charges and other assets	767	7,093	7,860
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(5,207)	(20,109)	(25,316)
Noncurrent commodity contracts	Deferred credits and other liabilities	(56)	(7,170)	(7,226)
Total		(2,524)	(1,012)	(3,536)
Total Financial Instruments		$(2,524)	$(11,409)	$(13,933)

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2010				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 40,030	$ 40,030
Noncurrent commodity contracts	Deferred charges and other assets	—	2,461	2,461
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(56,575)	(56,575)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(9,222)	(9,222)
Total		—	(23,306)	(23,306)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	2,219	16,459	18,678
Noncurrent commodity contracts	Deferred charges and other assets	47	2,056	2,103
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(48,942)	(7,178)	(56,120)
Noncurrent commodity contracts	Deferred credits and other liabilities	(2,924)	(405)	(3,329)
Total		(49,600)	10,932	(38,668)
Total Financial Instruments		$(49,600)	$(12,374)	$(61,974)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended June 30, 2011 and 2010 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $5.8 million and $3.8 million. For the nine months ended June 30, 2011 and 2010 we

recognized a gain arising from fair value and cash flow hedge ineffectiveness of $23.3 million and $44.2 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and nine months ended June 30, 2011 and 2010 is presented below.

	Three Months Ended June 30	
	2011	2010
	(In thousands)	
Commodity contracts	$ 7,837	$(10,525)
Fair value adjustment for natural gas inventory designated as the hedged item	(1,781)	14,678
Total impact on revenue	$ 6,056	$ 4,153
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ 853	$ (235)
Timing ineffectiveness	5,203	4,388
	$ 6,056	$ 4,153

	Nine Months Ended June 30	
	2011	2010
	(In thousands)	
Commodity contracts	$ 4,834	$20,296
Fair value adjustment for natural gas inventory designated as the hedged item	19,430	26,195
Total impact on revenue	$24,264	$46,491
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ 1,265	$ (684)
Timing ineffectiveness	22,999	47,175
	$24,264	$46,491

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2011 and 2010 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended June 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(3,907)	$(3,907)
Loss arising from ineffective portion of commodity contracts	—	—	(281)	(281)
Total impact on revenue	—	—	(4,188)	(4,188)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(614)	—	—	(614)
Total Impact from Cash Flow Hedges	$(614)	$ —	$(4,188)	$(4,802)

	Three Months Ended June 30, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(8,523)	$(8,523)
Loss arising from ineffective portion of commodity contracts	—	—	(350)	(350)
Total impact on revenue	—	—	(8,873)	(8,873)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(669)	—	—	(669)
Total Impact from Cash Flow Hedges	$(669)	$ —	$(8,873)	$(9,542)

	Nine Months Ended June 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(25,488)	$(25,488)
Loss arising from ineffective portion of commodity contracts	—	—	(958)	(958)
Total impact on revenue	—	—	(26,446)	(26,446)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(1,953)	—	—	(1,953)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total Impact from Cash Flow Hedges	$19,850	$6,000	$(26,446)	$ (596)

	Nine Months Ended June 30, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(40,196)	$(40,196)
Loss arising from ineffective portion of commodity contracts	—	—	(2,307)	(2,307)
Total impact on revenue	—	—	(42,503)	(42,503)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,008)	—	—	(2,008)
Total Impact from Cash Flow Hedges	$(2,008)	$ —	$(42,503)	$(44,511)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and nine months ended June 30, 2011 and 2010. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands)			
Increase (decrease) in fair value:				
Treasury lock agreements	$(8,270)	$ —	$ 29,822	$ —
Forward commodity contracts	(2,668)	2,722	(1,457)	(19,829)
Recognition of (gains) losses in earnings due to settlements:				
Treasury lock agreements	386	422	(16,286)	1,265
Forward commodity contracts	2,383	5,199	15,547	24,519
Total other comprehensive income (loss) from hedging, net of tax[1]	$(8,169)	$8,343	$ 27,626	$ 5,955

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2011.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,266)	$(3,905)	$(5,171)
Thereafter	9,334	(4,114)	5,220
Total[1]	$ 8,068	$(8,019)	$ 49

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended June 30, 2011 and 2010 was an increase (decrease) in revenue of $(4.3) million and $0.7 million. For the nine months ended June 30, 2011 and 2010 revenue increased $3.9 million and $13.0 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the three and nine months ended June 30, 2011, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 8 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2010.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2011 and

September 30, 2010. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	June 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,739	$ —	$ —	$ 2,739
Nonregulated segment	3,696	34,367	—	(25,006)	13,057
Total financial instruments	3,696	37,106	—	(25,006)	15,796
Hedged portion of gas stored underground	86,544	—	—	—	86,544
Available-for-sale securities	44,045	—	—	—	44,045
Total assets	$134,285	$37,106	$ —	$(25,006)	$146,385
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 5,263	$ —	$ —	$ 5,263
Nonregulated segment	10,645	38,827	—	(40,388)	9,084
Total liabilities	$ 10,645	$44,090	$ —	$(40,388)	$ 14,347

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,266	$ —	$ —	$ 2,266
Nonregulated segment	18,544	42,462	—	(41,760)	19,246
Total financial instruments	18,544	44,728	—	(41,760)	21,512
Hedged portion of gas stored underground	57,507	—	—	—	57,507
Available-for-sale securities	41,466	—	—	—	41,466
Total assets	$117,517	$44,728	$ —	$(41,760)	$120,485
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,866	$ —	$ —	$ 51,866
Nonregulated segment	41,430	31,950	—	(66,649)	6,731
Total liabilities	$ 41,430	$83,816	$ —	$(66,649)	$ 58,597

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are

adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of June 30, 2011, we had $15.4 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $4.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $11.0 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

Nonrecurring Fair Value Measurements

As discussed in Note 9, during the third quarter we performed an impairment assessment of certain natural gas gathering assets in our nonregulated segment. We used a combination of a market and income approach in a weighted average discounted cash flow analysis that included significant inputs such as our weighted average cost of capital and assumptions regarding future natural gas prices. This is a Level 3 fair value measurement because the inputs used are unobservable. Based on this analysis, we determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value of approximately $6 million and recorded a pre-tax noncash impairment loss of approximately $11 million.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of June 30, 2011:

	June 30, 2011
	(In thousands)
Carrying Amount	$2,212,630
Fair Value	$2,474,064

5. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for an all cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our condensed consolidated balance sheets at June 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands)			
Operating revenues	$11,524	$8,952	$71,047	$62,121
Purchased gas cost	5,460	3,390	44,993	39,836
Gross profit	6,064	5,562	26,054	22,285
Operating expenses	4,472	3,712	12,919	11,654
Operating income	1,592	1,850	13,135	10,631
Other nonoperating expense	(94)	(75)	(159)	(264)
Income from discontinued operations before income taxes	1,498	1,775	12,976	10,367
Income tax expense	590	700	5,122	4,094
Net income	$ 908	$1,075	$ 7,854	$ 6,273

The following table presents balance sheet data related to assets held for sale.

	June 30, 2011
	(In thousands)
Net plant, property & equipment	$126,375
Gas stored underground	5,938
Other current assets	431
Deferred charges and other assets	197
Assets held for sale	$132,941
Accounts payable and accrued liabilities	$ 1,808
Other current liabilities	5,086
Regulatory cost of removal obligation	11,435
Deferred credits and other liabilities	810
Liabilities held for sale	$ 19,139

6. Debt

Long-term debt

Long-term debt at June 30, 2011 and September 30, 2010 consisted of the following:

	June 30, 2011	September 30, 2010
	(In thousands)	
Unsecured 7.375% Senior Notes, redeemed May 2011	$ —	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	—
Medium term notes		
Series A, 1995-2, 6.27%, due December 2010	—	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term note due in installments through 2013	327	393
Total long-term debt	2,212,630	2,172,696
Less:		
Original issue discount on unsecured senior notes and debentures	(4,090)	(3,014)
Current maturities	(2,434)	(360,131)
	$2,206,106	$1,809,551

As noted above, our unsecured 10% notes will mature in December 2011; accordingly, these have been classified within the current maturities of long-term debt.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011, using funds drawn from commercial paper. We replaced these senior notes on June 10, 2011 with $400 million 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks discussed in Note 3. The majority of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

Prior to the third quarter of fiscal 2011, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. On April 13, 2011, our $200 million 180-day unsecured credit facility expired and was not replaced. On May 2, 2011, we replaced our $566.7 million unsecured credit facility with a new five-year $750 million unsecured credit

facility with an accordion feature that could increase our borrowing capacity to $1.0 billion. As a result of these changes, we have $975 million of working capital funding from our commercial paper program and three committed revolving credit facilities with third-party lenders.

At June 30, 2011, there were no short-term debt borrowings outstanding. At September 30, 2010, there was a total of $126.1 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and two committed revolving credit facilities with third-party lenders that provide approximately $775 million of working capital funding. The first facility is a five-year $750 million unsecured credit facility, expiring May 2016, that bears interest at a base rate or at a LIBOR- based rate for the applicable interest period, plus a spread ranging from zero percent to 2 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At June 30, 2011, there were no borrowings under this facility nor was there any commercial paper outstanding.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. This facility was renewed effective April 1, 2011. At June 30, 2011, there were no borrowings outstanding under this facility.

The availability of funds under these 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2011, our total-debt-to-total-capitalization ratio, as defined, was 51 percent. In addition, both the interest margin over the Eurodollar rate and the fees that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $350 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There was $173.8 million outstanding under this facility at June 30, 2011.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), a wholly-owned subsidiary of AEH has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate

equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At June 30, 2011, there were no borrowings outstanding under this credit facility. However, at June 30, 2011, AEM letters of credit totaling $24.8 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 $125.2 million at June 30, 2011.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At June 30, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.34 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at June 30, 2011, AEM's net working capital was $139.5 million and its tangible net worth was $150.9 million.

To supplement borrowings under this facility, AEH has a $350 million intercompany demand credit facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There were no borrowings outstanding under this facility at June 30, 2011.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities prior to our $400 million senior notes offering in June 2011. At June 30, 2011, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB+ and a Moody's rating of Baa1. We have no other 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.

We were in compliance with all of our debt covenants as of June 30, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and nine months ended June 30, 2011 and 2010 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands, except per share amounts)			
Basic Earnings Per Share from continuing operations				
Income (loss) from continuing operations	$ (1,474)	$ (4,229)	$197,786	$198,029
Less: Income (loss) from continuing operations allocated to participating securities	(32)	(51)	2,076	2,018
Income (loss) from continuing operations available to common shareholders	$ (1,442)	$ (4,178)	$195,710	$196,011
Basic weighted average shares outstanding	90,127	92,648	90,233	92,513
Income (loss) from continuing operations per share — Basic	$ (0.02)	$ (0.04)	$ 2.17	$ 2.12
Basic Earnings Per Share from discontinued operations				
Income from discontinued operations	$ 908	$ 1,075	$ 7,854	$ 6,273
Less: Income from discontinued operations allocated to participating securities	20	13	82	64
Income from discontinued operations available to common shareholders	$ 888	$ 1,062	$ 7,772	$ 6,209
Basic weighted average shares outstanding	90,127	92,648	90,233	92,513
Income from discontinued operations per share — Basic	$ 0.01	$ 0.01	$ 0.09	$ 0.07
Net income (loss) per share — Basic	$ (0.01)	$ (0.03)	$ 2.26	$ 2.19

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands, except per share amounts)			
Diluted Earnings Per Share from continuing operations				
Income (loss) from continuing operations available to common shareholders	$ (1,442)	$ (4,178)	$195,710	$196,011
Effect of dilutive stock options and other shares	—	—	4	4
Income (loss) from continuing operations available to common shareholders	$ (1,442)	$ (4,178)	$195,714	$196,015
Basic weighted average shares outstanding	90,127	92,648	90,233	92,513
Additional dilutive stock options and other shares	—	—	297	343
Diluted weighted average shares outstanding	90,127	92,648	90,530	92,856
Income (loss) from continuing operations per share — Diluted	$ (0.02)	$ (0.04)	$ 2.16	$ 2.11
Diluted Earnings Per Share from discontinued operations				
Income from discontinued operations available to common shareholders	$ 888	$ 1,062	$ 7,772	$ 6,209
Effect of dilutive stock options and other shares	2	—	—	—
Income from discontinued operations available to common shareholders	$ 890	$ 1,062	$ 7,772	$ 6,209
Basic weighted average shares outstanding	90,127	92,648	90,233	92,513
Additional dilutive stock options and other shares	—	—	297	343
Diluted weighted average shares outstanding	90,127	92,648	90,530	92,856
Income from discontinued operations per share — Diluted	$ 0.01	$ 0.01	$ 0.09	$ 0.07
Net income (loss) per share — Diluted	$ (0.01)	$ (0.03)	$ 2.25	$ 2.18

There were approximately 288,000 and 333,000 stock options and other shares excluded from the computation of diluted earnings per share for the three months ended June 30, 2011 and 2010 as their inclusion in the computation would be anti-dilutive.

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2011 and 2010 as their exercise price was less than the average market price of the common stock during that period.

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans. We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received and retired 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was

reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

8. 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, 2011 and 2010 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the election period, a limited number of participants chose to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. The curtailment gain was recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained unchanged.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,257	$ 3,993	$3,601	$3,360
Interest cost	7,055	6,524	3,204	3,018
Expected return on assets	(6,285)	(6,320)	(681)	(615)
Amortization of transition asset	—	—	377	377
Amortization of prior service cost	(106)	(193)	(362)	(375)
Amortization of actuarial loss	2,748	2,822	87	93
Net periodic pension cost	$ 7,669	$ 6,826	$6,226	$5,858

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 12,894	$ 11,982	$10,803	$10,077
Interest cost	21,034	19,569	9,610	9,051
Expected return on assets	(18,533)	(18,960)	(2,045)	(1,845)
Amortization of transition asset	—	—	1,133	1,134
Amortization of prior service cost	(323)	(582)	(1,087)	(1,125)
Amortization of actuarial loss	8,990	8,469	260	282
Curtailment gain	(40)	—	—	—
Net periodic pension cost	$ 24,022	$ 20,478	$18,674	$17,574

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2011 and 2010 are as follows:

	Pension Account Plan		Other Pension Benefits		Other Benefits	
	2011	2010	2011	2010	2011	2010
Discount rate	5.68%	5.52%	5.39%	5.52%	5.39%	5.52%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	8.25%	8.25%	5.00%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we will be required to contribute less than $2 million to our pension plans during fiscal 2011.

We contributed $8.7 million to our other post-retirement benefit plans during the nine months ended June 30, 2011. We expect to contribute a total of approximately $12 million to these plans during fiscal 2011.

For our Supplemental Executive Retirement Plans, we own equity securities that are classified as available-for-sale securities. These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of June 30, 2011:				
Domestic equity mutual funds	$27,593	$7,627	$ —	$35,220
Foreign equity mutual funds	4,597	1,416	—	6,013
Money market funds	2,812	—	—	2,812
	$35,002	$9,043	$ —	$44,045
As of September 30, 2010:				
Domestic equity mutual funds	$29,540	$5,698	$ —	$35,238
Foreign equity mutual funds	4,753	976	—	5,729
Money market funds	499	—	—	499
	$34,792	$6,674	$ —	$41,466

9. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 12 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30,

2010, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2011. We continue to believe that the final outcome of such litigation and environmental-related matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On March 30, 2011, we filed a notice of appeal of this ruling. We strongly believe that the trial court erred in not granting our motion to dismiss the lawsuit prior to trial and that the verdict is unsupported by law. After consultation with counsel, we believe that it is probable that any judgment based on this verdict will be overturned on appeal.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued does not reflect the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

In addition, we are involved in other litigation and environmental-related matters or claims that arise in the ordinary course of our business. While the ultimate results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we believe the final outcome of

such litigation and response actions will not have a material adverse effect on our financial condition, results of operations or cash flows.

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2011, AEH was committed to purchase 104.5 Bcf within one year, 52.4 Bcf within one to three years and 2.4 Bcf after three years under indexed contracts. AEH is committed to purchase 2.6 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $4.13 to $6.36 per Mcf. Purchases under these contracts totaled $356.8 million and $315.6 million for the three months ended June 30, 2011 and 2010 and $1,130.0 million and $1,208.4 million for the nine months ended June 30, 2011 and 2010.

Our natural gas distribution divisions, except for our 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 and fixed prices. The estimated commitments under these contracts as of June 30, 2011 are as follows (in thousands):

2011	$ 52,703
2012	307,694
2013	112,319
2014	86,994
2015	—
Thereafter	—
	$559,710

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2011.

Regulatory Matters

As previously described in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. There have been no material developments in this matter during the nine months ended June 30, 2011. We have accrued what we believe is an adequate amount for the anticipated resolution of this proceeding. While the ultimate resolution of this investigation cannot be predicted with certainty, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and

operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities in our Mid-Tex Division have agreed to a program of installing 100,000 replacements during the next two years, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing 25,311 lines for a cost of $34.0 million as of June 30, 2011. The program is progressing on schedule for completion in September 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

As of June 30, 2011, administrative reviews of our rate review mechanisms in our Mid-Tex and West Texas service areas were in progress and a gas reliability infrastructure program (GRIP) filing was in progress in our Atmos Pipeline — Texas service area. In addition, there were other ratemaking activities in progress in our Kentucky/Mid-States, West Texas and Louisiana service areas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments* and *Regulated Transmission and Storage Segment.*

Other Matters

AGC owns and operates the Park City and Shrewsbury gathering systems in Kentucky. The Park City gathering system consists of a 23-mile low pressure pipeline and a nitrogen removal unit that was constructed in 2008. The Shrewsbury production, gathering and processing assets were acquired in 2008 at which time we sold the production assets to a third party. As a result of the sale of the production assets, we obtained a 10-year production payment note under which we are to be paid from future production generated from the assets.

As noted above, AGC is involved in an ongoing lawsuit with the Park City gathering system. Due to the lawsuit and a low natural gas price environment, the assets have generated operating losses. As a result of these developments, we performed an impairment assessment of these assets during the third fiscal quarter and determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value based on the results of a weighted average discounted cash flow analysis and recorded a pretax noncash impairment loss of $11.0 million.

As we previously discussed in Note 9 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pretax noncash impairment loss to write off substantially all of our investment in the project.

10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 14 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the nine months ended June 30, 2011, there were no material changes in our concentration of credit risk.

11. Segment Information

Through November 30, 2010, our operations were divided into four segments:

- The *natural gas distribution segment*, which included our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which included the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which included a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which included our nonregulated natural gas gathering transmission and storage services.

As a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- The *natural gas distribution segment*, remains unchanged and includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, remains unchanged and includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services which were previously reported in the natural gas marketing and pipeline, storage and other segments.

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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2010. 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, 2011 and 2010 by segment are presented in the following tables. Prior-year amounts have been restated to reflect the new operating segments.

	Three Months Ended June 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$406,817	$19,772	$417,026	$ —	$843,615
Intersegment revenues	214	33,798	74,259	(108,271)	—
	407,031	53,570	491,285	(108,271)	843,615
Purchased gas cost	206,839	—	477,880	(107,909)	576,810
Gross profit	200,192	53,570	13,405	(362)	266,805
Operating expenses					
Operation and maintenance	86,804	18,786	7,437	(362)	112,665
Depreciation and amortization	49,099	6,790	1,043	—	56,932
Taxes, other than income	47,534	3,729	879	—	52,142
Asset impairments	—	—	10,988	—	10,988
Total operating expenses	183,437	29,305	20,347	(362)	232,727
Operating income (loss)	16,755	24,265	(6,942)	—	34,078
Miscellaneous income (expense)	(1,153)	(312)	168	(133)	(1,430)
Interest charges	28,042	7,653	283	(133)	35,845
Income (loss) from continuing operations before income taxes	(12,440)	16,300	(7,057)	—	(3,197)
Income tax expense (benefit)	(4,311)	5,748	(3,160)	—	(1,723)
Income (loss) from continuing operations	(8,129)	10,552	(3,897)	—	(1,474)
Income from discontinued operations, net of tax	908	—	—	—	908
Net income (loss)	$ (7,221)	$10,552	$ (3,897)	$ —	$ (566)
Capital expenditures	$121,452	$20,239	$ 1,929	$ —	$143,620

	Three Months Ended June 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$396,097	$22,796	$342,412	$ —	$761,305
Intersegment revenues	222	22,161	84,993	(107,376)	—
	396,319	44,957	427,405	(107,376)	761,305
Purchased gas cost	204,988	—	415,634	(106,983)	513,639
Gross profit	191,331	44,957	11,771	(393)	247,666
Operating expenses					
Operation and maintenance	87,323	16,050	8,579	(393)	111,559
Depreciation and amortization	45,633	5,171	1,136	—	51,940
Taxes, other than income	47,946	3,010	952	—	51,908
Total operating expenses	180,902	24,231	10,667	(393)	215,407
Operating income	10,429	20,726	1,104	—	32,259
Miscellaneous income (expense)	(72)	94	511	(1,331)	(798)
Interest charges	29,019	7,667	1,912	(1,331)	37,267
Income (loss) from continuing operations before income taxes	(18,662)	13,153	(297)	—	(5,806)
Income tax expense (benefit)	(6,685)	4,688	420	—	(1,577)
Income (loss) from continuing operations	(11,977)	8,465	(717)	—	(4,229)
Income from discontinued operations, net of tax	1,075	—	—	—	1,075
Net income (loss)	$ (10,902)	$ 8,465	$ (717)	$ —	$ (3,154)
Capital expenditures	$106,394	$22,964	$ 362	$ —	$129,720

	Nine Months Ended June 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,187,256	$ 62,602	$1,308,516	$ —	$3,558,374
Intersegment revenues	651	94,951	241,940	(337,542)	—
	2,187,907	157,553	1,550,456	(337,542)	3,558,374
Purchased gas cost	1,317,775	—	1,491,815	(336,413)	2,473,177
Gross profit	870,132	157,553	58,641	(1,129)	1,085,197
Operating expenses					
Operation and maintenance	268,299	49,591	24,556	(1,129)	341,317
Depreciation and amortization	145,548	18,387	3,241	—	167,176
Taxes, other than income	132,070	11,395	2,403	—	145,868
Asset impairments	—	—	30,270	—	30,270
Total operating expenses	545,917	79,373	60,470	(1,129)	684,631
Operating income (loss)	324,215	78,180	(1,829)	—	400,566
Miscellaneous income	18,305	5,267	764	(290)	24,046
Interest charges	87,344	23,802	1,759	(290)	112,615
Income (loss) from continuing operations before income taxes	255,176	59,645	(2,824)	—	311,997
Income tax expense (benefit)	94,323	21,252	(1,364)	—	114,211
Income (loss) from continuing operations	160,853	38,393	(1,460)	—	197,786
Income from discontinued operations, net of tax	7,854	—	—	—	7,854
Net income (loss)	$ 168,707	$ 38,393	$ (1,460)	$ —	$ 205,640
Capital expenditures	$ 340,713	$ 44,796	$ 4,774	$ —	$ 390,283

	Nine Months Ended June 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,511,350	$ 64,281	$1,365,623	$ —	$3,941,254
Intersegment revenues	682	82,717	286,830	(370,229)	—
	2,512,032	146,998	1,652,453	(370,229)	3,941,254
Purchased gas cost	1,657,412	—	1,556,746	(369,017)	2,845,141
Gross profit	854,620	146,998	95,707	(1,212)	1,096,113
Operating expenses					
Operation and maintenance	266,847	53,877	28,946	(1,212)	348,458
Depreciation and amortization	137,580	15,395	3,226	—	156,201
Taxes, other than income	140,234	9,226	3,380	—	152,840
Total operating expenses	544,661	78,498	35,552	(1,212)	657,499
Operating income	309,959	68,500	60,155	—	438,614
Miscellaneous income (expense)	1,474	117	1,524	(4,020)	(905)
Interest charges	87,877	23,589	8,035	(4,020)	115,481
Income from continuing operations before income taxes	223,556	45,028	53,644	—	322,228
Income tax expense	86,552	16,039	21,608	—	124,199
Income from continuing operations	137,004	28,989	32,036	—	198,029
Income from discontinued operations, net of tax	6,273	—	—	—	6,273
Net income	$ 143,277	$ 28,989	$ 32,036	$ —	$ 204,302
Capital expenditures	$ 302,621	$ 56,786	$ 2,942	$ —	$ 362,349

Balance sheet information at June 30, 2011 and September 30, 2010 by segment is presented to reflect our business structure as of June 30, 2011 in the following tables. Prior-year amounts have been restated accordingly.

	June 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,085,081	$771,777	$ 59,193	$ —	$4,916,051
Investment in subsidiaries	671,885	—	(2,096)	(669,789)	—
Current assets					
Cash and cash equivalents	39,446	—	77,983	—	117,429
Assets from risk management activities	1,972	—	13,041	—	15,013
Other current assets	565,265	15,822	469,576	(193,357)	857,306
Intercompany receivables	505,709	—	—	(505,709)	—
Total current assets	1,112,392	15,822	560,600	(699,066)	989,748
Intangible assets	—	—	363	—	363
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	767	—	16	—	783
Deferred charges and other assets	319,019	16,137	12,055	—	347,211
	$6,761,406	$936,077	$664,842	$(1,368,855)	$6,993,470
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,335,824	$251,080	$420,805	$ (671,885)	$2,335,824
Long-term debt	2,205,910	—	196	—	2,206,106
Total capitalization	4,541,734	251,080	421,001	(671,885)	4,541,930
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	173,845	—	—	(173,845)	—
Liabilities from risk management activities	5,207	—	2,995	—	8,202
Other current liabilities	419,848	8,862	226,352	(17,416)	637,646
Intercompany payables	—	503,857	1,852	(505,709)	—
Total current liabilities	601,203	512,719	231,330	(696,970)	648,282
Deferred income taxes	798,433	163,540	5,634	—	967,607
Noncurrent liabilities from risk management activities	56	—	6,089	—	6,145
Regulatory cost of removal obligation	396,201	—	—	—	396,201
Deferred credits and other liabilities	423,779	8,738	788	—	433,305
	$6,761,406	$936,077	$664,842	$(1,368,855)	$6,993,470

	September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$3,959,112	$748,947	$ 85,016	$ —	$4,793,075
Investment in subsidiaries	620,863	—	(2,096)	(618,767)	—
Current assets					
Cash and cash equivalents	31,952	—	100,000	—	131,952
Assets from risk management activities	2,219	—	18,356	—	20,575
Other current assets	528,655	19,504	325,348	(150,842)	722,665
Intercompany receivables	546,313	—	—	(546,313)	—
Total current assets	1,109,139	19,504	443,704	(697,155)	875,192
Intangible assets	—	—	834	—	834
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	47	—	890	—	937
Deferred charges and other assets	324,707	13,037	16,695	—	354,439
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,178,348	$212,687	$408,176	$ (620,863)	$2,178,348
Long-term debt	1,809,289	—	262	—	1,809,551
Total capitalization	3,987,637	212,687	408,438	(620,863)	3,987,899
Current liabilities					
Current maturities of long-term debt	360,000	—	131	—	360,131
Short-term debt	258,488	—	—	(132,388)	126,100
Liabilities from risk management activities	48,942	—	731	—	49,673
Other current liabilities	473,076	10,949	162,508	(16,358)	630,175
Intercompany payables	—	543,007	3,306	(546,313)	—
Total current liabilities	1,140,506	553,956	166,676	(695,059)	1,166,079
Deferred income taxes	691,126	142,337	(4,335)	—	829,128
Noncurrent liabilities from risk management activities	2,924	—	6,000	—	8,924
Regulatory cost of removal obligation	350,521	—	—	—	350,521
Deferred credits and other liabilities	413,416	4,849	2,975	—	421,240
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation as of June 30, 2011, the related condensed consolidated statements of income for the three-month and nine-month periods ended June 30, 2011 and 2010, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2011 and 2010. 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, 2010, 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 12, 2010, 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, 2010, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Ernst & Young LLP

Dallas, Texas
August 4, 2011

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, 2010.

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

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

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas currently located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, we will operate in nine states.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast and natural gas transportation and storage services to certain of our natural gas

distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 11, we operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

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, the 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 fiscal year ended September 30, 2010 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the nine months ended June 30, 2011.

RESULTS OF OPERATIONS

Due to the seasonality of our distribution business, we typically incur a net loss in our fiscal third quarter. For the three months ended June 30, 2011, we reported a net loss of $0.6 million, or $0.01 per diluted share compared to a net loss of $3.2 million, or $0.03 per diluted share in the prior-year quarter. The net loss for the three months ended June 30, 2011 includes noncash, unrealized net gains of $0.1 million, or $0.00 per diluted share compared with net losses of $11.1 million, or $0.12 per diluted share for the three months ended June 30, 2010. The net loss for the third quarter includes the impact of the non-cash impairment charge related to Atmos Gathering System assets, totaling $6.1 million or $0.06 per diluted share.

Excluding the impact of unrealized margins and one-time items, diluted earnings per share decreased from income of $0.09 per diluted share in the prior-year quarter to income of $0.05 per diluted share in the current-year quarter, primarily due a decrease in asset optimization margins in our nonregulated segment,

partially offset by rate increases in our natural gas distribution and regulated transmission and storage segments.

During the current quarter, we announced the sale of our natural gas distribution operations in our Missouri, Illinois and Iowa service areas. Due to the pending sales transaction, the results of operations for these three service areas are shown in discontinued operations. During the current-year quarter, discontinued operations generated net income of $0.9 million, or $0.01 per diluted share, compared with net income of $1.1 million, or $0.01 per diluted share in the prior-year quarter. Continuing operations in the current quarter generated a net loss of $1.5 million or $0.02 per diluted share, compared with a net loss of $4.2 million or $0.04 per diluted share from continuing operations in the prior-year quarter.

We reported net income of $205.6 million, or $2.25 per diluted share for the nine months ended June 30, 2011, compared with net income of $204.3 million or $2.18 per diluted share in the prior-year period. Income from continuing operations was $197.8 million, or $2.16 per diluted share compared with $198.0 million, or $2.11 per diluted share in the prior-year period. Income from discontinued operations was $7.9 million or $0.09 per diluted share for the year-to-date period, compared with $6.3 million or $0.07 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current period reduced net income by $1.4 million or $0.02 per diluted share compared with net losses recorded in the prior-year period of $6.2 million, or $0.07 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In the prior year-to-date period, net income included the net positive impact of a state sales tax refund of $4.5 million, or $0.05 per diluted share. In the current year-to-date period, net income includes the net positive impact of several one-time items totaling $6.5 million, or $0.07 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $30.3 million unfavorable impact related to the non-cash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

On June 10, 2011 we issued $400 million of 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to the settlement of the $300 million Treasury locks associated with the offering. The majority of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

During the nine months ended June 30, 2011, we executed on our strategy to streamline our credit facilities, as follows.

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and certain regulatory restrictions; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.
- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

After giving effect to these changes, we now have $975 million of liquidity available to us from our commercial paper program and three committed credit facilities and have reduced our financing costs. We believe this availability provides sufficient liquidity to fund our working capital needs.

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2011 and 2010:

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands, except per share data)			
Operating revenues	$843,615	$761,305	$3,558,374	$3,941,254
Gross profit	266,805	247,666	1,085,197	1,096,113
Operating expenses	232,727	215,407	684,631	657,499
Operating income	34,078	32,259	400,566	438,614
Miscellaneous income (expense)	(1,430)	(798)	24,046	(905)
Interest charges	35,845	37,267	112,615	115,481
Income (loss) from continuing operations before income taxes	(3,197)	(5,806)	311,997	322,228
Income tax expense (benefit)	(1,723)	(1,577)	114,211	124,199
Income (loss) from continuing operations	(1,474)	(4,229)	197,786	198,029
Income (loss) from discontinued operations, net of tax	908	1,075	7,854	6,273
Net income (loss)	$ (566)	$ (3,154)	$ 205,640	$ 204,302
Diluted net income (loss) per share from continuing operations	$ (0.02)	$ (0.04)	$ 2.16	$ 2.11
Diluted net income per share from discontinued operations	0.01	0.01	0.09	0.07
Diluted net income (loss) per share	$ (0.01)	$ (0.03)	$ 2.25	$ 2.18

The following tables segregate our consolidated net income (loss) and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended June 30		
	2011	2010	Change
	(In thousands, except per share data)		
Regulated operations	$ 2,423	$(3,512)	$ 5,935
Nonregulated operations	(3,897)	(717)	(3,180)
Net loss from continuing operations	(1,474)	(4,229)	2,755
Net income from discontinued operations	908	1,075	(167)
Net loss	$ (566)	$(3,154)	$ 2,588
Diluted EPS from continuing regulated operations	$ 0.02	$ (0.03)	$ 0.05
Diluted EPS from nonregulated operations	(0.04)	(0.01)	(0.03)
Diluted EPS from continuing operations	(0.02)	(0.04)	0.02
Diluted EPS from discontinued operations	0.01	0.01	—
Consolidated diluted EPS	$ (0.01)	$ (0.03)	$ 0.02

	Nine Months Ended June 30		
	2011	2010	Change
	(In thousands, except per share data)		
Regulated operations	$199,246	$165,993	$ 33,253
Nonregulated operations	(1,460)	32,036	(33,496)
Net income from continuing operations	197,786	198,029	(243)
Net income from discontinued operations	7,854	6,273	1,581
Net income	$205,640	$204,302	$ 1,338
Diluted EPS from continuing regulated operations	$ 2.18	$ 1.77	$ 0.41
Diluted EPS from nonregulated operations	(0.02)	0.34	(0.36)
Diluted EPS from continuing operations	2.16	2.11	0.05
Diluted EPS from discontinued operations	0.09	0.07	0.02
Consolidated diluted EPS	$ 2.25	$ 2.18	$ 0.07

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
Virginia	January — December

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately

reported in the following tables and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Three Months Ended June 30, 2011 compared with Three Months Ended June 30, 2010

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2011 and 2010 are presented below.

	Three Months Ended June 30		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Gross profit	$200,192	$191,331	$ 8,861
Operating expenses	183,437	180,902	2,535
Operating income	16,755	10,429	6,326
Miscellaneous expense	(1,153)	(72)	(1,081)
Interest charges	28,042	29,019	(977)
Loss from continuing operations before income taxes	(12,440)	(18,662)	6,222
Income tax benefit	(4,311)	(6,685)	2,374
Loss from continuing operations	(8,129)	(11,977)	3,848
Income from discontinued operations, net of tax	908	1,075	(167)
Net loss	$ (7,221)	$ (10,902)	$ 3,681
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	37,011	35,613	1,398
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	29,955	27,956	1,999
Consolidated natural gas distribution throughput from continuing operations — MMcf	66,966	63,569	3,397
Consolidated natural gas distribution throughput from discontinued operations — MMcf	2,128	2,359	(231)
Total consolidated natural gas distribution throughput — MMcf	69,094	65,928	3,166
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.46	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.59	$ 5.73	$ (0.14)

The following table shows our operating income (loss) from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended June 30, 2011 and 2010. The presentation of our natural gas distribution operating income (loss) is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30		
	2011	2010	Change
	(In thousands)		
Mid-Tex	$ 759	$ (2,179)	$ 2,938
Kentucky/Mid-States	4,832	3,344	1,488
Louisiana	6,779	6,537	242
West Texas	605	(104)	709
Colorado-Kansas	3,304	1,623	1,681
Mississippi	(615)	950	(1,565)
Other	1,091	258	833
Total	$16,755	$10,429	$ 6,326

The $8.9 million increase in natural gas distribution gross profit was primarily due to the following:

- $7.5 million net increase in rate adjustments, primarily in the Mid-Tex, Kentucky and Kansas service areas.
- $1.2 million increase in consolidated throughput due to a five percent increase in consolidated distribution throughput, primarily from higher consumption.
- $1.5 million decrease due to lower revenue-related taxes, offset by a decrease in taxes, other than income.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $2.5 million due primarily to a $3.5 million increase in depreciation and amortization expense, partially offset by $1.4 million lower employee expenses.

Nine Months Ended June 30, 2011 compared with Nine Months Ended June 30, 2010

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2011 and 2010 are presented below.

	Nine Months Ended June 30		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Gross profit	$870,132	$854,620	$ 15,512
Operating expenses	545,917	544,661	1,256
Operating income	324,215	309,959	14,256
Miscellaneous income	18,305	1,474	16,831
Interest charges	87,344	87,877	(533)
Income from continuing operations before income taxes	255,176	223,556	31,620
Income tax expense	94,323	86,552	7,771
Income from continuing operations	160,853	137,004	23,849
Income from discontinued operations, net of tax	7,854	6,273	1,581
Net income	$168,707	$143,277	$ 25,430
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	253,665	285,996	(32,331)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	99,551	98,442	1,109
Consolidated natural gas distribution throughput from continuing operations — MMcf	353,216	384,438	(31,222)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	12,723	13,835	(1,112)
Total consolidated natural gas distribution throughput — MMcf	365,939	398,273	(32,334)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.46	$ 0.01
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.21	$ 5.77	$ (0.56)

The following table shows our operating income from continuing operations by natural gas distribution division, in order of rate base, for the nine months ended June 30, 2011 and 2010. The presentation of our

natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2011	2010	Change
		(In thousands)	
Mid-Tex	$140,674	$128,045	$12,629
Kentucky/Mid-States	50,522	43,791	6,731
Louisiana	44,975	42,775	2,200
West Texas	29,405	33,053	(3,648)
Colorado-Kansas	26,256	24,071	2,185
Mississippi	27,604	28,604	(1,000)
Other	4,779	9,620	(4,841)
Total	$324,215	$309,959	$14,256

The $15.5 million increase in natural gas distribution gross profit primarily reflects a $35.8 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Kentucky, Kansas and Georgia service areas.

These increases were partially offset by:

- $11.2 million decrease due to an eight percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather this fiscal year compared to the same period last year in most of our service areas.

- $8.5 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $1.3 million, primarily due to the following:

- $7.4 million increase due to the absence of a state sales tax refund received in the prior year.

- $8.0 million increase in depreciation and amortization expense.

- $1.2 million increase in vehicles and equipment expense.

These increases were partially offset by:

- $8.2 million decrease in taxes, other than income, due to lower revenue-related taxes.

- $6.8 million decrease in employee-related expenses.

Net income for this segment for the year-to-date period was also favorably impacted by a $21.8 million gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the nine months ended June 30, 2011 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling.

Annual net operating income increases totaling $28.1 million resulting from ratemaking activity became effective in the nine months ended June 30, 2011 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
GRIP filings	$ 919
Annual rate filing mechanisms	25,070
Other rate activity	2,075
	$28,064

Additionally, the following ratemaking efforts were in progress during the third quarter of fiscal 2011 but had not been completed as of June 30, 2011.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	PRP[1]	Georgia	$ 1,192
Louisiana	LGS RSC[2]	Louisiana	4,600
Mid-Tex	Rate Review Mechanism (RRM)[3]	Settled Cities[4]	13,152
West Texas	Environs Rate Case[5]	Amarillo	78
	RRM	Lubbock	2,136
	RRM[6]	WT Cities	2,552
	Special Contract	Triangle	641
			$24,351

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) The Louisiana Commission Staff recommended an increase of $4.1 million effective July 1, 2011, which the Commission accepted.

(3) The amount requested represents an increase of $7.7 million under the RRM and $5.5 million related to year two of our steel service line program. In July 2011, the Company and representatives of the Settled Cities agreed to no change in operating income under the RRM and an operating income increase of $5.5 million related to the steel service line program to be implemented on September 1, 2011.

(4) Represents 439 of the 440 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.

(5) The Railroad Commission of Texas (RRC) approved the requested increase in operating income on July 26, 2011.

(6) On August 1, 2011, the Company and representatives of the West Texas Cities agreed to resolve the 2010 RRM with no change to operating income.

Rate Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. There were no rate cases completed within our natural gas distribution segment for the first three quarters of fiscal 2011.

GRIP Filings

The Gas Reliability Infrastructure Program (GRIP) in Texas allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. The following table summarizes our GRIP filings with effective dates during the nine months ended June 30, 2011.

Division	Calendar Year	Incremental Net Utility Plant Investment	Additional Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2011 GRIP:				
West Texas/Lubbock & WT Cities Environs	2010	$ 17,677	$343	06/01/2011
Mid-Tex/Environs	2010	107,840	576	06/27/2011
Total 2011 GRIP		$125,517	$919	

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms for the nine months ended June 30, 2011.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2009	$23,122	10/01/2010
Louisiana	TransLa	09/30/2010	350	04/01/2011
Mid-Tex	Dallas	12/31/2010	1,598	07/01/2011
Total 2011 Filings			$25,070	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2011:

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2011 Other Rate Activity:				
Kentucky/Mid-States	Georgia	PRP Surcharge	$ 764	10/01/2010
Colorado-Kansas	Colorado	AMI[(1)]	349	12/01/2010
Colorado-Kansas	Kansas	Ad Valorem[(2)]	685	01/01/2011
Kentucky/Mid-States	Missouri	ISRS[(3)]	277	02/14/2011
Total 2011 Other Rate Activity			$2,075	

(1) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of the Company's service area.

(2) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in the Company's base rates.

(3) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, 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.

Three Months Ended June 30, 2011 compared with Three Months Ended June 30, 2010

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2011 and 2010 are presented below.

	Three Months Ended June 30		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 32,098	$ 21,908	$10,190
Third-party transportation	16,518	17,521	(1,003)
Storage and park and lend services	1,802	2,646	(844)
Other	3,152	2,882	270
Gross profit	53,570	44,957	8,613
Operating expenses	29,305	24,231	5,074
Operating income	24,265	20,726	3,539
Miscellaneous income (expense)	(312)	94	(406)
Interest charges	7,653	7,667	(14)
Income before income taxes	16,300	13,153	3,147
Income tax expense	5,748	4,688	1,060
Net income	$ 10,552	$ 8,465	$ 2,087
Gross pipeline transportation volumes — MMcf	141,294	127,861	13,433
Consolidated pipeline transportation volumes — MMcf	112,564	100,770	11,794

On April 18, 2011, the Railroad Commission of Texas (RRC) issued an order in the rate case of Atmos Pipeline — Texas (APT) that was originally filed in September 2010. The RRC approved an annual operating

income increase of $20.4 million as well as the following major provisions that went into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity
- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- An annual adjustment mechanism, which was approved for a three-year pilot program, that will adjust regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly customer charges.

The $8.6 million increase in regulated transmission and storage gross profit was attributable primarily to a net $8.7 million increase as a result of this rate case.

Operating expenses increased $5.1 million primarily due to the following:

- $3.2 million due to higher levels of pipeline maintenance activities.
- $1.6 million due to higher depreciation expense.

At June 30, 2011, a GRIP filing was in progress with the RRC in which $12.6 million of additional annual operating income was requested. On July 26, 2011, the RRC approved the GRIP filing.

Nine Months Ended June 30, 2011 compared with Nine Months Ended June 30, 2010

Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2011 and 2010 are presented below.

	Nine Months Ended June 30		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 92,729	$ 81,833	$10,896
Third-party transportation	49,841	49,098	743
Storage and park and lend services	6,191	7,924	(1,733)
Other	8,792	8,143	649
Gross profit	157,553	146,998	10,555
Operating expenses	79,373	78,498	875
Operating income	78,180	68,500	9,680
Miscellaneous income	5,267	117	5,150
Interest charges	23,802	23,589	213
Income before income taxes	59,645	45,028	14,617
Income tax expense	21,252	16,039	5,213
Net income	$ 38,393	$ 28,989	$ 9,404
Gross pipeline transportation volumes — MMcf	468,943	478,075	(9,132)
Consolidated pipeline transportation volumes — MMcf	305,898	295,126	10,772

The $10.6 million increase in regulated transmission and storage gross profit was attributable primarily due to the following:

- $8.7 million net increase as a result of the rate case that was finalized and became effective in May 2011.
- $6.2 million increase associated with our GRIP filings.

These increases were partially offset by the following:

- $2.8 million decrease due to a decline in throughput to our Mid-Tex Division.
- $2.4 million decrease due to decreased transportation fees.

Operating expenses increased $0.9 million primarily due to the following:

- $3.0 million increase due to higher depreciation expense.
- $1.8 million increase due to higher ad valorem taxes.

These increases were partially offset by a $1.3 million decrease related to lower levels of pipeline maintenance activities.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas 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 financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEH continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEH may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market

conditions. If AEH elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to offset the original financial instruments. If AEH elects to defer the withdrawal of gas, it will execute new financial instruments to correspond to the revised withdrawal schedule and allow the original financial instrument to settle as contracted.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments 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 hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEH also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Three Months Ended June 30, 2011 compared with Three Months Ended June 30, 2010

Financial and operational highlights for our nonregulated segment for the three months ended June 30, 2011 and 2010 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the

unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	Three Months Ended June 30		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 11,631	$ 12,550	$ (919)
Storage and transportation services	4,042	3,319	723
Other	1,177	1,345	(168)
	16,850	17,214	(364)
Asset optimization[(1)]	(3,623)	9,303	(12,926)
Total realized margins	13,227	26,517	(13,290)
Unrealized margins	178	(14,746)	14,924
Gross profit	13,405	11,771	1,634
Operating expenses, excluding asset impairment	9,359	10,667	(1,308)
Asset impairment	10,988	—	10,988
Operating income (loss)	(6,942)	1,104	(8,046)
Miscellaneous income	168	511	(343)
Interest charges	283	1,912	(1,629)
Loss before income taxes	(7,057)	(297)	(6,760)
Income tax expense (benefit)	(3,160)	420	(3,580)
Net loss	$ (3,897)	$ (717)	$ (3,180)
Gross nonregulated delivered gas sales volumes — MMcf	104,658	91,854	12,804
Consolidated nonregulated delivered gas sales volumes — MMcf	88,382	75,014	13,368
Net physical position (Bcf)	16.7	20.1	(3.4)

(1) Net of storage fees of $3.8 million and $3.3 million.

Realized margins for gas delivery, storage and transportation services and other services were $16.9 million during the three months ended June 30, 2011 compared with $17.2 million for the prior-year quarter. The decrease primarily reflects a decrease of $0.03/Mcf for consolidated delivered gas margins in the current quarter, partially offset by an 18 percent increase in consolidated delivered gas volumes due to new customers in the power generation market.

The $12.9 million decrease in realized asset optimization margins from the prior-year quarter reflects the impact of continued weak natural gas market fundamentals, which have reduced price volatility and compressed spot to forward spread values resulting in less favorable trading opportunities. As a result, during the current quarter, AEH captured smaller spread values from its asset optimization activities. This contrasts to the prior-year quarter, when AEH recognized higher spread values that it had captured from rolling positions.

Weak market fundamentals have also reduced the demand and fees paid for storage. During the quarter, AEH started to capitalize on falling storage demand fees by replacing expiring storage contracts with new contracts with lower storage demand fees and allowing non-strategic contracts to expire without renewing them. This should improve AEH's ability to realize gains from its asset optimization activities in future periods.

The decrease in realized asset optimization margins was offset by a $14.9 million increase in unrealized margins that reflects the quarter-over-quarter timing of realized margins coupled with lower natural gas price volatility.

Operating expenses decreased $1.3 million primarily due to lower employee costs.

Asset impairment reflects the $11.0 million pre-tax impairment of certain natural gas gathering assets recorded in the current quarter.

Interest charges decreased $1.6 million primarily due to a decrease in intercompany borrowings.

Nine Months Ended June 30, 2011 compared with Nine Months Ended June 30, 2010

Financial and operational highlights for our natural gas marketing segment for the nine months ended June 30, 2011 and 2010 are presented below.

	Nine Months Ended June 30		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 46,842	$ 45,763	$ 1,079
Storage and transportation services	10,913	9,746	1,167
Other	3,956	3,907	49
	61,711	59,416	2,295
Asset optimization[(1)]	(344)	46,694	(47,038)
Total realized margins	61,367	106,110	(44,743)
Unrealized margins	(2,726)	(10,403)	7,677
Gross profit	58,641	95,707	(37,066)
Operating expenses, excluding asset impairment	30,200	35,552	(5,352)
Asset impairment	30,270	—	30,270
Operating income (loss)	(1,829)	60,155	(61,984)
Miscellaneous income	764	1,524	(760)
Interest charges	1,759	8,035	(6,276)
Income (loss) before income taxes	(2,824)	53,644	(56,468)
Income tax expense (benefit)	(1,364)	21,608	(22,972)
Net income (loss)	$ (1,460)	$ 32,036	$(33,496)
Gross nonregulated delivered gas sales volumes — MMcf	339,747	317,992	21,755
Consolidated nonregulated delivered gas sales volumes — MMcf	290,486	267,136	23,350
Net physical position (Bcf)	16.7	20.1	(3.4)

(1) Net of storage fees of $10.7 million and $10.0 million.

Realized margins for gas delivery, storage and transportation services and other services were $61.7 million during the nine months ended June 30, 2011 compared with $59.4 million for the prior-year period. The increase primarily reflects a nine percent increase in consolidated delivered gas sales volumes due to new customers in the power generation market and a $1.2 million increase in margins from storage and transportation services, attributable to new drilling projects in the Barnett Shale area.

The $47.0 million decrease in realized asset optimization margins from the prior-year period primarily reflects greater intramonth trading gains realized in the prior-year period from more favorable trading opportunities in the daily cash market, combined with lower realized gains in the current-year period due to continued weak natural gas market fundamentals.

Unrealized margins increased $7.7 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses decreased $5.4 million primarily due to lower employee expenses.

Asset impairment includes the aforementioned $11.0 million pre-tax impairment charge related to certain natural gas gathering assets. In addition, an asset impairment charge of $19.3 million was recorded in March 2011 related to our investment in Fort Necessity. As we previously discussed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, in February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. As such, we recorded a pretax noncash impairment to write off substantially all of our investment in the project during the second quarter of fiscal 2011.

Interest charges decreased $6.3 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEH monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEH's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEH's economic value and its potential gross profit (loss) at June 30, 2011 and 2010.

	June 30	
	2011	2010
	(In millions, unless otherwise noted)	
Economic value	$ (7.7)	$ (8.5)
Associated unrealized losses	8.3	16.5
Subtotal	0.6	8.0
Related fees[(1)]	(21.4)	(13.8)
Potential gross profit (loss)	$(20.8)	$ (5.8)
Net physical position (Bcf)	16.7	20.1

(1) Related fees represent the contractual costs to acquire the storage capacity utilized in our nonregulated segment's asset optimization activities. The fees primarily consist of demand fees and contractual obligations to sell gas below market index prices in exchange for the right to manage and optimize third party storage assets for the positions we have entered into as of June 30, 2011 and 2010.

During the nine months ended June 30, 2011, our nonregulated segment's economic value decreased from ($7.5) million, or ($0.48)/Mcf at September 30, 2010 to ($7.7) million, or ($0.46)/Mcf. This compares favorably to economic value at June 30, 2010 of ($8.5) million, or ($0.42)/Mcf.

For the nine months ended June 30, 2011, the decrease in our economic value was primarily the result of withdrawing physical gas below our overall weighted average cost of gas while settling financial instruments with higher average prices.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEH actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit calculated as of June 30, 2011 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. During fiscal 2011, we have been executing our strategy of consolidating our short-term facilities used for our regulated operations into a single line of credit, including the following.

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and certain

regulatory restrictions; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.

- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

As a result of these changes, we now have $975 million of availability from our commercial paper program and three committed revolving credit facilities with third parties.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011 using funds drawn from commercial paper. We refinanced this debt on a long-term basis through the issuance of $400 million 5.50% 30-year unsecured senior notes on June 10, 2011. On September 30, 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury lock and settlement. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks. The majority of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Additionally, we had planned to issue $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges of an anticipated transaction. Due to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound. A pretax cash gain of approximately $28 million was recorded in March 2011.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2011.

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, investing and financing activities for the nine months ended June 30, 2011 and 2010 are presented below.

	Nine Months Ended June 30		
	2011	2010	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 519,562	$ 594,564	$(75,002)
Investing activities	(393,656)	(362,787)	(30,869)
Financing activities	(140,429)	(162,597)	22,168
Change in cash and cash equivalents	(14,523)	69,180	(83,703)
Cash and cash equivalents at beginning of period	131,952	111,203	20,749
Cash and cash equivalents at end of period	$ 117,429	$ 180,383	$(62,954)

Cash flows from operating activities

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

For the nine months ended June 30, 2011, we generated operating cash flow of $519.6 million from operating activities compared with $594.6 million for the nine months ended June 30, 2010. The $75.0 million decrease in operating cash flows primarily reflects the timing of gas cost recoveries under our purchased gas cost mechanisms and other net working capital changes.

Cash flows from investing activities

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

Capital expenditures for fiscal 2011 are expected to range from $610 million to $625 million. For the nine months ended June 30, 2011, capital expenditures were $390.3 million compared with $362.3 million for the nine months ended June 30, 2010. The $28.0 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and the development of a new customer service system in the current year, partially offset by the costs incurred in the prior fiscal year to relocate the company's information technology data center.

Cash flows from financing activities

For the nine months ended June 30, 2011, our financing activities used $140.4 million of cash compared with $162.6 million of cash used in the prior-year period, primarily due to higher proceeds from debt issuances in the current year, including the following:

- $394.6 million net cash proceeds received in June 2011 related to the issuance of $400 million 5.50% senior notes due 2041.
- $20.1 million cash received in June 2011 related to the settlement of three Treasury locks associated with the $400 million 5.50% senior notes offering.
- $27.8 million cash received in March 2011 related to the unwinding of two Treasury locks.

These higher proceeds were partially offset by higher repayment activity, including the following:

- $360.1 million for scheduled long-term debt repayments. In the current-year period, $360.1 million of long-term debt was repaid, including our $350 million 7.375% senior notes that were paid on their maturity date on May 15, 2011. In the prior-year period, $0.1 million of long-term debt was repaid.
- $56.1 million for short-term debt repayments. In the current-year period, $132.1 million of short-term debt was repaid, compared with $76.0 million in the prior-year period.
- $4.1 million for the repurchase of equity awards. In the current-year period, we repurchased $5.3 million equity awards, compared with $1.2 million in the prior-year period.

The following table summarizes our share issuances for the nine months ended June 30, 2011 and 2010.

	Nine Months Ended June 30	
	2011	2010
Shares issued:		
Direct Stock Purchase Plan	—	103,529
Retirement Savings Plan and Trust	—	79,722
1998 Long-Term Incentive Plan	663,555	375,039
Outside Directors Stock-for-Fee Plan	1,801	2,689
Total shares issued	665,356	560,979

The year-over-year change in the number of shares issued primarily reflects an increased number of shares issued under our 1998 Long-Term Incentive Plan due to the exercise of stock options during the current year. This increase was partially offset by the fact that we are purchasing shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During the nine months ended June 30, 2011, we cancelled and retired 169,269 shares attributable to federal withholdings on equity awards and repurchased and retired 375,468 shares attributable to our accelerated share repurchase agreement, which are not included in the table above.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares, which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the daily volume-weighted average share price of our common stock over the duration of the agreement. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and three committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. As of June 30, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was $900.2 million. These facilities are described in further detail in Note 6 to the unaudited condensed consolidated financial statements.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we

were able to issue a total of $950 million in debt securities and $350 million in equity securities. At June 30, 2011, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

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 regulated and nonregulated 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). On May 11, 2011, Moody's upgraded our senior unsecured debt rating to Baa1 from Baa2, with a ratings outlook of stable, citing steady rate increases, improving credit metrics and a strategic focus on lower risk regulated activities as reasons for the upgrade. On June 2, 2011, Fitch upgraded our senior unsecured debt rating to A- from BBB+, with a ratings outlook of stable, citing a constructive regulatory environment, strategic focus on lower risk regulated activities and the geographic diversity of our regulated operations as key rating factors. As of June 30, 2011, S&P maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa1	A-
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently 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, 2011. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2011, September 30, 2010 and June 30, 2010:

	June 30, 2011		September 30, 2010		June 30, 2010	
	(In thousands, except percentages)					
Short-term debt	$ —	—	$ 126,100	2.8%	$ —	—
Long-term debt	2,208,540	48.6%	2,169,682	48.5%	2,169,677	48.4%
Shareholders' equity	2,335,824	51.4%	2,178,348	48.7%	2,313,730	51.6%
Total	$4,544,364	100.0%	$4,474,130	100.0%	$4,483,407	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 48.6 percent at June 30, 2011, 51.3 percent at September 30, 2010 and 48.4 percent at June 30, 2010. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2011.

Risk Management Activities

We conduct risk management activities through our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases.

In our nonregulated 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three and nine months ended June 30, 2011 and 2010:

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands)			
Fair value of contracts at beginning of period	$ 30,533	$(21,735)	$(49,600)	$(14,166)
Contracts realized/settled	(13)	(20)	(51,058)	(34,438)
Fair value of new contracts	1,801	182	2,872	(2,054)
Other changes in value	(34,845)	1,183	95,262	30,268
Fair value of contracts at end of period	$ (2,524)	$(20,390)	$ (2,524)	$(20,390)

The fair value of our natural gas distribution segment's financial instruments at June 30, 2011 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2011				
	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	$(3,235)	$711	$—	$—	$(2,524)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(3,235)	$711	$—	$—	$(2,524)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and nine months ended June 30, 2011 and 2010:

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
	(In thousands)			
Fair value of contracts at beginning of period	$(12,942)	$14,227	$(12,374)	$ 26,698
Contracts realized/settled	3,357	(8,100)	3,282	(32,342)
Fair value of new contracts	—	—	—	—
Other changes in value	(1,824)	(8,337)	(2,317)	3,434
Fair value of contracts at end of period	(11,409)	(2,210)	(11,409)	(2,210)
Netting of cash collateral	15,382	18,017	15,382	18,017
Cash collateral and fair value of contracts at period end	$ 3,973	$15,807	$ 3,973	$ 15,807

The fair value of our nonregulated segment's financial instruments at June 30, 2011 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2011				
	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	$(5,336)	$(6,097)	$24	$—	$(11,409)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(5,336)	$(6,097)	$24	$—	$(11,409)

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2011 and 2010, our total net periodic pension and other benefits costs were $42.7 million and $38.1 million. Those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2011 costs were determined using a September 30, 2010 measurement date. As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates, were significantly higher than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. We maintained the expected return on our pension plan assets

at 8.25 percent, despite the recent decline in the financial markets as we believe this rate reflects the average rate of expected earnings on plan assets that will fund our projected benefit obligation. Accordingly, our fiscal 2011 pension and postretirement medical costs for the nine months ended June 30, 2011 were significantly higher than the prior-year period.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits. During the election period, a limited number of participants chose to join the new plan, which resulted in an immaterial curtailment gain and a revaluation of the net periodic pension cost for the remainder of fiscal 2011. An immaterial curtailment gain was recorded in our second fiscal quarter. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective January 1, 2011 to 5.68 percent, which will reduce our net periodic pension cost by approximately $1.8 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based upon this valuation, we expect we will be required to contribute less than $2 million to our pension plans by September 15, 2011. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing a total of approximately $12 million to these plans during fiscal 2011.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three and nine month periods ended June 30, 2011 and 2010.

Natural Gas Distribution Sales and Statistical Data — Continuing Operations

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
METERS IN SERVICE, end of period				
Residential	2,845,554	2,841,716	2,845,554	2,841,716
Commercial	258,448	262,349	258,448	262,349
Industrial	2,319	2,359	2,319	2,359
Public authority and other	10,206	10,117	10,206	10,117
Total meters	3,116,527	3,116,541	3,116,527	3,116,541
INVENTORY STORAGE BALANCE — Bcf	36.3	32.8	36.3	32.8
SALES VOLUMES — MMcf[(1)]				
Gas sales volumes				
Residential	17,077	17,060	150,154	173,787
Commercial	14,149	13,690	79,632	88,260
Industrial	3,922	3,490	15,115	15,236
Public authority and other	1,863	1,373	8,764	8,713
Total gas sales volumes	37,011	35,613	253,665	285,996
Transportation volumes	31,036	28,678	102,824	101,449
Total throughput	68,047	64,291	356,489	387,445
OPERATING REVENUES (000's)[(1)]				
Gas sales revenues				
Residential	$ 232,725	$ 230,333	$1,379,223	$1,602,510
Commercial	118,916	116,933	593,860	685,996
Industrial	22,525	19,108	85,641	90,468
Public authority and other	12,013	9,125	58,096	61,595
Total gas sales revenues	386,179	375,499	2,116,820	2,440,569
Transportation revenues	13,946	13,303	47,364	46,276
Other gas revenues	6,906	7,517	23,723	25,187
Total operating revenues	$ 407,031	$ 396,319	$2,187,907	$2,512,032
Average transportation revenue per Mcf	$ 0.45	$ 0.46	$ 0.46	$ 0.46
Average cost of gas per Mcf sold	$ 5.59	$ 5.76	$ 5.19	$ 5.80

See footnote following these tables.

Natural Gas Distribution Sales and Statistical Data — Discontinued Operations

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
Meters in service, end of period	83,109	83,094	83,109	83,094
Inventory storage balance — Bcf	2.0	1.9	2.0	1.9
Sales volumes — MMcf				
Total gas sales volumes	936	726	7,910	8,187
Transportation volumes	1,192	1,633	4,813	5,648
Total throughput	2,128	2,359	12,723	13,835
Operating revenues (000's)	$11,524	$ 8,952	$71,047	$62,121

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2011	2010	2011	2010
CUSTOMERS, end of period				
Industrial	764	732	764	732
Municipal	61	61	61	61
Other	511	507	511	507
Total	1,336	1,300	1,336	1,300
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	21.4	21.9	21.4	21.9
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(1)]	141,294	127,861	468,943	478,075
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(1)	104,658	91,854	339,747	317,992
OPERATING REVENUES (000's)[(1)]				
Regulated transmission and storage	$ 53,570	$ 44,957	$ 157,553	$ 146,998
Nonregulated	491,285	427,405	1,550,456	1,652,453
Total operating revenues	$544,855	$472,362	$1,708,009	$1,799,451

Note to preceding tables:

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. During the nine months ended June 30, 2011, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter of the fiscal year ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the nine months ended June 30, 2011, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 12 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2010. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. ***Exhibits***

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

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: August 4, 2011

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
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*	
101.INS	XBRL Instance Document**	
101.SCH	XBRL Taxonomy Extension Schema**	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase**	
101.DEF	XBRL Taxonomy Extension Definition Linkbase**	
101.LAB	XBRL Taxonomy Extension Labels Linkbase**	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase**	

* 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.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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

Form 10-Q

(Mark One)

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

For the quarterly period ended December 31, 2011

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	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas	**75240**
(Address of principal executive offices)	*(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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐
(Do not check if a smaller reporting company)

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 February 3, 2012.

Class	Shares Outstanding
No Par Value	90,016,074

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
APS	Atmos Pipeline and Storage, LLC
Bcf	Billion cubic feet
CFTC	Commodity Futures Trading Commission
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MPSC	Mississippi Public Service Commission
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2011	September 30, 2011
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,896,521	$6,816,794
Less accumulated depreciation and amortization	1,650,308	1,668,876
Net property, plant and equipment	5,246,213	5,147,918
Current assets		
Cash and cash equivalents	85,160	131,419
Accounts receivable, net	489,797	273,303
Gas stored underground	325,669	289,760
Other current assets	360,615	316,471
Total current assets	1,261,241	1,010,953
Goodwill and intangible assets	740,196	740,207
Deferred charges and other assets	387,982	383,793
	$7,635,632	$7,282,871
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2011 — 90,007,057 shares September 30, 2011 — 90,296,482 shares	$ 448	$ 451
Additional paid-in capital	1,725,050	1,732,935
Retained earnings	607,485	570,495
Accumulated other comprehensive loss	(65,221)	(48,460)
Shareholders' equity	2,267,762	2,255,421
Long-term debt	2,206,193	2,206,117
Total capitalization	4,473,955	4,461,538
Current liabilities		
Accounts payable and accrued liabilities	432,332	291,205
Other current liabilities	357,353	367,563
Short-term debt	389,985	206,396
Current maturities of long-term debt	131	2,434
Total current liabilities	1,179,801	867,598
Deferred income taxes	981,559	960,093
Regulatory cost of removal obligation	437,660	428,947
Deferred credits and other liabilities	562,657	564,695
	$7,635,632	$7,282,871

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2011	2010
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 693,292	$ 703,462
Regulated transmission and storage segment	56,759	49,007
Nonregulated segment	444,176	475,640
Intersegment eliminations	(93,054)	(94,847)
	1,101,173	1,133,262
Purchased gas cost		
Natural gas distribution segment	402,207	412,526
Regulated transmission and storage segment	—	—
Nonregulated segment	428,771	450,462
Intersegment eliminations	(92,687)	(94,450)
	738,291	768,538
Gross profit	362,882	364,724
Operating expenses		
Operation and maintenance	116,062	114,490
Depreciation and amortization	59,215	54,777
Taxes, other than income	43,198	40,168
Total operating expenses	218,475	209,435
Operating income	144,407	155,289
Miscellaneous expense	(1,875)	(726)
Interest charges	35,442	38,895
Income from continuing operations before income taxes	107,090	115,668
Income tax expense	41,302	44,568
Income from continuing operations	65,788	71,100
Income from discontinued operations, net of tax ($1,559 and $1,890)	2,719	2,897
Net income	$ 68,507	$ 73,997
Basic earnings per share		
Income per share from continuing operations	$ 0.72	$ 0.78
Income per share from discontinued operations	0.03	0.03
Net income per share — basic	$ 0.75	$ 0.81
Diluted earnings per share		
Income per share from continuing operations	$ 0.72	$ 0.78
Income per share from discontinued operations	0.03	0.03
Net income per share — diluted	$ 0.75	$ 0.81
Cash dividends per share	$ 0.345	$ 0.340
Weighted average shares outstanding:		
Basic	90,254	90,082
Diluted	90,546	90,408

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2011	2010
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 68,507	$ 73,997
Adjustments to reconcile net income to net cash provided (used) by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	60,733	56,161
Charged to other accounts	78	46
Deferred income taxes	40,042	43,423
Other	4,692	4,712
Net assets / liabilities from risk management activities	(8,426)	5,304
Net change in operating assets and liabilities	(180,917)	(137,819)
Net cash provided (used) by operating activities	(15,291)	45,824
Cash Flows From Investing Activities		
Capital expenditures	(154,394)	(123,162)
Other, net	(1,080)	(370)
Net cash used in investing activities	(155,474)	(123,532)
Cash Flows From Financing Activities		
Net increase in short-term debt	173,905	112,628
Repayment of long-term debt	(2,303)	(10,000)
Cash dividends paid	(31,517)	(31,002)
Repurchase of common stock	(12,535)	—
Repurchase of equity awards	(3,120)	(3,231)
Issuance of common stock	76	7,253
Net cash provided by financing activities	124,506	75,648
Net decrease in cash and cash equivalents	(46,259)	(2,060)
Cash and cash equivalents at beginning of period	131,419	131,952
Cash and cash equivalents at end of period	$ 85,160	$ 129,892

See accompanying notes to condensed consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)
December 31, 2011

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other non-regulated businesses. Our corporate headquarters and shared-services function are located in Dallas, Texas and our customer support centers are located in Amarillo and Waco, Texas.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states. Our regulated activities also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc. (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

We operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

2. Unaudited Interim Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2011 are not indicative of our results of operations for the full 2012 fiscal year, which ends September 30, 2012.

We have evaluated subsequent events from the December 31, 2011 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). No events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three months ended December 31, 2011, two new accounting standards were announced that will become applicable to the Company in future periods. The first standard requires enhanced disclosure of offsetting arrangements for financial instruments and will become effective for annual periods beginning after January 1, 2013 and for interim periods within those annual periods. The second standard defers the effective date for amendments to the presentation of reclassifications of items out of accumulated other comprehensive income as prescribed by a previously issued standard, which were initially to be effective for interim and annual periods beginning after December 15, 2011. The adoption of these standards should not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the quarter ended December 31, 2011.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities, and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of December 31, 2011 and September 30, 2011 included the following:

	December 31, 2011	September 30, 2011
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$249,882	$254,666
Merger and integration costs, net	6,120	6,242
Deferred gas costs	88,799	33,976
Regulatory cost of removal asset	9,875	8,852
Environmental costs	288	385
Rate case costs	4,493	4,862
Deferred franchise fees	365	379
Other	3,345	3,534
	$363,167	$312,896
Regulatory liabilities:		
Deferred gas costs	$ 1,871	$ 8,130
Regulatory cost of removal obligation	469,685	464,025
Other	14,558	14,025
	$486,114	$486,180

The amounts above do not include regulatory assets and liabilities related to our Missouri, Illinois and Iowa service areas, which are classified as assets held for sale as discussed in Note 5.

During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of December 31, 2011, we had deferred $0.1 million associated with the requirements of this rule which are recorded as other costs in the regulatory assets table above.

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 applicable state regulatory commissions.

Comprehensive income

The following table presents the components of comprehensive income, net of related tax, for the three-month periods ended December 31, 2011 and 2010:

	Three Months Ended December 31	
	2011	2010
	(In thousands)	
Net income	$ 68,507	$ 73,997
Unrealized holding gains on investments, net of tax expense of $514 and $455 for the three months ended December 31, 2011 and 2010	901	776
Amortization and unrealized gain (loss) on treasury lock agreements, net of tax expense (benefit) of $(638) and $18,704 for the three months ended December 31, 2011 and 2010	(1,087)	31,847
Net unrealized gains (losses) on cash flow hedging transactions, net of tax expense (benefit) of $(10,597) and $6,617 for the three months ended December 31, 2011 and 2010	(16,575)	10,350
Comprehensive income	$ 51,746	$116,970

Accumulated other comprehensive loss, net of tax, as of December 31, 2011 and September 30, 2011 consisted of the following unrealized gains (losses):

	December 31, 2011	September 30, 2011
	(In thousands)	
Accumulated other comprehensive loss:		
Unrealized holding gains on investments	$ 3,459	$ 2,558
Treasury lock agreements	(35,244)	(34,157)
Cash flow hedges	(33,436)	(16,861)
	$(65,221)	$(48,460)

3. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the first quarter there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit risk-related or other contingent features that could cause payments to be accelerated when our financial instruments are in net liability positions.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We

manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2011-2012 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas costs adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas costs when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

The primary business in our nonregulated operations is to aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. We utilize proprietary and customer-owned transportation and storage assets to serve these customers, and will seek to maximize the value of this storage capacity through the arbitrage of pricing differences that occur over time by selling financial instruments at advantageous prices to lock in a gross profit margin to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control.

As a result of these activities, our nonregulated segment is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange traded options and swap contracts with counterparties. Future contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 59 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

As of December 31, 2011, we had three Treasury lock agreements outstanding to fix the Treasury yield component of $350 million 30-year unsecured notes, which we plan to issue to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extend through fiscal 2041.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of December 31, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(26,690)
	Cash Flow	—	44,428
	Not designated	13,964	46,944
		13,964	64,682

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of December 31, 2011 and September 30, 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $22.1 million and $28.8 million of cash held on deposit as of December 31, 2011 and September 30, 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 4.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
December 31, 2011:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 60,222	$ 60,222
Noncurrent commodity contracts	Deferred charges and other assets	—	58	58
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(57,988)	(57,988)
Noncurrent commodity contracts	Deferred credits and other liabilities	(69,755)	(12,012)	(81,767)
Total		(69,755)	(9,720)	(79,475)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	292	148,669	148,961
Noncurrent commodity contracts	Deferred charges and other assets	180	80,916	81,096
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[1]	(16,196)	(166,878)	(183,074)
Noncurrent commodity contracts	Deferred credits and other liabilities	(350)	(68,250)	(68,600)
Total		(16,074)	(5,543)	(21,617)
Total Financial Instruments		$(85,829)	$ (15,263)	$(101,092)

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.7 million related to risk management liabilities that were classified as assets held for sale at December 31, 2011.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2011:				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	—	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(31,064)	(31,064)
Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[(1)]	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$(79,277)	$(25,050)	$(104,327)

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended December 31, 2011 and 2010 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $8.4 million and $13.5 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three months ended December 31, 2011 and 2010 is presented below.

	Three Months Ended December 31	
	2011	2010
	(In thousands)	
Commodity contracts	$ 24,064	$ (1,723)
Fair value adjustment for natural gas inventory designated as the hedged item	(15,249)	15,625
Total impact on revenue	$ 8,815	$13,902
The impact on revenue is comprised of the following:		
Basis ineffectiveness	$ 841	$ 921
Timing ineffectiveness	7,974	12,981
	$ 8,815	$13,902

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. During the three months ended December 31, 2011, we recorded a $1.7 million charge to write down non-qualifying natural gas inventory to market. We did not record a writedown for nonqualifying natural gas inventory for the three months ended December 31, 2010.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 2011 and 2010 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended December 31, 2011		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(11,642)	$(11,642)
Loss arising from ineffective portion of commodity contracts	—	(430)	(430)
Total impact on revenue	—	(12,072)	(12,072)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(502)	—	(502)
Total Impact from Cash Flow Hedges	$(502)	$(12,072)	$(12,574)

	Three Months Ended December 31, 2010		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$(14,253)	$(14,253)
Loss arising from ineffective portion of commodity contracts	—	(444)	(444)
Total impact on revenue	—	(14,697)	(14,697)
Loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(670)	—	(670)
Total Impact from Cash Flow Hedges	$(670)	$(14,697)	$(15,367)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 2011 and 2010. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended December 31	
	2011	2010
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$ (1,403)	$31,425
Forward commodity contracts	(23,678)	1,657
Recognition of losses in earnings due to settlements:		
Treasury lock agreements	316	422
Forward commodity contracts	7,103	8,693
Total other comprehensive income (loss) from hedging, net of tax[1]	$(17,662)	$42,197

(1) Utilizing an income tax rate ranging from 37 percent to 39 percent comprised of the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our Treasury lock agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 2011. However, the table below does not include the expected recognition in earnings of our outstanding Treasury lock agreements as those instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
Next twelve months	$(1,266)	$(25,900)	$(27,166)
Thereafter	9,967	(7,536)	2,431
Total[1]	$ 8,701	$(33,436)	$(24,735)

(1) Utilizing an income tax rate ranging from 37 percent to 39 percent comprised of the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statement for the three months ended December 31, 2011 and 2010 was an increase (decrease) in revenue of ($2.2) million and $4.2 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of

these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

4. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the first quarter of fiscal 2012, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 9 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2011.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following table summarizes, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and September 30, 2011. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	December 31, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 472	$ —	$ —	$ 472
Nonregulated segment	33,768	256,098	—	(272,938)	16,928
Total financial instruments	33,768	256,570	—	(272,938)	17,400
Hedged portion of gas stored underground	77,551	—	—	—	77,551
Available-for-sale securities					
Money market funds	—	1,151	—	—	1,151
Registered investment companies	38,008	—	—	—	38,008
Bonds	—	18,346	—	—	18,346
Total available-for-sale securities	38,008	19,497	—	—	57,505
Total assets	$149,327	$276,067	$ —	$(272,938)	$152,456
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 86,301	$ —	$ —	$ 86,301
Nonregulated segment	51,117	254,012	—	(295,022)	10,107
Total liabilities	$ 51,117	$340,313	$ —	$(295,022)	$ 96,408

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,841	$ —	$ —	$ 1,841
Nonregulated segment	15,262	97,396	—	(95,156)	17,502
Total financial instruments	15,262	99,237	—	(95,156)	19,343
Hedged portion of gas stored underground	47,940	—	—	—	47,940
Available-for-sale securities					
Money market funds	—	1,823	—	—	1,823
Registered investment companies	36,444	—	—	—	36,444
Bonds	—	14,366	—	—	14,366
Total available-for-sale securities	36,444	16,189	—	—	52,633
Total assets	$ 99,646	$115,426	$ —	$ (95,156)	$119,916
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 81,118	$ —	$ —	$ 81,118
Nonregulated segment	22,091	115,617	—	(123,943)	13,765
Total liabilities	$ 22,091	$196,735	$ —	$(123,943)	$ 94,883

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences. This level also includes municipal and corporate bonds where market data for pricing is observable.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of December 31, 2011, we had $22.1 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $11.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $10.7 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of December 31, 2011				
Domestic equity mutual funds	$27,881	$5,447	$ —	$33,328
Foreign equity mutual funds	4,659	305	(284)	4,680
Bonds	18,323	45	(22)	18,346
Money market funds	1,151	—	—	1,151
	$52,014	$5,797	$(306)	$57,505
As of September 30, 2011				
Domestic equity mutual funds	$27,748	$4,074	$ —	$31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	—	—	1,823
	$48,558	$4,351	$(276)	$52,633

At December 31, 2011 and September 30, 2011, our available-for-sale securities included $39.2 million and $38.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At December 31, 2011 we maintained investments in bonds that have contractual maturity dates ranging from January 2012 through July 2016.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

We maintained an investment in one foreign equity mutual fund with a fair value of $2.2 million in an unrealized loss position of $0.3 million as of December 31, 2011. This fund has been in an unrealized loss position for less than twelve months. Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other than temporary as of December 31, 2011. We also maintained several bonds with a cumulative fair value of $6.5 million in an unrealized loss position of less than $0.1 million as of December 31, 2011. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment grade, we do not consider this impairment to be other than temporary as of December 31, 2011.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of December 31, 2011:

	December 31, 2011
	(In thousands)
Carrying Amount	$2,210,262
Fair Value	$2,572,094

5. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals, which we currently anticipate will occur during fiscal 2012.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as “held for sale” in other current assets and liabilities in our consolidated balance sheets at December 31, 2011 and September 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

	Three Months Ended December 31	
	2011	2010
	(In thousands)	
Operating revenues	$23,451	$23,733
Purchased gas cost	14,951	14,897
Gross profit	8,500	8,836
Operating expenses	4,174	4,016
Operating income	4,326	4,820
Other nonoperating expense	(48)	(33)
Income from discontinued operations before income taxes	4,278	4,787
Income tax expense	1,559	1,890
Net income	$ 2,719	$ 2,897

The following table presents balance sheet data related to assets held for sale.

	December 31, 2011	September 30, 2011
	(In thousands)	
Net plant, property & equipment	$127,227	$127,577
Gas stored underground	14,257	11,931
Other current assets	3,773	786
Deferred charges and other assets	62	277
Assets held for sale	$145,319	$140,571
Accounts payable and accrued liabilities	$ 9,945	$ 1,917
Other current liabilities	5,459	4,877
Regulatory cost of removal obligation	10,367	10,498
Deferred credits and other liabilities	1,175	1,153
Liabilities held for sale	$ 26,946	$ 18,445

6. Debt

The nature and terms of our debt instruments are described in detail in Note 7 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes in the terms of our debt instruments during the three months ended December 31, 2011.

Long-term debt

Long-term debt at December 31, 2011 and September 30, 2011 consisted of the following:

	December 31, 2011	September 30, 2011
	(In thousands)	
Unsecured 10% Notes, redeemed December 2011	$ —	$ 2,303
Unsecured 5.125% Senior Notes, due January 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Medium term notes		
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term note due in installments through 2013	262	262
Total long-term debt	2,210,262	2,212,565
Less:		
Original issue discount on unsecured senior notes and debentures	(3,938)	(4,014)
Current maturities	(131)	(2,434)
	$2,206,193	$2,206,117

Our unsecured 10% notes were paid on their maturity date on December 31, 2011, and were not replaced.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $750 million commercial paper program and four committed revolving credit facilities with third-party lenders. As a result, we have approximately $985 million of working capital funding. Additionally, our $750 million unsecured credit facility has an accordion feature which, if utilized, would increase borrowing capacity to $1.0 billion. At December 31, 2011 and September 30, 2011, there was $390.0 million and $206.4 million outstanding under our commercial paper program. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding, including a five-year $750 million unsecured facility, a $25 million unsecured facility and a $10 million revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.2 million at December 31, 2011.

In addition to these third-party facilities, our regulated operations had a $350 million intercompany revolving credit facility with AEH. This facility was replaced on January 1, 2012 with a $500 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility, expiring in December 2013, with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH. Due to outstanding letters of credit and various covenants, including covenants based on working capital, the amount available to AEM under this credit facility was $110.0 million at December 31, 2011.

To supplement borrowings under this facility, AEH had a $350 million intercompany demand credit facility with AEC. This facility was replaced on January 1, 2012 with a $500 million intercompany facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement

has been approved by all requisite state regulatory commissions. At December 31, 2011, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Debt Covenants

The availability of funds under our regulated 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 each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2011, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 56 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

AEM is required by the financial covenants in its facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At December 31, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.39 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at December 31, 2011, AEM's net working capital was $118.2 million and its tangible net worth was $147.8 million.

In addition to these financial covenants, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, 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.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other 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.

We were in compliance with all of our debt covenants as of December 31, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

7. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, for which vesting is predicated solely on the passage of time granted under the 1998 Long-Term Incentive Plan, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three months ended December 31, 2011 and 2010 are calculated as follows:

	Three Months Ended December 31	
	2011	2010
	(In thousands, except per share amounts)	
Basic Earnings Per Share from continuing operations		
Income from continuing operations	$65,788	$71,100
Less: Income from continuing operations allocated to participating securities	685	748
Income from continuing operations available to common shareholders	$65,103	$70,352
Basic weighted average shares outstanding	90,254	90,082
Income from continuing operations per share — Basic	$ 0.72	$ 0.78
Basic Earnings Per Share from discontinued operations		
Income from discontinued operations	$ 2,719	$ 2,897
Less: Income from discontinued operations allocated to participating securities	28	31
Income from discontinued operations available to common shareholders	$ 2,691	$ 2,866
Basic weighted average shares outstanding	90,254	90,082
Income from discontinued operations per share — Basic	$ 0.03	$ 0.03
Net income per share — Basic	$ 0.75	$ 0.81
Diluted Earnings Per Share from continuing operations		
Income from continuing operations available to common shareholders	$65,103	$70,352
Effect of dilutive stock options and other shares	1	2
Income from continuing operations available to common shareholders	$65,104	$70,354
Basic weighted average shares outstanding	90,254	90,082
Additional dilutive stock options and other shares	292	326
Diluted weighted average shares outstanding	90,546	90,408
Income from continuing operations per share — Diluted	$ 0.72	$ 0.78

	Three Months Ended December 31	
	2011	2010
	(In thousands, except per share amounts)	
Diluted Earnings Per Share from discontinued operations		
Income from discontinued operations available to common shareholders	$ 2,691	$ 2,866
Effect of dilutive stock options and other shares	—	—
Income from discontinued operations available to common shareholders	$ 2,691	$ 2,866
Basic weighted average shares outstanding	90,254	90,082
Additional dilutive stock options and other shares	292	326
Diluted weighted average shares outstanding	90,546	90,408
Income from discontinued operations per share — Diluted	$ 0.03	$ 0.03
Net income per share — Diluted	$ 0.75	$ 0.81

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three months ended December 31, 2011 and 2010 as their exercise price was less than the average market price of the common stock during that period.

Share Repurchase Program

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. As of December 31, 2011, 387,991 shares had been repurchased for an aggregate value of $12.5 million.

8. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2011 and 2010 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,298	$ 4,380	$4,088	$3,601
Interest cost	6,677	6,924	3,465	3,203
Expected return on assets	(5,368)	(5,963)	(652)	(682)
Amortization of transition asset	—	—	378	378
Amortization of prior service cost	(35)	(112)	(362)	(362)
Amortization of actuarial loss	4,142	3,494	662	87
Net periodic pension cost	$ 9,714	$ 8,723	$7,579	$6,225

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2011 and 2010 are as follows:

	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
Discount rate	5.05%	5.39%	5.05%	5.39%
Rate of compensation increase	3.50%	4.00%	N/A	N/A
Expected return on plan assets	7.75%	8.25%	4.70%	5.00%

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2012. Based upon this valuation, we expect we will be required to contribute between $25 million and $30 million to our pension plans by September 15, 2012.

We contributed $4.8 million to our other post-retirement benefit plans during the three months ended December 31, 2011. We expect to contribute between $20 million and $25 million to these plans during fiscal 2012.

9. 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 the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2011.

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky, *Billy Joe Honeycutt et al. vs. Atmos Energy Corporation, et al.*, which is related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied.

However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On October 17, 2011, we filed our brief of appellants with the Kentucky Court of Appeals, appealing the verdict of the trial court. The appellees in this case subsequently filed their reply brief with the Court of Appeals on January 16, 2012, with our reply brief due to be filed with the Court by March 16, 2012.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, *Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles*, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. As of this date, the Court has not yet ruled on the motion.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter. However, we continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2011, AEH was committed to purchase 103.1 Bcf within one year, 35.3 Bcf within one to three years and 0.3 Bcf after three years under indexed contracts. AEH is committed to purchase 3.4 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $2.82 to $6.36 per Mcf. Purchases under these contracts totaled $312.1 million and $334.2 million for the three months ended December 31, 2011 and 2010.

Our natural gas distribution divisions, except for our 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 and fixed prices. The estimated commitments under these contracts as of December 31, 2011 are as follows (in thousands):

2012	$149,788
2013	82,778
2014	68,124
Thereafter	—
	$300,690

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. There were no material changes to the estimated storage and transportation fees for the quarter ended December 31, 2011.

Regulatory Matters

As previously described in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. Since that time, we have fully cooperated with the Commission during this investigation.

The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company has paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.

As discussed in Note 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011, in 2010, our Mid-Tex Division agreed to install 100,000 steel service line replacements by September 30, 2012. As of December 31, 2011, we had replaced 60,184 lines and are on schedule for completion in September 2012. Under the terms of the agreement, special rate recovery of the associated return, depreciation and taxes is approved for lines replaced between October 1, 2010 and September 30, 2012. Since October 1, 2010, we have spent $64.0 million on steel service line replacements.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission (CFTC) to establish rules and regulations for implementation of many of the provisions of the Dodd-Frank Act. Although the CFTC and SEC have issued a number of rules and regulations, we expect additional rules and regulations to be issued, which should provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation and related rules and regulations. We also anticipate additional reporting and disclosure obligations will be imposed.

As of December 31, 2011, annual rate filing mechanisms were in progress in our Louisiana and Mississippi service areas and there was one other ratemaking activity in progress in our Kansas service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

10. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three months ended December 31, 2011, there were no material changes in our concentration of credit risk.

11. Segment Information

As discussed in Note 1 above, we operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- The *nonregulated segment*, which is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

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 natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution 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, 2011. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three month periods ended December 31, 2011 and 2010 by segment are presented in the following tables:

	Three Months Ended December 31, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$693,068	$19,440	$388,665	$ —	$1,101,173
Intersegment revenues	224	37,319	55,511	(93,054)	—
	693,292	56,759	444,176	(93,054)	1,101,173
Purchased gas cost	402,207	—	428,771	(92,687)	738,291
Gross profit	291,085	56,759	15,405	(367)	362,882
Operating expenses					
Operation and maintenance	93,414	16,965	6,051	(368)	116,062
Depreciation and amortization	50,831	7,651	733	—	59,215
Taxes, other than income	38,479	3,784	935	—	43,198
Total operating expenses	182,724	28,400	7,719	(368)	218,475
Operating income	108,361	28,359	7,686	1	144,407
Miscellaneous income (expense)	(1,756)	(280)	36	125	(1,875)
Interest charges	27,855	7,209	252	126	35,442
Income from continuing operations before income taxes	78,750	20,870	7,470	—	107,090
Income tax expense	30,845	7,456	3,001	—	41,302
Income from continuing operations	47,905	13,414	4,469	—	65,788
Income from discontinued operations, net of tax	2,719	—	—	—	2,719
Net income	$ 50,624	$13,414	$ 4,469	$ —	$ 68,507
Capital expenditures	$128,733	$24,120	$ 1,541	$ —	$ 154,394

	Three Months Ended December 31, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$703,261	$21,233	$408,768	$ —	$1,133,262
Intersegment revenues	201	27,774	66,872	(94,847)	—
	703,462	49,007	475,640	(94,847)	1,133,262
Purchased gas cost	412,526	—	450,462	(94,450)	768,538
Gross profit	290,936	49,007	25,178	(397)	364,724
Operating expenses					
Operation and maintenance	89,229	15,574	10,084	(397)	114,490
Depreciation and amortization	47,894	5,799	1,084	—	54,777
Taxes, other than income	34,448	3,553	2,167	—	40,168
Total operating expenses	171,571	24,926	13,335	(397)	209,435
Operating income	119,365	24,081	11,843	—	155,289
Miscellaneous income (expense)	(698)	(282)	290	(36)	(726)
Interest charges	29,697	8,064	1,170	(36)	38,895
Income from continuing operations before income taxes	88,970	15,735	10,963	—	115,668
Income tax expense	34,549	5,633	4,386	—	44,568
Income from continuing operations	54,421	10,102	6,577	—	71,100
Income from discontinued operations, net of tax	2,897	—	—	—	2,897
Net income	$ 57,318	$10,102	$ 6,577	$ —	$ 73,997
Capital expenditures	$109,499	$12,739	$ 924	$ —	$ 123,162

Balance sheet information at December 31, 2011 and September 30, 2011 by segment is presented in the following tables.

	December 31, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,328,612	$ 855,245	$ 62,356	$ —	$5,246,213
Investment in subsidiaries	672,300	—	(2,096)	(670,204)	—
Current assets					
Cash and cash equivalents	63,031	—	22,129	—	85,160
Assets from risk management activities	292	—	10,732	—	11,024
Other current assets	912,185	13,418	453,571	(214,117)	1,165,057
Intercompany receivables	567,587	—	—	(567,587)	—
Total current assets	1,543,095	13,418	486,432	(781,704)	1,261,241
Intangible assets	—	—	196	—	196
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	180	—	6,196	—	6,376
Deferred charges and other assets	359,860	11,297	10,449	—	381,606
	$7,476,955	$1,012,341	$598,244	$(1,451,908)	$7,635,632
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,267,762	$ 278,515	$393,785	$ (672,300)	$2,267,762
Long-term debt	2,206,062	—	131	—	2,206,193
Total capitalization	4,473,824	278,515	393,916	(672,300)	4,473,955
Current liabilities					
Current maturities of long-term debt	—	—	131	—	131
Short-term debt	583,980	—	—	(193,995)	389,985
Liabilities from risk management activities	14,521	—	4,623	—	19,144
Other current liabilities	606,357	11,929	170,281	(18,026)	770,541
Intercompany payables	—	531,126	36,461	(567,587)	—
Total current liabilities	1,204,858	543,055	211,496	(779,608)	1,179,801
Deferred income taxes	813,423	181,641	(13,505)	—	981,559
Noncurrent liabilities from risk management activities	70,105	—	5,484	—	75,589
Regulatory cost of removal obligation	437,660	—	—	—	437,660
Deferred credits and other liabilities	477,085	9,130	853	—	487,068
	$7,476,955	$1,012,341	$598,244	$(1,451,908)	$7,635,632

	September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,248,198	$ 838,302	$ 61,418	$ —	$5,147,918
Investment in subsidiaries	670,993	—	(2,096)	(668,897)	—
Current assets					
Cash and cash equivalents	24,646	—	106,773	—	131,419
Assets from risk management activities	843	—	17,501	—	18,344
Other current assets	655,716	15,413	386,215	(196,154)	861,190
Intercompany receivables	569,898	—	—	(569,898)	—
Total current assets	1,251,103	15,413	510,489	(766,052)	1,010,953
Intangible assets	—	—	207	—	207
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	998	—	—	—	998
Deferred charges and other assets	353,960	18,028	10,807	—	382,795
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,255,421	$ 265,102	$405,891	$ (670,993)	$2,255,421
Long-term debt	2,205,986	—	131	—	2,206,117
Total capitalization	4,461,407	265,102	406,022	(670,993)	4,461,538
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	387,691	—	—	(181,295)	206,396
Liabilities from risk management activities	11,916	—	3,537	—	15,453
Other current liabilities	474,783	10,369	170,926	(12,763)	643,315
Intercompany payables	—	543,084	26,814	(569,898)	—
Total current liabilities	876,693	553,453	201,408	(763,956)	867,598
Deferred income taxes	789,649	173,351	(2,907)	—	960,093
Noncurrent liabilities from risk management activities	67,862	—	10,227	—	78,089
Regulatory cost of removal obligation	428,947	—	—	—	428,947
Deferred credits and other liabilities	473,602	12,218	786	—	486,606
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of December 31, 2011, the related condensed consolidated statements of income for the three-month periods ended December 31, 2011 and 2010, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2011 and 2010. 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 and subsidiaries as of September 30, 2011, 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 22, 2011, 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, 2011, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 8, 2012

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, 2011.

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

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

OVERVIEW

Atmos Energy and its subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, which we currently anticipate will occur during fiscal 2012, we will operate in nine states.

Through our nonregulated businesses, we provide natural gas management and transportation services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and

Southeast and natural gas transportation and storage services to certain of our natural gas distribution divisions and to third parties. Through our asset optimization activities, we also seek to maximize the economic value associated with the storage and transportation capacity we own or control.

As discussed in Note 11, we operate the Company through the following three segments:

- the *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and
- the *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

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, the 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 fiscal year ended September 30, 2011 and include the following:

- Regulation
- Revenue Recognition
- Allowance for Doubtful Accounts
- Financial Instruments and Hedging Activities
- Impairment Assessments
- Pension and Other Postretirement Plans
- Fair Value Measurements

Our critical accounting policies are reviewed quarterly by the Audit Committee. There were no significant changes to these critical accounting policies during the three months ended December 31, 2011.

RESULTS OF OPERATIONS

We reported net income of $68.5 million, or $0.75 per diluted share for the three months ended December 31, 2011 compared with net income of $74.0 million, or $0.81 per diluted share in the prior-year quarter. Regulated operations contributed 93 percent of our net income during this period with our nonregulated operations contributing the remaining seven percent. Excluding the impact of unrealized margins, diluted earnings per share decreased $0.20 compared with the prior-year quarter. The $0.20 per diluted share decrease primarily reflects the adverse impact of unfavorable natural gas market conditions on our nonregulated segment and increased operating expenses in our natural gas distribution segment. These decreases were partially offset by a five percent increase in consolidated throughput in our regulated transmission and storage segment and the favorable impact of ratemaking efforts in our natural gas distribution segment.

Due to the pending sale of our Missouri, Illinois and Iowa service areas, the results of operations for these three service areas are shown in discontinued operations. During the current-year quarter, discontinued operations generated net income of $2.7 million, or $0.03 per diluted share, compared with net income of $2.9 million, or $0.03 per diluted share in the prior-year quarter. Continuing operations in the current quarter generated net income of $65.8 million, or $0.72 per diluted share, compared with net income of $71.1 million, or $0.78 per diluted share from continuing operations in the prior-year quarter.

The following table presents our consolidated financial highlights for the three months ended December 31, 2011 and 2010:

	Three Months Ended December 31	
	2011	2010
	(In thousands, except per share data)	
Operating revenues	$1,101,173	$1,133,262
Gross profit	362,882	364,724
Operating expenses	218,475	209,435
Operating income	144,407	155,289
Miscellaneous expense	(1,875)	(726)
Interest charges	35,442	38,895
Income from continuing operations before income taxes	107,090	115,668
Income tax expense	41,302	44,568
Income from continuing operations	65,788	71,100
Income from discontinued operations, net of tax	2,719	2,897
Net income	$ 68,507	$ 73,997
Diluted net income per share from continuing operations	$ 0.72	$ 0.78
Diluted net income per share from discontinued operations	0.03	0.03
Diluted net income per share	$ 0.75	$ 0.81

The following table reflects our consolidated net income and diluted earnings per share in our regulated and nonregulated operations:

	Three Months Ended December 31		
	2011	2010	Change
	(In thousands, except per share data)		
Regulated operations	$61,319	$64,523	$(3,204)
Nonregulated operations	4,469	6,577	(2,108)
Net income from continuing operations	65,788	71,100	(5,312)
Net income from discontinued operations	2,719	2,897	(178)
Net income	$68,507	$73,997	$(5,490)
Diluted EPS from continuing regulated operations	$ 0.67	$ 0.71	$ (0.04)
Diluted EPS from nonregulated operations	0.05	0.07	(0.02)
Diluted EPS from continuing operations	0.72	0.78	(0.06)
Diluted EPS from discontinued operations	0.03	0.03	—
Consolidated diluted EPS	$ 0.75	$ 0.81	$ (0.06)

Three Months Ended December 31, 2011 compared with Three Months Ended December 31, 2010

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for over 90 percent of our residential and commercial meters in the following states for the following time periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
Virginia	January — December

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Finally, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or use alternative energy sources.

In May 2011, we announced that we had entered into a definitive agreement to sell substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables as discontinued operations and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2011 and 2010 are presented below.

	Three Months Ended December 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Gross profit	$291,085	$290,936	$ 149
Operating expenses	182,724	171,571	11,153
Operating income	108,361	119,365	(11,004)
Miscellaneous expense	(1,756)	(698)	(1,058)
Interest charges	27,855	29,697	(1,842)
Income from continuing operations before income taxes	78,750	88,970	(10,220)
Income tax expense	30,845	34,549	(3,704)
Income from continuing operations	47,905	54,421	(6,516)
Income from discontinued operations, net of tax	2,719	2,897	(178)
Net income	$ 50,624	$ 57,318	$ (6,694)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	84,890	84,137	753
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	32,832	32,218	614
Consolidated natural gas distribution throughput from continuing operations — MMcf	117,722	116,355	1,367
Consolidated natural gas distribution throughput from discontinued operations — MMcf	4,026	4,189	(163)
Total consolidated natural gas distribution throughput — MMcf	121,748	120,544	1,204
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.45	$ 0.49	$ (0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.78	$ 4.92	$ (0.14)

The $0.1 million increase in natural gas distribution gross profit primarily reflects the following:

- $4.6 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana and Kentucky service areas.
- A two percent rise in transportation volumes resulting in a $0.5 million increase in transportation margins.

These increases were largely offset by the quarter-over-quarter negative effect of the weather normalization adjustment in the Mid-Tex Division, which required utilizing updated weather data in the calculation of the adjustment in the current quarter.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $11.2 million, primarily due to the following:

- $2.9 million increase in depreciation and amortization and a $2.6 million increase in ad valorem taxes associated with an increase in our net plant as a result of our capital investments in the prior year.
- $3.5 million net increase in legal and other administrative costs.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended December 31, 2011 and 2010. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31		
	2011	2010	Change
	(In thousands)		
Mid-Tex	$ 48,449	$ 57,439	$ (8,990)
Kentucky/Mid-States	16,318	16,853	(535)
Louisiana	15,201	14,961	240
West Texas	10,675	9,520	1,155
Mississippi	10,132	10,215	(83)
Colorado-Kansas	8,179	7,702	477
Other	(593)	2,675	(3,268)
Total	$108,361	$119,365	$(11,004)

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the three months ended December 31, 2011 are discussed below. The amounts described below represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a final order from a commission or other governmental authority.

Annual net operating income increases totaling $4.3 million resulting from ratemaking activity became effective in the quarter ended December 31, 2011 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Rate case filings	$ 545
Infrastructure programs	3,744
	$4,289

Additionally, the following ratemaking efforts were in progress during the first quarter of fiscal 2012 but had not been completed as of December 31, 2011.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Ad Valorem[1]	Kansas	$ 167
Louisiana	Rate Stabilization Clause	TransLa	—
Mississippi	Stable Rate Filing[2]	Mississippi	5,303
			$5,470

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates. The Kansas Commission approved the filing on January 14, 2012.

(2) The Mississippi Commission issued a final order on January 11, 2012 approving a $4.3 million increase to operating income.

Subsequent to December 31, 2011, we filed five rate actions requesting a total increase in annual operating income of $66.8 million in our Mid-Tex, West Texas, Kansas and Georgia service areas. In our Mid-Tex service area, we filed a rate case requesting a $46.0 million annual increase in operating income as well as our first City of Dallas Annual Rate Review filing in which we requested a $2.5 million increase to operating income. In our West Texas and Kansas service areas, we filed rate cases requesting an increase in annual operating income of $11.1 million and $6.1 million. In our Georgia service area, we requested an increase in annual operating income of $1.1 million under the annual pipeline replacement program.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return for our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate case that was completed during the three months ended December 31, 2011.

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2012 Rate Case Filings:			
West Texas — Environs	Texas	$545	11/08/2011
Total 2012 Rate Case Filings		$545	

Infrastructure Programs

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates during the three months ended December 31, 2011.

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2012 Infrastructure Programs:				
Kentucky/Mid-States — Georgia	09/2010	$ 7,160	$1,215	10/01/2011
Kentucky/Mid-States — Kentucky	09/2012	17,347	2,529	10/01/2011
Total 2012 Infrastructure Programs		$24,507	$3,744	

Annual Rate Filing Mechanism

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have annual rate filing mechanisms in our Louisiana, Georgia and Mississippi service areas and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division, Georgia rate adjustment mechanism in Kentucky/Mid-States and a rate stabilization clause in the Louisiana Division. There were no annual rate filing mechanisms completed during the three months ended December 31, 2011.

Other Ratemaking Activity

There was no other ratemaking activity completed during the three months ended December 31, 2011.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline–Texas Division. The Atmos Pipeline–Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Further, as the Atmos Pipeline–Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. Finally, as a regulated pipeline, the operations of the Atmos Pipeline–Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2011 and 2010 are presented below.

	Three Months Ended December 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 37,343	$ 27,535	$ 9,808
Third-party transportation	14,939	16,512	(1,573)
Storage and park and lend services	1,806	2,170	(364)
Other	2,671	2,790	(119)
Gross profit	56,759	49,007	7,752
Operating expenses	28,400	24,926	3,474
Operating income	28,359	24,081	4,278
Miscellaneous expense	(280)	(282)	2
Interest charges	7,209	8,064	(855)
Income before income taxes	20,870	15,735	5,135
Income tax expense	7,456	5,633	1,823
Net income	$ 13,414	$ 10,102	$ 3,312
Gross pipeline transportation volumes — MMcf	160,829	153,178	7,651
Consolidated pipeline transportation volumes — MMcf	105,037	99,841	5,196

The $7.8 million increase in regulated transmission and storage gross profit was primarily a result of rate design changes approved in the rate case in the prior year. The current rate design allows us to recover fixed costs associated with transportation and storage services through monthly customer charges rather than through a volumetric charge, which should allow us to earn margin more ratably during the fiscal year. Additionally, consolidated throughput increased about five percent due to increased through-system demand and the execution of new delivery contracts with local producers.

Operating expenses increased $3.5 million primarily due to the following:

- $1.3 million increase due to higher levels of pipeline maintenance activities.
- $1.9 million increase due to higher depreciation expense, resulting from the rate case and a higher investment in net plant.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. This business is significantly influenced by competitive factors in the industry, general economic conditions and other factors that could affect the demand for natural gas. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas used to serve those customers. Further, delivered gas margins can be affected by the price of natural gas in the different locations where we buy and sell gas.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. The majority of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions. These margins are influenced by natural gas market conditions including, but not limited to, the price of natural gas, demand for natural gas, the level of domestic natural gas inventory levels and the level of volatility between current (spot) and future natural gas prices. These margins are also impacted by our ability to minimize the demand fees paid to contract for storage capacity.

Higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices may also cause customers to conserve or use alternative energy sources. Lower natural gas prices generally reduce these risks.

The level of volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads and basis differentials from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Conversely, a lack of price volatility reduces opportunities to create value from arbitrage spreads and basis differentials.

Our nonregulated segment manages its exposure to natural gas commodity price risk through a combination of physical storage and financial instruments. Therefore, results for this segment will include unrealized gains or losses on its net physical gas position and the related financial instruments used to manage commodity price risk. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will generally record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the three months ended December 31, 2011 and 2010 are presented below.

	Three Months Ended December 31		
	2011	2010	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 11,113	$ 16,041	$ (4,928)
Storage and transportation services	3,189	3,349	(160)
Other	1,017	1,319	(302)
	15,319	20,709	(5,390)
Asset optimization[1]	(21,594)	3,965	(25,559)
Total realized margins	(6,275)	24,674	(30,949)
Unrealized margins	21,680	504	21,176
Gross profit	15,405	25,178	(9,773)
Operating expenses	7,719	13,335	(5,616)
Operating income	7,686	11,843	(4,157)
Miscellaneous income	36	290	(254)
Interest charges	252	1,170	(918)
Income before income taxes	7,470	10,963	(3,493)
Income tax expense	3,001	4,386	(1,385)
Net income	$ 4,469	$ 6,577	$ (2,108)
Gross nonregulated delivered gas sales volumes — MMcf	106,462	107,712	(1,250)
Consolidated nonregulated delivered gas sales volumes — MMcf	90,870	94,538	(3,668)
Net physical position (Bcf)	35.6	19.6	16.0

[1] Net of storage fees of $4.7 million and $3.3 million.

Results for our nonregulated operations during the first fiscal quarter were adversely influenced by continued unfavorable natural gas market conditions. Historically high natural gas storage levels caused by growing domestic natural gas production coupled with an unseasonably warm start to the 2011-2012 winter heating season caused natural gas prices to fall and for spot to forward spread values and basis differentials to remain compressed. Further, unseasonably warm weather reduced the demand for natural gas.

We anticipate natural gas storage levels will remain high for an extended period of time and for unseasonably warm weather to continue during the second quarter of fiscal 2012. Therefore, we expect gas prices to remain relatively low with little volatility and spot to forward spread values and basis differentials to remain compressed. Further, sales of natural gas could be adversely impacted. Accordingly, although we anticipate continuing to profit from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities will be more consistent with the reduced margins we realized in fiscal 2011 than in previous years.

Realized margins for gas delivery, storage and transportation services and other services were $15.3 million during the three months ended December 31, 2011 compared with $20.7 million for the prior-year quarter. The decrease reflects the following:

- A four percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather particularly in the latter half of the quarter, which reduced sales to our utility, municipal and other

weather-sensitive customers. These decreases were partially offset by a 6 percent period-over-period increase in sales to new and existing industrial and power generation customers.

- A decrease in gas delivery per-unit margins from $0.15/Mcf in the prior-year quarter to $0.10/Mcf in the current-year quarter primarily due to lower basis differentials resulting from increased natural gas supply coupled with increased transportation costs.

Asset optimization margins decreased $25.6 million from the prior-year quarter. In the prior year quarter, due to compressed spot to forward spread values, AEH traded more frequently in the daily cash market and earned intramonth trading gains that exceeded the demand fees paid for its contracted storage capacity.

In the current year quarter, AEH elected to take advantage of falling natural prices by purchasing and injecting a net 15.7 Bcf into storage and capturing incremental physical to forward spread values that should be realized in future periods. As a result of this decision, we realized no storage withdrawal gains to offset the realized losses on the settlement of financial instruments used to hedge our natural gas purchases.

We anticipate this trend will continue during the fiscal second quarter; however, a substantial portion of the incremental margins captured during the quarter are currently anticipated to be realized during the third and fourth quarter of fiscal 2012.

Realized asset optimization margins for the current-year quarter also included a $1.7 million charge to write-down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

The $21.2 million increase in unrealized margins primarily reflects unrealized gains on the financial instruments executed during the quarter to capture incremental physical to forward spreads as a result of falling natural gas prices.

Operating expenses decreased $5.6 million due to the following:

- $3.1 million decrease in insurance and legal costs as a result of the resolution of the FERC matter and the timing of activity pertaining to other litigation.
- $1.4 million decrease in employee related expenses.

Interest charges decreased $0.9 million primarily due to a decrease in commitment fees.

Liquidity and Capital Resources

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require.

We intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for the remainder of fiscal 2012.

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, investing and financing activities for the three months ended December 31, 2011 and 2010 are presented below.

	Three Months Ended December 31		
	2011	2010	2011 vs. 2010
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ (15,291)	$ 45,824	$(61,115)
Investing activities	(155,474)	(123,532)	(31,942)
Financing activities	124,506	75,648	48,858
Change in cash and cash equivalents	(46,259)	(2,060)	(44,199)
Cash and cash equivalents at beginning of period	131,419	131,952	(533)
Cash and cash equivalents at end of period	$ 85,160	$ 129,892	$(44,732)

Cash flows from operating activities

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

The $61.1 million decrease in operating cash flows primarily reflects the effect of purchasing natural gas and injecting it into storage in our nonregulated operations in order to capture incremental value anticipated to be realized in the third and fourth quarter of fiscal 2012, as well as the timing of customer collections and vendor payments.

Cash flows from investing activities

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

Capital expenditures for fiscal 2012 are expected to range from $680 million to $700 million. For the three months ended December 31, 2011, capital expenditures were $154.4 million compared with $123.2 million for the three months ended December 31, 2010. The $31.2 million increase in capital expenditures primarily reflects spending for the steel service line replacement program in the Mid-Tex Division and the development of new customer billing and information systems for our natural gas distribution segment.

Cash flows from financing activities

The $48.9 million increase in financing cash flows was primarily due to the following:

- $61.3 million additional cash provided from short-term debt borrowings.
- $7.7 million increase in cash flows due to lower repayments of long-term debt. In the current-year quarter, we repaid $2.3 million of long-term debt compared to $10.0 million in the prior-year quarter.

These increases in financing cash flows were partially offset by the following:

- $12.5 million additional cash used to repurchase common stock as part of our share buyback program.
- $7.2 million less cash received from proceeds related to the issuance of common stock.

The following table summarizes our share issuances for the three months ended December 31, 2011 and 2010.

	Three Months Ended December 31	
	2011	**2010**
Shares issued:		
1998 Long-Term Incentive Plan	197,503	595,103
Outside Directors Stock-for-Fee Plan	618	638
Total shares issued	198,121	595,741

The quarter-over-quarter decrease in the number of shares issued primarily reflects the significant number of stock options exercised in the prior year. During the current quarter, we cancelled and retired 99,555 shares attributable to federal withholdings on equity awards and repurchased and retired 387,991 shares through our 2011 share repurchase program described in Note 7.

As of September 30, 2011, we were authorized to grant awards for up to a maximum of 6.5 million shares of common stock under our 1998 Long-Term Incentive Plan (LTIP). In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings reach their highest levels in the winter months.

We finance our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and four committed revolving credit facilities with third-party lenders that provide approximately $1.0 billion of working capital funding. As of December 31, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was $499.2 million.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At December 31, 2011, $900

million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

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 regulated and nonregulated 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). As of December 31, 2011, all three ratings agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa1	A-
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

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 independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2011. Our debt covenants are described in greater detail in Note 6 to the unaudited condensed consolidated financial statements.

Capitalization

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2011, September 30, 2011 and December 31, 2010:

	December 31, 2011		September 30, 2011		December 31, 2010	
	(In thousands, except percentages)					
Short-term debt	$ 389,985	8.0%	$ 206,396	4.4%	$ 247,993	5.3%
Long-term debt	2,206,324	45.4%	2,208,551	47.3%	2,159,753	46.1%
Shareholders' equity	2,267,762	46.6%	2,255,421	48.3%	2,274,853	48.6%
Total	$4,864,071	100.0%	$4,670,368	100.0%	$4,682,599	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 53.4 percent at December 31, 2011, 51.7 percent at September 30, 2011 and 51.4 percent at December 31, 2010. Our ratio of total debt to capitalization is typically greater during the winter heating season as we incur short-term debt to fund natural gas purchases and meet our working capital requirements. We intend to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 9 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2011.

Risk Management Activities

We conduct risk management activities through our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases.

In our nonregulated 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 instruments, 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 financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three months ended December 31, 2011 and 2010:

	Three Months Ended December 31	
	2011	2010
	(In thousands)	
Fair value of contracts at beginning of period	$(79,277)	$ (49,600)
Contracts realized/settled	(17,729)	(32,981)
Fair value of new contracts	(555)	531
Other changes in value	11,732	108,856
Fair value of contracts at end of period	$(85,829)	$ 26,806

The fair value of our natural gas distribution segment's financial instruments at December 31, 2011 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2011				
	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	$(15,904)	$(69,925)	$—	$—	$(85,829)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(15,904)	$(69,925)	$—	$—	$(85,829)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three months ended December 31, 2011 and 2010:

	Three Months Ended December 31	
	2011	2010
	(In thousands)	
Fair value of contracts at beginning of period	$(25,050)	$(12,374)
Contracts realized/settled	17,449	934
Fair value of new contracts	—	—
Other changes in value	(7,662)	759
Fair value of contracts at end of period	(15,263)	(10,681)
Netting of cash collateral	22,084	25,296
Cash collateral and fair value of contracts at period end	$ 6,821	$ 14,615

The fair value of our nonregulated segment's financial instruments at December 31, 2011 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2011				
	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	$(15,975)	$734	$(22)	$—	$(15,263)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(15,975)	$734	$(22)	$—	$(15,263)

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2011 and 2010, our total net periodic pension and other benefits cost was $17.3 million and $14.9 million. Those costs relating to our natural gas distribution operations are generally recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2012 costs were determined using a September 30, 2011 measurement date. As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates, were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Accordingly, our fiscal 2012 pension and postretirement medical costs for the quarter ended December 31, 2011 were higher than the prior-year quarter.

The amounts with which we fund our defined benefit plans are determined in accordance with the Pension Protection Act of 2006 (PPA) and are influenced by the funded position of the plans when the funding requirements are determined on January 1 of each year. Based upon the most recent evaluation, we anticipate contributing between $25 million and $30 million to our defined benefit plans in fiscal 2012. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold. With respect to our postretirement medical plans, we anticipate contributing between $20 million and $25 million to these plans during fiscal 2012.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts will be determined by actual investment returns, changes in interest rates, values of assets in the plan and changes in the demographic composition of the participants in the plan.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three-month periods ended December 31, 2011 and 2010.

Natural Gas Distribution Sales and Statistical Data — Continuing Operations

	Three Months Ended December 31	
	2011	**2010**
METERS IN SERVICE, end of period		
Residential	2,847,305	2,848,433
Commercial	258,749	261,494
Industrial	2,318	2,328
Public authority and other	10,253	10,158
Total meters	3,118,625	3,122,413
INVENTORY STORAGE BALANCE — Bcf[1]	58.1	55.6
SALES VOLUMES — MMcf [2]		
Gas sales volumes		
Residential	50,240	50,156
Commercial	26,604	26,029
Industrial	5,412	5,146
Public authority and other	2,634	2,806
Total gas sales volumes	84,890	84,137
Transportation volumes	33,967	33,217
Total throughput	118,857	117,354
OPERATING REVENUES (000's)[2]		
Gas sales revenues		
Residential	$ 437,509	$ 443,639
Commercial	189,688	189,265
Industrial	26,707	28,689
Public authority and other	17,494	18,537
Total gas sales revenues	671,398	680,130
Transportation revenues	14,862	15,691
Other gas revenues	7,032	7,641
Total operating revenues	$ 693,292	$ 703,462
Average transportation revenue per Mcf[1]	$ 0.44	$ 0.48
Average cost of gas per Mcf sold[1]	$ 4.78	$ 4.92

See footnote following these tables.

Natural Gas Distribution Sales and Statistical Data — Discontinued Operations

	Three Months Ended December 31	
	2011	2010
Meters in service, end of period	84,383	83,873
Sales volumes — MMcf		
Total gas sales volumes	2,429	2,653
Transportation volumes	1,597	1,536
Total throughput	4,026	4,189
Operating revenues (000's)	$23,451	$23,733

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended December 31	
	2011	2010
CUSTOMERS, end of period		
Industrial	771	749
Municipal	69	62
Other	516	512
Total	1,356	1,323
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	27.9	22.1
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[(2)]	160,829	153,178
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[(2)]	106,462	107,712
OPERATING REVENUES (000's)[(2)]		
Regulated transmission and storage	$ 56,759	$ 49,007
Nonregulated	444,176	475,640
Total operating revenues	$500,935	$524,647

Note to preceding tables:

(1) Statistics are shown on a consolidated basis.

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. During the three months ended December 31, 2011, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure

controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

During the three months ended December 31, 2011, except as noted in Note 9 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 13 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2011. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

On September 28, 2011, the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company. As of December 31, 2011, 387,991 shares had been repurchased.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2011 to October 31, 2011	—	$ —	—	5,000,000
November 1, 2011 to November 30, 2011	77,818	32.51	77,818	4,922,182
December 1, 2011 to December 31, 2011	310,173	32.26	310,173	4,612,009
Total	387,991	$32.31	387,991	4,612,009

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.

SIGNATURE

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/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: February 8, 2012

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.1	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2012	
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*	
101.INS	XBRL Instance Document**	
101.SCH	XBRL Taxonomy Extension Schema**	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase**	
101.DEF	XBRL Taxonomy Extension Definition Linkbase**	
101.LAB	XBRL Taxonomy Extension Labels Linkbase**	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase**	

* 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.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.