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

Form 10-K

(Mark One)

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

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, No Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 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 been phased into the interactive data requirements.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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 Act). Yes ☐ No ☑

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2009, was $2,072,764,690.

As of November 8, 2009, the registrant had 92,599,896 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 3, 2010 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
APS	Atmos Pipeline and Storage, LLC
ATO	Trading symbol for Atmos Energy Corporation common stock on the New York Stock Exchange
Bcf	Billion cubic feet
COSO	Committee of Sponsoring Organizations of the Treadway Commission
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
KPSC	Kentucky Public Service Commission
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
MMcf	Million cubic feet
Moody's	Moody's Investor Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
Settled Cities	Represents 438 of the 439 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.
SRF	Stable Rate Filing
TXU Gas	TXU Gas Company, which was acquired on October 1, 2004
WNA	Weather Normalization Adjustment

PART I

The terms "we," "our," "us", "Atmos Energy" and the "Company" refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise.

ITEM 1. *Business.*

Overview and Strategy

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. Since our incorporation in Texas in 1983, we have grown primarily through a series of acquisitions, the most recent of which was the acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company. We are also incorporated in the state of Virginia.

Today, we distribute natural gas through regulated sales and transportation arrangements to over 3 million residential, commercial, public authority and industrial customers in 12 states located primarily in the South, which makes us one of the country's largest natural-gas-only distributors based on number of customers. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

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 along with storage services to certain of our natural gas distribution divisions and third parties.

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while operating our regulated and nonregulated businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

We have experienced more than 25 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. Historically, we achieved this record of growth through acquisitions while efficiently managing our operating and maintenance expenses and leveraging our technology to achieve more efficient operations. In recent years, we have also achieved growth by implementing rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns. In addition, we have developed various commercial opportunities within our regulated transmission and storage operations. Finally, we have strengthened our nonregulated businesses by increasing sales volumes and improving per-unit margins.

Our core values include focusing on our employees and customers while conducting our business with honesty and integrity. We continue to strengthen our culture through ongoing communications with our employees and enhanced employee training.

Operating Segments

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 is comprised of our nonregulated natural gas gathering, transmission and storage services.

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

Our natural gas distribution segment consists of the following six regulated divisions, presented in order of total customers served, covering service areas in 12 states:

- Atmos Energy Mid-Tex Division,
- Atmos Energy Kentucky/Mid-States Division,
- Atmos Energy Louisiana Division,
- Atmos Energy West Texas Division,
- Atmos Energy Mississippi Division and
- Atmos Energy Colorado-Kansas Division

Our natural gas distribution business is a seasonal business. Gas sales to residential and commercial customers are greater during the winter months than during the remainder of the year. The volumes of gas sales during the winter months will vary with the temperatures during these months.

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, we transport natural gas for others through our distribution system.

Rates established by regulatory authorities often include cost adjustment mechanisms for costs that (i) are subject to significant price fluctuations compared to our other costs, (ii) represent a large component of our cost of service and (iii) are generally outside our control.

Purchased gas cost mechanisms represent a common form of cost adjustment mechanism. Purchased gas cost adjustment mechanisms provide natural gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in natural gas distribution gas costs. Therefore, although substantially all of our natural gas distribution operating revenues fluctuate with the cost of gas that we purchase, natural gas distribution gross profit (which is defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas.

Additionally, some jurisdictions have introduced performance-based ratemaking adjustments to provide incentives to natural gas utilities to minimize purchased gas costs through improved storage management and use of financial instruments to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

Finally, regulatory authorities have approved weather normalization adjustments (WNA) for over 90 percent of residential and commercial meters in our service areas as a part of our rates. WNA minimizes the effect of weather that is above or below normal by allowing us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal.

As of September 30, 2009 we had WNA for our residential and commercial meters in the following service areas for the following 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

Financial results for this segment are affected by the cost of natural gas and economic conditions in the areas that we serve. As discussed above, we are generally able to pass the cost of gas through to our customers under purchased gas adjustment clauses; therefore, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs may cause customers to conserve or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

Our supply of natural gas is provided by a variety of suppliers, including independent producers, marketers and pipeline companies and withdrawals of gas from proprietary and contracted storage assets. Additionally, the natural gas supply for our Mid-Tex Division includes peaking and spot purchase agreements.

Supply arrangements consist of both base load and swing supply (peaking) quantities and are contracted from our suppliers on a firm basis with various terms at market prices. Base load quantities are those that flow at a constant level throughout the month and swing supply quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions.

Currently, all of our natural gas distribution divisions, except for our Mid-Tex Division, utilize 39 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have "pipeline no-notice" storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered by our Atmos Pipeline — Texas Division.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest cost. Major suppliers during fiscal 2009 were Anadarko Energy Services, Chesapeake Energy Marketing, Inc., ConocoPhillips Company, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., Iberdrola Renewables, Inc., National Fuel Marketing Company, LLC, ONEOK Energy Services Company L.P., Tenaska Marketing and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary.

The combination of base load, peaking and spot purchase agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments. We estimate our peak-day availability of natural gas supply to be approximately 4.2 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2009 was on January 15, 2009, when sales to customers reached approximately 3.1 Bcf.

To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts or applicable state regulations or statutes. Our customers' demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers. We anticipate no problems with obtaining additional gas supply as needed for our customers.

The following briefly describes our six natural gas distribution divisions. We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2009, we held 1,111 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire. Additional information concerning our natural gas distribution divisions is presented under the caption "Operating Statistics".

Atmos Energy Mid-Tex Division. Our Mid-Tex Division serves approximately 550 incorporated and unincorporated communities in the north-central, eastern and western parts of Texas, including the Dallas/Fort Worth Metroplex. The governing body of each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. The Railroad Commission of Texas (RRC) has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality.

Prior to fiscal 2008, this division operated under one system-wide rate structure. However, in 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers (Settled Cities) that has allowed us, beginning in 2008, to update rates for customers in these cities through an annual rate review mechanism. Rates for the remaining 20 percent of this division's customers, primarily the City of Dallas, continue to be updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). 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.

Atmos Energy Kentucky/Mid-States Division. Our Kentucky/Mid-States Division operates in more than 420 communities across Georgia, Illinois, Iowa, Kentucky, Missouri, Tennessee and Virginia. The service areas in these states are primarily rural; however, this division serves Franklin, Tennessee, and other suburban areas of Nashville. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

Atmos Energy Louisiana Division. In Louisiana, we serve nearly 300 communities, including the suburban areas of New Orleans, the metropolitan area of Monroe and western Louisiana. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our natural gas marketing segment. Our rates in this division are updated annually through a rate stabilization clause filing without filing a formal rate case.

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. However, the West Texas Division entered into agreements with its West Texas service areas during 2008 and its Amarillo and Lubbock service area during 2009 to update rates for customers in these service areas through an annual rate review mechanism.

Atmos Energy Mississippi Division. In Mississippi, we serve about 110 communities throughout the northern half of the state, including the Jackson metropolitan area. Our rates in the Mississippi Division are updated annually through a stable rate filing without filing a formal rate case.

Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division serves approximately 170 communities throughout Colorado and Kansas and parts of Missouri, including the cities of Olathe, Kansas, a suburb of Kansas City and Greeley, Colorado, located near Denver. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

The following table provides a jurisdictional rate summary for our regulated operations. This information is for regulatory purposes only and may not be representative of our actual financial position.

Division	Jurisdiction	Effective Date of Last Rate/GRIP Action	Rate Base (thousands)[1]	Authorized Rate of Return[1]	Authorized Return on Equity[1]
Atmos Pipeline — Texas	Texas	5/24/04	$417,111	8.258%	10.00%
Atmos Pipeline — Texas — GRIP	Texas	4/28/09	755,038	8.258%	10.00%
Colorado-Kansas	Colorado	10/1/07	81,208	8.45%	11.25%
	Kansas	5/12/08	(2)	(2)	(2)
Kentucky/Mid-States	Georgia	9/22/08	66,893	7.75%	10.70%
	Illinois	11/1/00	24,564	9.18%	11.56%
	Iowa	3/1/01	5,000	(2)	11.00%
	Kentucky	8/1/07	(2)	(2)	(2)
	Missouri	3/4/07	(2)	(2)	(2)
	Tennessee	4/1/09	190,100	8.24%	10.30%
	Virginia	9/30/08	33,194	8.46% - 8.96%	9.50% - 10.50%
Louisiana	Trans LA	4/1/09	96,570	(2)	10.00% - 10.80%
	LGS	7/1/09	236,600	(2)	10.40%
Mid-Tex — Settled Cities	Texas	8/1/09	1,262,969[3]	7.78%	9.60%
Mid-Tex — Dallas & Environs	Texas	6/24/08	1,127,924[3]	7.98%	10.00%
Mississippi	Mississippi	1/1/05	196,801	8.23%	9.80%
West Texas	Amarillo	9/1/03	36,844	9.88%	12.00%
	Lubbock	3/1/04	43,300	9.15%	11.25%
	West Texas	8/1/09	124,401	(2)	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider[4]	WNA	Performance-Based Rate Program[5]	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	54/46	No[7]	No	No	111,382
	Kansas	(2)	Yes	Yes	No	129,983
Kentucky/Mid-States	Georgia	55/45	No	Yes	Yes	65,080
	Illinois	67/33	No	No	No	22,623
	Iowa	57/43	No	No	No	4,344
	Kentucky	(2)	No[7]	Yes	Yes	175,789
	Missouri	(2)	No	No[6]	No	57,332
	Tennessee	52/48	Yes	Yes	Yes	132,764
	Virginia	55/45	Yes	Yes	No	23,182
Louisiana	Trans LA	52/48	No	Yes	No	78,345
	LGS	52/48	No	Yes	No	277,648
Mid-Tex — Settled Cities	Texas	52/48	Yes	Yes	No	1,227,598
Mid-Tex — Dallas & Environs	Texas	52/48	Yes	Yes	No	306,899
Mississippi	Mississippi	47/53	No[7]	Yes	No	266,785
West Texas	Amarillo	50/50	Yes	Yes	No	69,836
	Lubbock	50/50	Yes	Yes	No	73,642
	West Texas	52/48	Yes	Yes	No	155,612

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the last rate case or GRIP filing for each jurisdiction. These rate bases, rates of return and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity.

(2) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.

(3) The Mid-Tex Rate Base amounts for the Settled Cities and Dallas and Environs both represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base. The difference in rate base amounts is due to two separate test filing periods covered.

(4) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.

(5) The performance-based rate program provides incentives to natural gas utility companies to minimize purchased gas costs by allowing the utility company and its customers to share the purchased gas costs savings.

(6) The Missouri jurisdiction has a straight-fixed variable rate design which decouples gross profit margin from customer usage patterns.

(7) The Company has pending requests in Colorado, Kentucky and Mississippi to move bad debt cost to the gas cost recovery mechanism. A hearing regarding the Mississippi request was held on September 1, 2009.

Natural Gas Distribution Sales and Statistical Data

	Fiscal Year Ended September 30				
	2009	**2008**	**2007**	**2006**	**2005**
METERS IN SERVICE, end of year					
Residential	2,901,577	2,911,475	2,893,543	2,886,042	2,862,822
Commercial	265,843	268,845	272,081	275,577	274,536
Industrial	2,193	2,241	2,339	2,661	2,715
Public authority and other	9,231	9,218	19,164	16,919	17,767
Total meters	3,178,844	3,191,779	3,187,127	3,181,199	3,157,840
INVENTORY STORAGE BALANCE — Bcf	57.0	58.3	58.0	59.9	54.7
HEATING DEGREE DAYS[1]					
Actual (weighted average)	2,713	2,820	2,879	2,527	2,587
Percent of normal	100%	100%	100%	87%	89%
SALES VOLUMES — MMcf[2]					
Gas Sales Volumes					
Residential	159,762	163,229	166,612	144,780	162,016
Commercial	91,379	93,953	95,514	87,006	92,401
Industrial	18,563	21,734	22,914	26,161	29,434
Public authority and other	12,413	13,760	12,287	14,086	12,432
Total gas sales volumes	282,117	292,676	297,327	272,033	296,283
Transportation volumes	130,691	141,083	135,109	126,960	122,098
Total throughput	412,808	433,759	432,436	398,993	418,381
OPERATING REVENUES (000's)[2]					
Gas Sales Revenues					
Residential	$1,830,140	$2,131,447	$1,982,801	$2,068,736	$1,791,172
Commercial	838,184	1,077,056	970,949	1,061,783	869,722
Industrial	135,633	212,531	195,060	276,186	229,649
Public authority and other	89,183	137,821	114,298	144,600	114,742
Total gas sales revenues	2,893,140	3,558,855	3,263,108	3,551,305	3,005,285
Transportation revenues	59,914	60,504	59,813	62,215	59,996
Other gas revenues	31,711	35,771	35,844	37,071	37,859
Total operating revenues	$2,984,765	$3,655,130	$3,358,765	$3,650,591	$3,103,140
Average transportation revenue per Mcf	$ 0.46	$ 0.43	$ 0.44	$ 0.49	$ 0.49
Average cost of gas per Mcf sold	$ 6.95	$ 9.05	$ 8.09	$ 10.02	$ 7.41
Employees	4,691	4,558	4,472	4,402	4,327

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data By Division

	Fiscal Year Ended September 30, 2009							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado- Kansas	Other[3]	Total
METERS IN SERVICE								
Residential	1,417,869	423,829	333,224	270,757	237,289	218,609	—	2,901,577
Commercial	116,480	53,386	22,769	24,986	26,142	22,080	—	265,843
Industrial	148	909	—	508	532	96	—	2,193
Public authority and other	—	2,555	—	2,839	2,822	1,015	—	9,231
Total	1,534,497	480,679	355,993	299,090	266,785	241,800	—	3,178,844
HEATING DEGREE DAYS[1]								
Actual	2,036	3,853	1,574	3,553	2,746	5,520	—	2,713
Percent of normal	100%	98%	101%	99%	103%	100%	—	100%
SALES VOLUMES — MMcf[2]								
Gas Sales Volumes								
Residential	73,678	26,589	12,371	16,341	13,503	17,280	—	159,762
Commercial	48,363	16,049	6,771	6,780	6,568	6,848	—	91,379
Industrial	2,918	6,217	—	3,528	5,704	196	—	18,563
Public authority and other	—	1,434	—	6,014	2,901	2,064	—	12,413
Total	124,959	50,289	19,142	32,663	28,676	26,388	—	282,117
Transportation volumes	44,991	41,693	5,151	23,417	4,968	10,471	—	130,691
Total throughput	169,950	91,982	24,293	56,080	33,644	36,859	—	412,808
OPERATING MARGIN (000's)[2]	$ 483,155	$163,602	$118,021	$ 89,982	$ 91,680	$ 78,188	$ —	$1,024,628
OPERATING EXPENSES (000's)[2]								
Operation and maintenance	$ 150,978	$ 68,823	$ 41,956	$ 35,126	$ 43,642	$ 32,935	$ (4,031)	$ 369,429
Depreciation and amortization	$ 94,040	$ 32,755	$ 22,492	$ 15,242	$ 12,411	$ 15,334	$ —	$ 192,274
Taxes, other than income	$ 108,412	$ 13,261	$ 9,629	$ 15,863	$ 13,925	$ 8,222	$ —	$ 169,312
Asset impairments	$ 2,100	$ 785	$ 510	$ 413	$ 415	$ 376	$ —	$ 4,599
OPERATING INCOME (000's)[2]	$ 127,625	$ 47,978	$ 43,434	$ 23,338	$ 21,287	$ 21,321	$ 4,031	$ 289,014
CAPITAL EXPENDITURES (000's)	$ 173,201	$ 57,943	$ 42,626	$ 33,960	$ 22,173	$ 24,726	$ 24,871	$ 379,500
PROPERTY, PLANT AND EQUIPMENT, NET (000's)	$1,615,900	$722,530	$390,957	$299,242	$266,053	$284,398	$124,391	$3,703,471
OTHER STATISTICS, at year end								
Miles of pipe	28,996	12,158	8,321	7,702	6,540	7,162	—	70,879
Employees	1,585	605	446	352	389	290	1,024	4,691

See footnotes following these tables.

	Fiscal Year Ended September 30, 2008							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado-Kansas	Other[3]	Total
METERS IN SERVICE								
Residential	1,414,543	431,880	336,211	270,990	240,113	217,738	—	2,911,475
Commercial	117,022	54,538	23,059	25,226	27,219	21,781	—	268,845
Industrial	163	930	—	497	562	89	—	2,241
Public authority and other	—	2,563	—	2,888	2,822	945	—	9,218
Total	1,531,728	489,911	359,270	299,601	270,716	240,553	—	3,191,779
HEATING DEGREE DAYS[1]								
Actual	2,213	3,799	1,531	3,546	2,741	5,861	—	2,820
Percent of normal	99%	96%	99%	99%	101%	105%	—	100%
SALES VOLUMES — MMcf[2]								
Gas Sales Volumes								
Residential	76,296	26,009	12,475	17,190	12,882	18,377	—	163,229
Commercial	50,348	15,731	6,858	7,162	6,590	7,264	—	93,953
Industrial	3,293	7,740	—	3,876	6,580	245	—	21,734
Public authority and other	—	1,419	—	6,933	3,013	2,395	—	13,760
Total	129,937	50,899	19,333	35,161	29,065	28,281	—	292,676
Transportation volumes	49,606	44,796	6,136	26,411	4,219	9,915	—	141,083
Total throughput	179,543	95,695	25,469	61,572	33,284	38,196	—	433,759
OPERATING MARGIN (000's)[2]	$ 478,622	$159,265	$110,754	$ 87,344	$ 91,749	$ 78,332	$ —	$1,006,066
OPERATING EXPENSES (000's)[2]								
Operation and maintenance	$ 167,497	$ 65,161	$ 42,367	$ 36,688	$ 46,024	$ 35,414	$ (3,907)	$ 389,244
Depreciation and amortization	$ 84,202	$ 30,574	$ 21,193	$ 14,781	$ 11,752	$ 14,703	$ —	$ 177,205
Taxes, other than income	$ 111,914	$ 14,799	$ 8,104	$ 22,032	$ 14,003	$ 7,600	$ —	$ 178,452
OPERATING INCOME (000's)[2]	$ 115,009	$ 48,731	$ 39,090	$ 13,843	$ 19,970	$ 20,615	$ 3,907	$ 261,165
CAPITAL EXPENDITURES (000's)	$ 178,409	$ 59,274	$ 46,674	$ 34,354	$ 22,590	$ 20,331	$ 24,910	$ 386,542
PROPERTY, PLANT AND EQUIPMENT, NET (000's)	$1,491,188	$689,109	$370,751	$278,326	$254,452	$272,121	$127,609	$3,483,556
OTHER STATISTICS, at year end								
Miles of pipe	28,697	12,104	8,277	14,697	6,537	7,150	—	77,462
Employees	1,506	635	427	342	393	281	974	4,558

Notes to preceding tables:

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

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

(3) The Other column represents our shared services function, which provides administrative and other support to the Company. Certain costs incurred by this function are not allocated.

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, 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. Gross profit earned from our Mid-Tex Division and through certain other transportation and storage services is subject to traditional ratemaking governed by the RRC. However, Atmos Pipeline — Texas' existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates with minimal regulation.

These operations include one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Nine basins located in Texas are believed to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins.

Regulated Transmission and Storage Sales and Statistical Data

	Fiscal Year Ended September 30				
	2009	**2008**	**2007**	**2006**	**2005**
CUSTOMERS, end of year					
Industrial	68	62	65	67	66
Other	168	189	196	178	191
Total	236	251	261	245	257
PIPELINE TRANSPORTATION VOLUMES — MMcf[(1)]	706,132	782,876	699,006	581,272	554,452
OPERATING REVENUES (000's)[(1)]	$209,658	$195,917	$163,229	$141,133	$142,952
Employees, at year end	62	60	54	85	78

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

Natural Gas Marketing Segment Overview

Our natural gas marketing activities are conducted through Atmos Energy Marketing (AEM), which is wholly-owned by Atmos Energy Holdings, Inc. (AEH). AEH is a wholly-owned subsidiary of AEC and operates primarily in the Midwest and Southeast areas of the United States.

AEM's 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. AEM serves most of its customers under contracts generally having one to two year terms and sells natural gas to some of its industrial customers on a delivered burner tip basis under contract terms ranging from 30 days to two years. 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 maximize, 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.

Natural Gas Marketing Sales and Statistical Data

	Fiscal Year Ended September 30				
	2009	2008	2007	2006	2005
CUSTOMERS, end of year					
Industrial	631	624	677	679	559
Municipal	63	55	68	73	69
Other	321	312	281	289	211
Total	1,015	991	1,026	1,041	839
INVENTORY STORAGE BALANCE — Bcf	17.0	11.0	19.3	15.3	8.2
NATURAL GAS MARKETING SALES VOLUMES — MMcf[1]	441,081	457,952	423,895	336,516	273,201
OPERATING REVENUES (000's)[1]	$2,336,847	$4,287,862	$3,151,330	$3,156,524	$2,106,278

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

Pipeline, Storage and Other Segment Overview

Our pipeline, storage and other segment primarily consists of the operations of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. 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. It also owns or controls additional pipeline and storage capacity including interests 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.

APS' primary business is to provide storage and transportation services to our Louisiana and Kentucky/MidStates regulated natural gas distribution divisions, to our natural gas marketing segment and, on a more limited basis, to third parties. APS earns transportation fees and storage demand charges to aggregate and provide gas supply, provide access to storage capacity and transport gas for these customers.

APS also engages in various asset optimization activities. APS' primary asset optimization activity involves the administration of two asset management plans with regulated affiliates of the Company. These arrangements provide APS the opportunity to maximize the economic value associated with the transportation and storage capacity assigned to these plans. APS attempts to meet this objective through a variety of activities including engaging in natural gas storage transactions and utilizing excess asset capacity to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. These plans require APS to share a portion of the economic value created by these activities with the regulated customers served by these affiliates. These arrangements have been approved by applicable state regulatory commissions and are subject to annual regulatory review intended to ensure proper allocation of economic value between our regulated customers and APS.

APS also seeks to maximize the economic value associated with the storage and transportation capacity it owns or controls. 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 APS has access and, in transactions involving storage capacity, selling financial instruments at advantageous prices to lock in a gross profit margin.

Pipeline, Storage and Other Sales and Statistical Data

	Fiscal Year Ended September 30				
	2009	2008	2007	2006	2005
OPERATING REVENUES (000's)[(1)]	$41,924	$31,709	$33,400	$25,574	$15,639
PIPELINE TRANSPORTATION VOLUMES — MMcf[(1)]	6,395	5,492	7,710	9,712	7,593
INVENTORY STORAGE BALANCE — Bcf	2.9	1.4	2.0	2.6	1.8

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

Ratemaking Activity

Overview

The method of determining regulated rates varies among the states in which our natural gas distribution divisions operate. The regulatory authorities have the responsibility of ensuring that utilities in their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on their investment. Generally, each regulatory authority reviews rate requests and establishes a rate structure intended to generate revenue sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital.

Our current rate strategy is to focus on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins. Atmos Energy has annual ratemaking mechanisms in place in three states that provide for an annual rate review and adjustment to rates for approximately 68 percent of our customers. Additionally, we have WNA mechanisms in eight states. These mechanisms work in tandem to provide insulation from volatile margins, both for the Company and our customers.

We will also continue to address various rate design changes, including the recovery of bad debt gas costs, inclusion of other taxes in gas costs and stratification of rates to benefit low income households in future rate filings. These design changes would address cost variations that are related to pass-through energy costs beyond our control.

Although substantial progress has been made in recent years by improving rate design across Atmos' operating area, potential changes in federal energy policy and adverse economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Substantially all of our natural gas distribution revenues in the fiscal years ended September 30, 2009, 2008 and 2007 were derived from sales at rates set by or subject to approval by local or state authorities. Annual net operating income increases resulting from ratemaking activity totaling $54.4 million, $40.6 million, and $45.2 million became effective in fiscal 2009, 2008 and 2007 as summarized below:

	Annual Increase (Decrease) to Operating Income For the Fiscal Year Ended September 30		
Rate Action	**2009**	**2008**	**2007**
		(In thousands)	
Rate case filings	$ 2,959	$27,838	$ 7,793
GRIP filings	11,443	8,101	25,624
Annual rate filing mechanisms	38,764	3,275	12,963
Other rate activity	1,237	1,424	(1,132)
	$54,403	$40,638	$45,248

Additionally, the following ratemaking efforts were initiated during fiscal 2009 but had not been completed as of September 30, 2009:

Division	**Rate Action**	**Jurisdiction**	**Operating Income Requested**
			(In thousands)
Mid-Tex	Rate Case[(1)]	Dallas & Environs	$ 7,743
Colorado/Kansas	Rate Case	Colorado	3,834
	GSRS[(2)]	Kansas	766
Kentucky/Mid-States	Rate Case[(3)]	Virginia	1,677
	PRP Surcharge[(4)]	Georgia	909
West Texas	Rate Review Mechanism[(5)]	Lubbock	3,476
	Rate Review Mechanism[(5)]	Amarillo	2,285
Mississippi	Stable Rate Filing	Mississippi	10,195
			$30,885

(1) Texas Railroad Commission Examiners issued a proposal for decision (PFD) on October 9, 2009. The PFD recommended a rate change of $3.5 million applicable to the Dallas and Environs area of the Mid-Tex system. The Company has filed exceptions to the Examiner's proposal. A final Commission decision is expected before the end of the year.

(2) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

(3) The Company filed a Rate Case with the state of Virginia requesting a $1.7 million increase. The staff has recommended an increase of $1.4 million.

(4) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(5) The Company filed Rate Review Mechanisms with the City of Lubbock requesting an increase of $3.5 million and with the City of Amarillo requesting an increase of $2.3 million. Effective October 1, 2009, the respective cities have approved increases of $2.7 million and $1.3 million.

In October 2009, we filed rate cases in Georgia and Kentucky, requesting an increase in operating income of $3.8 million and $9.5 million.

Our recent ratemaking activity is discussed in greater detail below.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to 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 (Decrease) in Annual Operating Income (In thousands)	Effective Date
2009 Rate Case Filings:			
Kentucky/Mid-States	Tennessee	$ 2,513	4/1/09
West Texas	Texas	446	Various
Total 2009 Rate Case Filings		$ 2,959	
2008 Rate Case Filings:			
Kentucky/Mid-States	Virginia	$ 869	9/30/08
Kentucky/Mid-States	Georgia	3,351	9/22/08
Mid-Tex(1)	Texas	5,430	6/24/08
Colorado-Kansas	Kansas	2,100	5/12/08
Mid-Tex(2)	Texas	8,000	4/1/08
Kentucky/Mid-States	Tennessee	8,088	11/4/07
Total 2008 Rate Case Filings		$27,838	
2007 Rate Case Filings:			
Kentucky/Mid-States	Kentucky(3)	$ 6,200	8/1/07
Mid-Tex	Texas(4)	4,793	4/1/07
Kentucky/Mid-States	Missouri(5)	1,500	3/4/07
Kentucky/Mid-States	Tennessee	(4,700)	12/15/06
Total 2007 Rate Case Filings		$ 7,793	

(1) Increase relates only to the City of Dallas and Environs areas of the Mid-Tex Division.

(2) Increase relates only to the Settled Cities area of the Mid-Tex Division.

(3) In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. In June 2007, the KPSC issued an order dismissing the case. In December 2006, the Company filed a rate application for an increase in base rates. Additionally, we proposed to implement a process to review our rates annually and to collect the bad debt portion of gas costs directly rather than through the base rate. In July 2007, the KPSC approved a settlement we had reached with the Attorney General for an increase in annual operating income of $6.2 million effective August 1, 2007.

(4) In March 2007, the RRC issued an order, which increased the Mid-Tex Division's annual operating income by approximately $4.8 million beginning April 2007 and established a permanent WNA based on 10-year average weather effective for the months of November through April of each year. The RRC also approved a cost allocation method that eliminated a subsidy received from industrial and transportation customers and increased the revenue responsibility for residential and commercial customers. However, the order also required an immediate refund of amounts collected from our 2003 — 2005 GRIP filings of approximately

$2.9 million and reduced our total return to 7.903 percent from 8.258 percent, based on a capital structure of 48.1 percent equity and 51.9 percent debt with a return on equity of 10 percent.

(5) The Missouri Commission issued an order in March 2007 approving a settlement with rate design changes, including revenue decoupling through the recovery of all non-gas cost revenues through fixed monthly charges and an estimated increase in operating income of $1.5 million.

GRIP Filings

As discussed above in "Natural Gas Distribution Segment Overview," GRIP allows natural gas utility companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. The following table summarizes our GRIP filings with effective dates during the fiscal years ended September 30, 2009, 2008 and 2007:

Division	Calendar Year	Incremental Net Utility Plant Investment	Additional Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2009 GRIP:				
Mid-Tex[1]	2007	$ 57,385	$ 1,837	1/26/09
West Texas[2]	2007/08	27,425	532	Various
Atmos Pipeline — Texas	2008	51,308	6,342	4/28/09
Mid-Tex[3]	2008	105,777	2,732	9/9/09
Total 2009 GRIP		$241,895	$11,443	
2008 GRIP:				
Atmos Pipeline — Texas	2007	$ 46,648	$ 6,970	4/15/08
West Texas	2006	7,022	1,131	12/17/07
Total 2008 GRIP		$ 53,670	$ 8,101	
2007 GRIP:				
Atmos Pipeline — Texas	2006	$ 88,938	$13,202	9/14/07
Mid-Tex	2006	62,375	12,422	9/14/07
Total 2007 GRIP		$151,313	$25,624	

(1) Increase relates to the City of Dallas and Environs areas of the Mid-Tex Division.

(2) The West Texas Division files GRIP applications related only to the Lubbock Environs and the West Texas Cities Environs. GRIP implemented for this division include investments that related to both calendar years 2007 and 2008. The incremental investment is based on system-wide plant and additional annual operating income is applicable to Environs customers only.

(3) Increase relates only to the City of Dallas area of the Mid-Tex Division.

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. As discussed above in "Natural Gas Distribution Segment Overview," 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 rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms:

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income (In thousands)	Effective Date
2009 Filings:				
Louisiana	LGS	12/31/08	$ 3,307	7/1/09
Louisiana	Transla	9/30/08	611	4/1/09
Mississippi	Mississippi	6/30/08	—	N/A
Mid-Tex	Settled Cities	12/31/07	21,800	11/8/08
Mid-Tex	Settled Cities	12/31/08	1,979	8/1/09
West Texas	WT Cities	12/31/07	4,468	11/20/08
West Texas	WT Cities	12/31/08	6,599	8/1/09
Total 2009 Filings			$38,764	
2008 Filings:				
Louisiana	LGS	12/31/07	$ 1,709	7/1/08
Louisiana	Transla	9/30/07	1,566	4/1/08
Total 2008 Filings			$ 3,275	
2007 Filings:				
Mississippi	Mississippi	6/30/07	$ —	11/1/07
Louisiana	LGS	12/31/06	2,000	7/1/07
Louisiana	Transla	9/30/06	1,445	4/1/07
Louisiana	LGS	12/31/05	9,518	8/1/06
Total 2007 Filings			$12,963	

The rate review mechanism in the Mid-Tex Division was entered into as a result of a settlement in the September 20, 2007 Statement of Intent case filed with all Mid-Tex Division cities. Of the 439 incorporated cities served by the Mid-Tex Division, 438 of these cities are part of the rate review mechanism process. The West Texas rate review mechanism was entered into in August 2008 as a result of a settlement with the West Texas Coalition of Cities. The Lubbock and Amarillo rate review mechanisms were entered into in the spring of 2009. All mechanisms have been implemented on a three year trial period, of which three began in fiscal 2009, based upon calendar 2007 financial information and two of which began in fiscal 2009 based on 2008 financial information. The third rate review mechanism in the Mid-Tex Division will be filed in March 2010 based upon calendar 2009 financial information. This filing will be the last filing under the three year trial period.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2009, 2008 and 2007:

Division	Jurisdiction	Rate Activity	Increase (Decrease) in Operating Income (In thousands)	Effective Date
2009 Other Rate Activity:				
Kentucky/Mid-States	Georgia	PRP Surcharge(1)	$ 198	10/1/08
	Missouri	ISRS(2)	408	11/4/08
Colorado-Kansas	Kansas	Tax Surcharge(3)	631	2/1/09
Total 2009 Other Rate Activity			$ 1,237	
2008 Other Rate Activity:				
West Texas	Triangle	Special Contract	$ 748	6/1/08
Colorado-Kansas	Kansas	Tax Surcharge(3)	1,434	1/1/08
	Colorado	Agreement(4)	(1,100)	11/20/07
Kentucky/Mid-States	Georgia	PRP Surcharge(1)	342	10/1/07
Total 2008 Other Rate Activity			$ 1,424	
2007 Other Rate Activity:				
West Texas	Triangle	Special Contract	$ 227	7/1/07
Mid-Tex	Texas	GRIP Refund	(2,887)	4/1/07
Colorado-Kansas	Kansas	Tax Surcharge(3)	1,528	1/1/07
Total 2007 Other Rate Activity			$(1,132)	

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

(3) In the State of Kansas, the tax surcharge represents a true-up of ad valorem taxes paid versus what is designed to be recovered through base rates.

(4) In November 2007, the Colorado Public Utilities Commission approved an earnings agreement entered into jointly between the Colorado-Kansas Division, the Commission Staff and the Office of Consumer Counsel. The agreement called for a one-time refund to customers of $1.1 million made in January 2008.

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. 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 in GUD 9696 to examine the 36-month gas contract review process. In August 2009, the full Commission approved an order to eliminate the 36 month gas contract review at its August 2009 meeting.

Other Regulation

Each of our natural gas distribution divisions is regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our gas distribution facilities. In addition, our distribution operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with and are operated in substantial conformity with applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites in Tennessee, Iowa and Missouri.

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline — Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC. Additionally, the FERC has regulatory authority over the sale of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity, as well as authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are all necessary and appropriate steps to comply with these regulations.

In September 2008, the RRC issued a final rule requiring the replacement of known compression couplings at pre-bent gas meter risers by November 2009. This rule primarily affected the operations of the Mid-Tex Division. Compliance with this rule has required us to expend significant amounts of capital in the Mid-Tex Division, but these prudent and mandatory expenditures have been recoverable through our rates. As of September 30, 2009 we had substantially completed our pre-bent riser replacement program in the Mid-Tex Division.

Competition

Although our natural gas distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets. However, periods of higher gas prices, coupled with the electric utilities' marketing efforts, increase competition for residential and commercial customers. In addition, AEM competes with other natural gas marketers to provide natural gas management and other related services to customers.

Our regulated transmission and storage operations currently face limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers.

Employees

At September 30, 2009, we had 4,891 employees, consisting of 4,753 employees in our regulated operations and 138 employees in our nonregulated operations.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, and other forms that we file with or furnish to the Securities and Exchange Commission (SEC) are available free of charge at our website, *www.atmosenergy.com*, under "Publications and Filings" under the "Investors" tab, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address and telephone number appearing below:

Shareholder Relations
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
972-855-3729

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer, Robert W. Best, has certified to the New York Stock Exchange that he was not aware of any violation by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. *Risk Factors.*

Our financial and operating results are subject to a number of risk factors, many of which are not within our control. Although we have tried to discuss key risk factors below, please be aware that other or new risks may prove to be important in the future. Investors should carefully consider the following discussion of risk factors as well as other information appearing in this report. These factors include the following:

Further disruptions in the credit markets could limit our ability to access capital and increase our costs of capital.

We rely upon access to both short-term and long-term credit markets to satisfy our liquidity requirements. The global credit markets have experienced significant disruptions and volatility during the last two years to a greater degree than has been seen in decades. In some cases, the ability or willingness of traditional sources of capital to provide financing has been reduced.

Historically, we have accessed the commercial paper markets to finance our short-term working capital needs. The disruptions in the credit markets during the fall of 2008 temporarily limited our access to the commercial paper markets and increased our borrowing costs. Consequently, for a short period, we were forced to borrow directly under our primary credit facility that backstops our commercial paper program to provide much of our working capital. This credit facility provides up to $567 million in committed financing through its expiration in December 2011. Our borrowings under this facility, along with our commercial paper, have been used primarily to purchase natural gas supplies for the upcoming winter heating season. The amount of our working capital requirements in the near-term will depend primarily on the market price of natural gas. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facilities to fund our operations. The cost of both our borrowings under the primary credit facility and our commercial paper has increased significantly since September 2008. We have historically supplemented our commercial paper program with a short-term committed credit facility that must be renewed annually. No borrowings are currently outstanding under our current $200 million short-term facility, which matures in October 2010.

Our long-term debt is currently rated as “investment grade” by Standard & Poor’s Corporation, Moody’s Investors Services, Inc. and Fitch Ratings, Ltd. If adverse credit conditions were to cause a significant limitation on our access to the private and public credit markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the three credit rating agencies. Such a downgrade could further limit our access to public and/or private credit markets and increase the costs of borrowing under each source of credit.

Further, if our credit ratings were downgraded, we could be required to provide additional liquidity to our natural gas marketing segment because the commodity financial instruments markets could become unavailable to us. Our natural gas marketing segment depends primarily upon a committed $450 million credit facility to finance its working capital needs, which it uses primarily to issue standby letters of credit to its natural gas suppliers. A significant reduction in the availability of this facility could require us to provide extra liquidity to support its operations or reduce some of the activities of our natural gas marketing segment. Our ability to provide extra liquidity is limited by the terms of our existing lending arrangements with AEH, which are subject to annual approval by one state regulatory commission.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near-term. The future effects on our business, liquidity and financial results of a further deterioration of current conditions in the credit markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

The slowdown in the U.S. economy, together with increased mortgage defaults and significant decreases in the values of homes and investment assets, has adversely affected the financial resources of many domestic households. It is unclear whether the administrative and legislative responses to these conditions will be successful in ending the current recession, including the lowering of current high unemployment rates across the U.S. As a result, our customers may seek to use even less gas and it may become more difficult for them to pay their gas bills. This may slow collections and lead to higher than normal levels of accounts receivable. This in turn could increase our financing requirements and bad debt expense.

The costs of providing pension and postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results.

We provide a cash-balance pension plan and postretirement healthcare benefits to eligible full-time employees. Our costs of providing such benefits and related funding requirements are subject to changes in the market value of the assets funding our pension and postretirement healthcare plans. The fluctuations over the last two years in the values of investments that fund our pension and postretirement healthcare plans may significantly differ from or alter the values and actuarial assumptions we use to calculate our future pension plan expense and postretirement healthcare costs and funding requirements under the Pension Protection Act. Any significant declines in the value of these investments could increase the expenses of our pension and postretirement healthcare plans and related funding requirements in the future. Our costs of providing such benefits and related funding requirements are also subject to changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five to ten years, as well as various actuarial calculations and assumptions, which may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates and interest rates and other factors.

Our operations are exposed to market risks that are beyond our control which could adversely affect our financial results and capital requirements.

Our risk management operations are subject to market risks beyond our control, including market liquidity, commodity price volatility and counterparty creditworthiness. Although we maintain a risk management policy, we may not be able to completely offset the price risk associated with volatile gas prices or the risk in our natural gas marketing and pipeline, storage and other segments, which could lead to volatility in our earnings. Physical trading also introduces price risk on any net open positions at the end of each trading day, as well as volatility resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. Although we manage our business to maintain no open positions, there are times when limited net open positions related to our physical storage may occur on a short-term basis. The determination of our net open position as of the end of any particular trading day 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 such day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner because the timing of the recognition of profits or losses on the hedges for financial accounting purposes usually do not match up with the timing of the economic profits or losses on the item being hedged. This volatility may occur with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated. Further, if the local physical markets in which we trade do not move consistently with the NYMEX futures market, we could experience increased volatility in the financial results of our natural gas marketing and pipeline, storage and other segments.

Our natural gas marketing and pipeline, storage and other segments manage margins and limit risk exposure on the sale of natural gas inventory or the offsetting fixed-price purchase or sale commitments for physical quantities of natural gas through the use of a variety of financial instruments. However, contractual limitations could adversely affect our ability to withdraw gas from storage, which could cause us to purchase gas at spot prices in a rising market to obtain sufficient volumes to fulfill customer contracts. We could also realize financial losses on our efforts to limit risk as a result of volatility in the market prices of the underlying commodities or if a counterparty fails to perform under a contract. Further tightening of the credit markets could cause more of our counterparties to fail to perform than expected. In addition, adverse changes in the creditworthiness of our counterparties could limit the level of trading activities with these parties and increase the risk that these parties may not perform under a contract. These circumstances could also increase our capital requirements.

We are also subject to interest rate risk on our borrowings. In recent years, we have been operating in a relatively low interest-rate environment with both short and long-term interest rates being relatively low compared to historical interest rates. However, increases in interest rates could adversely affect our future financial results.

We are subject to state and local regulations that affect our operations and financial results.

Our natural gas distribution and regulated transmission and storage segments are subject to various regulated returns on our rate base in each jurisdiction in which we operate. We monitor the allowed rates of return and our effectiveness in earning such rates and initiate rate proceedings or operating changes as we believe are needed. In addition, in the normal course of business in the regulatory environment, assets may be placed in service and historical test periods established before rate cases can be filed that could result in an adjustment of our allowed returns. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we must suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as “regulatory lag.” Rate cases also involve a risk of rate reduction, because once rates have been approved, they are still subject to challenge for their reasonableness by appropriate regulatory authorities. In addition, regulators may review our purchases of natural gas and can adjust the amount of our gas costs that we pass through to our customers. Finally, our debt and equity financings are also subject to approval by regulatory commissions in several states, which could limit our ability to access or take advantage of changes in the capital markets.

Some of our operations are subject to increased federal regulatory oversight that could affect our operations and financial results.

FERC has regulatory authority that affects some of our operations, including sales of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. Under legislation passed by Congress in 2005, FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC’s other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. We are currently under investigation by FERC for possible violations of its posting and competitive bidding regulations for pre-arranged released firm capacity on interstate natural gas pipelines. Should FERC conclude that we have committed such violations of its regulations and levies substantial fines and/or penalties against us, our business, financial condition or financial results could be adversely affected. In addition, although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

We are subject to environmental regulations which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There are a number of new federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. For example, in June 2009, the U.S. House of Representatives approved *The American Clean Energy and Security Act of 2009*, also known as the Waxman-Markey bill or "cap and trade" bill. The legislation, which strives to promote energy efficiency in the United States and reduce the amount of greenhouse gases produced, has implications for the natural gas industry. The bill, if adopted, would accelerate significantly the reduction in energy use per customer through a number of measures, including a dramatic tightening of building and appliance codes and other practices designed to put an increased focus on building and appliance efficiency. According to the bill, overall nationwide energy savings would total 75 percent by the year 2030 as a result of adopting its provisions. If adopted, the Waxman-Markey bill would establish a phased-in greenhouse gas emission cap-and-trade program that would reduce overall greenhouse gas emissions from capped sources by 17 percent by 2020 compared to emissions from such sources in 2005. These caps would be postponed on natural gas residential and commercial customers until 2016. Subsequent to the adoption by the House of this bill, a similar bill was introduced in the U.S. Senate, entitled the *Clean Energy Jobs and American Power Act,* also known as the Kerry-Boxer bill. At this time, the Kerry-Boxer bill is awaiting Senate action. The adoption of this legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations on our future business, financial condition or financial results.

The concentration of our distribution, pipeline and storage operations in the State of Texas exposes our operations and financial results to economic conditions and regulatory decisions in Texas.

Over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general and regulatory decisions by state and local regulatory authorities in Texas.

Adverse weather conditions could affect our operations or financial results.

Since the 2006-2007 winter heating season, we have had weather-normalized rates for over 90 percent of our residential and commercial meters, which has substantially mitigated the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather — normalized rates could have an adverse effect on our operations and financial results. In addition, our natural gas distribution and regulated transmission and storage operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Sustained cold weather could adversely affect our natural gas marketing operations as we may be required to purchase gas at spot rates in a rising market to obtain sufficient volumes to fulfill some customer contracts.

Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.

Inflation has caused increases in some of our operating expenses and has required assets to be replaced at higher costs. We have a process in place to continually review the adequacy of our natural gas distribution gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. However, the ability to control expenses is an important factor that could impact future financial results.

Rapid increases in the costs of purchased gas would cause us to experience a significant increase in short-term debt. We must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our natural gas distribution collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense.

Our growth in the future may be limited by the nature of our business, which requires extensive capital spending.

We must continually build additional capacity in our natural gas distribution system to enable us to adequately serve any significant amount of additional customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. Our cash flows from operations generally are sufficient to supply funding for all our capital expenditures, including the financing of the costs of new construction along with capital expenditures necessary to maintain our existing natural gas system. Due to the timing of these cash flows and capital expenditures, we often must fund at least a portion of these costs through borrowing funds from third party lenders, the cost and availability of which is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Our operations are subject to increased competition.

In residential and commercial customer markets, our natural gas distribution operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This could adversely impact our business if, as a result, our customer growth slows, reducing our ability to make capital expenditures, or if our customers further conserve their use of gas, resulting in reduced gas purchases and customer billings.

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our regulated transmission and storage segment currently faces limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, competition may increase if new intrastate pipelines are constructed near our existing facilities.

Distributing and storing natural gas involve risks that may result in accidents and additional operating costs.

Our natural gas distribution business involves a number of hazards and operating risks that cannot be completely avoided, such as leaks, accidents and operational problems, which could cause loss of human life, as well as substantial financial losses resulting from property damage, damage to the environment and to our operations. We do have liability and property insurance coverage in place for many of these hazards and risks. However, because our pipeline, storage and distribution facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by insurance, our operations or financial results could be adversely affected.

Natural disasters, terrorist activities or other significant events could adversely affect our operations or financial results.

Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may be more limited, which could increase the risk that an event could adversely affect our operations or financial results.

ITEM 1B. *Unresolved Staff Comments.*

Not applicable.

ITEM 2. *Properties.*

Distribution, transmission and related assets

At September 30, 2009, our natural gas distribution segment owned an aggregate of 70,879 miles of underground distribution and transmission mains throughout our gas distribution systems. These mains are located on easements or rights-of-way which generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. Our regulated transmission and storage segment owned 5,950 miles of gas transmission and gathering lines and our pipeline, storage and other segment owned 113 miles of gas transmission and gathering lines.

Storage Assets

We own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf)[1]	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Natural Gas Distribution Segment				
Kentucky	4,442,696	6,322,283	10,764,979	109,100
Kansas	3,239,000	2,300,000	5,539,000	45,000
Mississippi	2,211,894	2,442,917	4,654,811	48,000
Georgia	490,000	10,000	500,000	30,000
Total	10,383,590	11,075,200	21,458,790	232,100
Regulated Transmission and Storage Segment — Texas	39,243,226	13,128,025	52,371,251	1,235,000
Pipeline, Storage and Other Segment				
Kentucky	3,492,900	3,295,000	6,787,900	71,000
Louisiana	438,583	300,973	739,556	56,000
Total	3,931,483	3,595,973	7,527,456	127,000
Total	53,558,299	27,799,198	81,357,497	1,594,100

(1) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MMBtu)[1]
Natural Gas Distribution Segment			
	Colorado-Kansas Division	3,237,243	97,832
	Kentucky/Mid-States Division	18,497,006	348,290
	Louisiana Division	2,574,479	158,731
	Mississippi Division	3,875,429	165,402
	West Texas Division	1,225,000	56,000
Total		29,409,157	826,255
Natural Gas Marketing Segment	Atmos Energy Marketing, LLC	9,539,053	278,417
Pipeline, Storage and Other Segment	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total Contracted Storage Capacity		40,622,210	1,172,179

(1) Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

Other facilities

Our natural gas distribution segment owns and operates one propane peak shaving plant with a total capacity of approximately 180,000 gallons that can produce an equivalent of approximately 3,300 Mcf daily.

Offices

Our administrative offices and corporate headquarters are consolidated in a leased facility in Dallas, Texas. We also maintain field offices throughout our distribution system, the majority of which are located in leased facilities. Our nonregulated operations are headquartered in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

ITEM 3. ***Legal Proceedings.***

See Note 12 to the consolidated financial statements.

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

No matters were submitted to a vote of security holders during the fourth quarter of fiscal 2009.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2009, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
Robert W. Best	62	12	Chairman and Chief Executive Officer
Kim R. Cocklin	58	3	President and Chief Operating Officer
Louis P. Gregory	54	9	Senior Vice President and General Counsel
Michael E. Haefner	49	1	Senior Vice President, Human Resources
Mark H. Johnson	50	8	Senior Vice President, Nonregulated Operations and President, Atmos Energy Marketing, LLC
Fred E. Meisenheimer	65	9	Senior Vice President and Chief Financial Officer

Robert W. Best was named Chairman of the Board, President and Chief Executive Officer in March 1997. Since October 1, 2008, Mr. Best has continued to serve the Company as Chairman of the Board and Chief Executive Officer.

Kim R. Cocklin joined the Company in June 2006 as Senior Vice President, Regulated Operations. On October 1, 2008, Mr. Cocklin was named President and Chief Operating Officer. On November 10, 2009, Mr. Cocklin was elected to the Board of Directors. Prior to joining the Company, Mr. Cocklin served as Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 to May 2006.

Louis P. Gregory was named Senior Vice President and General Counsel in September 2000.

Michael E. Haefner joined the Company in June 2008 as Senior Vice President, Human Resources. Prior to joining the Company, Mr. Haefner was a self-employed consultant and founder and president of Perform for Life, LLC from May 2007 to May 2008. Mr. Haefner previously served for 10 years as the Senior Vice President, Human Resources, of Sabre Holding Corporation, the parent company of Sabre Airline Solutions, Sabre Travel Network and Travelocity.

Mark H. Johnson was named Senior Vice President, Nonregulated Operations in April 2006 and President of Atmos Energy Holdings, Inc., and Atmos Energy Marketing, LLC, in April 2005. Mr. Johnson previously served the Company as Vice President, Nonutility Operations from October 2005 to March 2006 and as Executive Vice President of Atmos Energy Marketing from October 2003 to March 2005. Mr. Johnson left his position with the Company to pursue other interests, effective October 31, 2009.

Fred E. Meisenheimer was named Senior Vice President and Chief Financial Officer in February 2009. Mr. Meisenheimer previously served the Company as Vice President and Controller from July 2000 through May 2009 and also served as interim Chief Financial Officer beginning in January 2009.

PART II

ITEM 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The high and low sale prices and dividends paid per share of our common stock for fiscal 2009 and 2008 are listed below. The high and low prices listed are the closing NYSE quotes, as reported on the NYSE composite tape, for shares of our common stock:

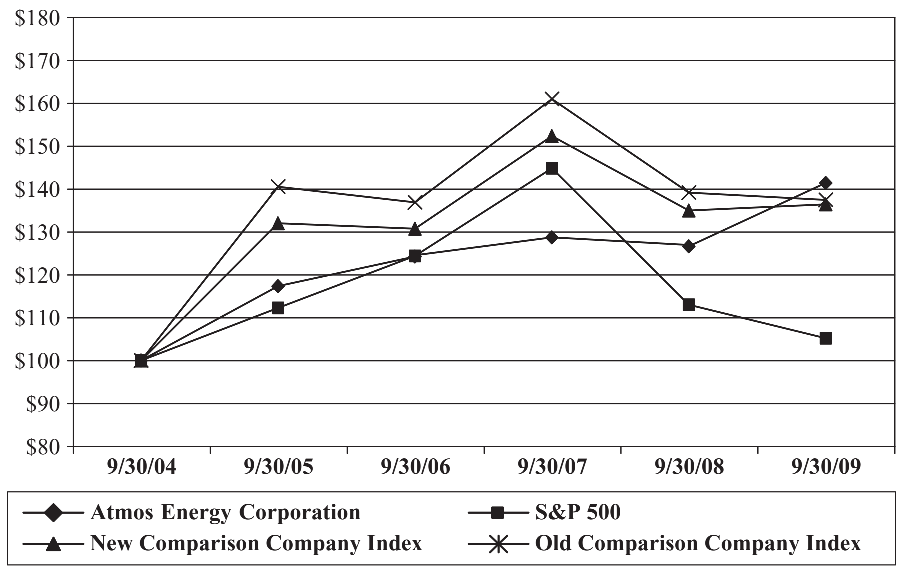
	2009			2008		
	High	Low	Dividends paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$27.88	$21.17	$.330	$29.46	$26.11	$.325
March 31	25.95	20.20	.330	28.96	25.09	.325
June 30	26.37	22.81	.330	28.54	25.81	.325
September 30	28.80	24.65	.330	28.25	25.49	.325
			$1.32			$1.30

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2009 was 20,824. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2009 that were not registered under the Securities Act of 1933, as amended.

Performance Graph

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the Standard and Poor's 500 Stock Index and the cumulative total return of two different customized peer company groups, the New Comparison Company Index and the Old Comparison Company Index. The New Comparison Company Index includes National Fuel Gas and excludes Questar Corporation because the Board of Directors determined that National Fuel Gas better fits the profile of the companies in the peer group, which is comprised of natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2004 in our common stock, the S&P 500 Index and in the common stock of the companies in the New and Old Comparison Company Indexes, as well as a reinvestment of dividends paid on such investments throughout the period.

Comparison of Five-Year Cumulative Total Return among Atmos Energy Corporation, S&P 500 Index and Comparison Company Indices



	Cumulative Total Return					
	9/30/04	9/30/05	9/30/06	9/30/07	9/30/08	9/30/09
Atmos Energy Corporation	100.00	117.33	124.23	128.40	126.62	141.40
S&P 500 Index	100.00	112.25	124.37	144.81	112.99	105.18
New Comparison Company Index	100.00	131.99	130.72	152.32	134.96	136.40
Old Comparison Company Index	100.00	140.50	136.86	160.95	139.13	137.43

The New Comparison Company Index contains a hybrid group of utility companies, primarily natural gas distribution companies, recommended by a global management consulting firm and approved by the Board of Directors. The companies included in the index are AGL Resources Inc., CenterPoint Energy Resources Corporation, CMS Energy Corporation, EQT Corporation (formerly known as Equitable Resources, Inc.), Integrys Energy Group, Inc., National Fuel Gas, Nicor Inc., NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Vectren Corporation and WGL Holdings, Inc. The Old Comparison Company Index includes the companies listed above in the New Comparison Company Index with the exception of National Fuel Gas, which replaced Questar Corporation in the Company's peer group in the current year for the reasons discussed above.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2009.

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	611,227	$21.88	1,473,531
Total equity compensation plans approved by security holders	611,227	21.88	1,473,531
Equity compensation plans not approved by security holders	—	—	—
Total	611,227	$21.88	1,473,531

ITEM 6. *Selected Financial Data.*

The following table sets forth selected financial data of the Company and should be read in conjunction with the consolidated financial statements included herein.

	Fiscal Year Ended September 30				
	2009(1)	2008	2007(1)	2006(1)	2005
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$4,969,080	$7,221,305	$5,898,431	$6,152,363	$4,961,873
Gross profit	1,346,702	1,321,326	1,250,082	1,216,570	1,117,637
Operating expenses(1)	899,300	893,431	851,446	833,954	768,982
Operating income	447,402	427,895	398,636	382,616	348,655
Miscellaneous income (expense)	(3,303)	2,731	9,184	881	2,021
Interest charges	152,830	137,922	145,236	146,607	132,658
Income before income taxes	291,269	292,704	262,584	236,890	218,018
Income tax expense	100,291	112,373	94,092	89,153	82,233
Net income	$ 190,978	$ 180,331	$ 168,492	$ 147,737	$ 135,785
Weighted average diluted shares outstanding	92,024	90,272	87,745	81,390	79,012
Diluted net income per share	$ 2.08	$ 2.00	$ 1.92	$ 1.82	$ 1.72
Cash flows from operations	$ 919,233	$ 370,933	$ 547,095	$ 311,449	$ 386,944
Cash dividends paid per share	$ 1.32	$ 1.30	$ 1.28	$ 1.26	$ 1.24
Total natural gas distribution throughput (MMcf)(2)	408,885	429,354	427,869	393,995	411,134
Total regulated transmission and storage transportation volumes (MMcf)(2)	528,689	595,542	505,493	410,505	373,879
Total natural gas marketing sales volumes (MMcf)(2)	370,569	389,392	370,668	283,962	238,097
Financial Condition					
Net property, plant and equipment	$4,439,103	$4,136,859	$3,836,836	$3,629,156	$3,374,367
Working capital	91,519	78,017	149,217	(1,616)	151,675
Total assets	6,343,766	6,386,699	5,895,197	5,719,547	5,610,547
Short-term debt, inclusive of current maturities of long-term debt	72,681	351,327	154,430	385,602	148,073
Capitalization:					
Shareholders' equity	2,176,761	2,052,492	1,965,754	1,648,098	1,602,422
Long-term debt (excluding current maturities)	2,169,400	2,119,792	2,126,315	2,180,362	2,183,104
Total capitalization	4,346,161	4,172,284	4,092,069	3,828,460	3,785,526
Capital expenditures	509,494	472,273	392,435	425,324	333,183
Financial Ratios					
Capitalization ratio(3)	49.3%	45.4%	46.3%	39.1%	40.7%
Return on average shareholders' equity(4)	8.9%	8.8%	8.8%	8.9%	9.0%

(1) Financial results for 2009, 2007 and 2006 include a $5.4 million, $6.3 million and a $22.9 million pre-tax loss for the impairment of certain assets.

(2) Net of intersegment eliminations

(3) The capitalization ratio is calculated by dividing shareholders' equity by the sum of total capitalization and short-term debt, inclusive of current maturities of long-term debt.

(4) The return on average shareholders' equity is calculated by dividing current year net income by the average of shareholders' equity for the previous five quarters.

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

INTRODUCTION

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation and its consolidated subsidiaries with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A above, "Risk Factors". They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

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

The statements contained in this Annual Report on Form 10-K 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 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 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, especially those discussed in Item 1A above, 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our 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, fair value measurements, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Our critical accounting policies are reviewed by the Audit Committee quarterly. Actual results may differ from estimates.

Regulation — Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. We meet the criteria established within accounting principles generally accepted in the United States of a cost-based, rate-regulated entity, which requires us to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in our financial statements in accordance with applicable authoritative accounting standards. We apply the provisions of this standard to our regulated operations and record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our regulated operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

Revenue recognition — Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulatory authorities, which are subject to refund. We recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas cost adjustment mechanisms. Purchased gas cost adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of cost, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility company's other costs, (ii) represents a large component of the utility company's cost of service and (iii) is generally outside the control of the gas utility company. There is no gross profit generated through purchased gas cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all natural gas distribution sales to our customers fluctuate with the cost of gas that we purchase, our gross profit is generally not affected by fluctuations in the cost of gas as a result of the purchased gas cost adjustment mechanism. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our regulated transmission and storage and pipeline, storage and other segments are recognized in the period in which actual volumes are transported and storage services are provided.

Operating revenues for our natural gas marketing segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments.

Allowance for doubtful accounts — Accounts receivable arise from natural gas sales to residential, commercial, industrial, municipal and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Financial instruments and hedging activities — We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically use financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to meet the needs of our regulated and nonregulated businesses.

We record all of our financial instruments on the balance sheet at fair value as required by accounting principles generally accepted in the United States, with changes in fair value ultimately recorded in the income statement. The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

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. The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk in this segment 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 accounting principles generally accepted in the United States. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. We also perform asset optimization activities in both our natural gas marketing segment and pipeline, storage and other segment. 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 the risk of natural gas price changes through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties.

In our natural gas marketing and pipeline, storage and other segments, we have designated the natural gas inventory held by these operating segments as the hedged item in a fair-value hedge. This 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 or losses in revenue in the period of change. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges and are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial instruments designated against our physical inventory (NYMEX) and the market (spot) prices used to value our physical storage (Gas Daily) result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. The difference in the spot price used to value our physical inventory and the forward price used to value the related financial instruments can result in volatility in our reported income as a component of unrealized margins. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized. Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

We have elected to treat fixed-price forward contracts used in our natural gas marketing segment to deliver gas as normal purchases and normal sales. As such, these deliveries are recorded on an accrual basis in accordance with our revenue recognition policy. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on open financial instruments are recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

We also use storage swaps and futures to capture additional storage arbitrage opportunities in our natural gas marketing segment that arise after 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.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt. As of September 30, 2009, we had no financial instruments in place to manage interest rate risk. However, in prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as a cash flow hedge of an anticipated transaction at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). The realized gain or loss recognized upon settlement of each Treasury lock agreement was initially recorded as a component of accumulated other comprehensive income (loss) and is recognized as a component of interest expense over the life of the related financing arrangement.

Impairment assessments — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. As of September 30, 2009, we had no indefinite-lived intangible assets.

We annually evaluate our goodwill balances for impairment during our second fiscal quarter or as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. We have determined our reporting units to be each of our natural gas distribution divisions and wholly-owned subsidiaries and goodwill is allocated to the reporting units responsible for the acquisition that gave rise to the goodwill. The discounted cash flow calculations used to assess goodwill impairment are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

We annually assess whether the cost of our intangible assets subject to amortization or other long-lived assets is recoverable or that the remaining useful lives may warrant revision. We perform this assessment more frequently when specific events or circumstances have occurred that suggest the recoverability of the cost of the intangible and other long-lived assets is at risk.

When such events or circumstances are present, we assess the recoverability of these assets by determining whether the carrying value will be recovered through expected future cash flows from the operating division or subsidiary to which these assets relate. These cash flow projections consider various factors such as the timing of the future cash flows and the discount rate and are based upon the best information available at the time the estimate is made. Changes in these factors could materially affect the cash flow projections and result in the recognition of an impairment charge. An impairment charge is recognized as the difference between the carrying amount and the fair value if the sum of the undiscounted cash flows is less than the carrying value of the related asset.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Prior to fiscal 2009, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. Effective October 1, 2008, we changed our measurement date to September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When establishing our discount rate, we consider high quality corporate bond rates, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan costs are not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately \$0.8 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately \$0.9 million.

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 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 current accounting standards. 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.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. 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.

RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 64 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

Additionally, the seasonality of our business impacts our working capital differently at various times during the year. Typically, our accounts receivable, accounts payable and short-term debt balances peak by the end of January and then start to decline, as customers begin to pay their winter heating bills. Gas stored underground, particularly in our natural gas distribution segment, typically peaks in November and declines as we utilize storage gas to serve our customers.

During the current 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 took 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. Then, in October 2009, we replaced the $212.5 million 364-day committed credit facility with a new 364-day $200 million committed credit facility. We also converted AEM's former $580 million uncommitted credit facility to a 364-day $375 million committed credit facility in December 2008. 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 $902.0 million 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 have improved our ability to access the short-term capital markets to satisfy our liquidity requirements on more economical terms.

However, the turmoil in the financial markets did also have a direct financial impact on our results of operations. We determined that the decline in fair value for certain available-for-sale securities in our Supplemental Executive Benefit Plans experienced during the year ended September 30, 2009 was other than temporary and, accordingly, recorded a $5.4 million noncash charge to impair the assets. As a result of these impairments, we do not maintain any investments that are in an unrealized loss position.

Finally, challenging economic times resulted in a general decline in throughput across 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 5 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 an 11 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. 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.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2009, 2008 and 2007.

	For the Fiscal Year Ended September 30		
	2009	2008	2007
	(In thousands, except per share data)		
Operating revenues	$4,969,080	$7,221,305	$5,898,431
Gross profit	1,346,702	1,321,326	1,250,082
Operating expenses	899,300	893,431	851,446
Operating income	447,402	427,895	398,636
Miscellaneous income (expense)	(3,303)	2,731	9,184
Interest charges	152,830	137,922	145,236
Income before income taxes	291,269	292,704	262,584
Income tax expense	100,291	112,373	94,092
Net income	$ 190,978	$ 180,331	$ 168,492
Earnings per diluted share	$ 2.08	$ 2.00	$ 1.92

Historically, our regulated operations arising from our natural gas distribution and regulated transmission and storage operations contributed 65 to 85 percent of our consolidated net income. Regulated operations contributed 83 percent, 74 percent and 64 percent to our consolidated net income for fiscal years 2009, 2008, and 2007. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended September 30		
	2009	2008	2007
	(In thousands)		
Natural gas distribution segment	$116,807	$ 92,648	$ 73,283
Regulated transmission and storage segment	41,056	41,425	34,590
Natural gas marketing segment	20,194	29,989	45,769
Pipeline, storage and other segment	12,921	16,269	14,850
Net income	$190,978	$180,331	$168,492

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

	For the Fiscal Year Ended September 30		
	2009	2008	2007
	(In thousands, except per share data)		
Regulated operations	$157,863	$134,073	$107,873
Nonregulated operations	33,115	46,258	60,619
Consolidated net income	$190,978	$180,331	$168,492
Diluted EPS from regulated operations	$ 1.72	$ 1.49	$ 1.23
Diluted EPS from nonregulated operations	0.36	0.51	0.69
Consolidated diluted EPS	$ 2.08	$ 2.00	$ 1.92

Net income during fiscal 2009 increased six percent over fiscal 2008. Net income from our regulated operations increased 18 percent during fiscal 2009. The increase primarily reflects a $32.3 million increase in gross profit resulting from the net favorable impact of various ratemaking activities in our natural gas distribution segment, partially offset by higher depreciation expense, pipeline maintenance costs and interest expense. Net income in our nonregulated operations decreased $13.1 million, primarily due to the impact of unrealized margins. Unrealized margins totaled $35.9 million which reduced earnings per share by $0.23 per diluted share. The overall increase in consolidated net income was also favorably affected by non-recurring items totaling $17.1 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
- $7.6 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 of $5.4 million related to available-for-sale securities in our Supplemental Executive Retirement Plan

Net income during fiscal 2008 increased seven percent over fiscal 2007. Net income from our regulated operations increased 24 percent during fiscal 2008. The increase primarily reflects a $53.8 million increase in gross profit resulting from our ratemaking efforts, coupled with higher per-unit transportation margins and an 18 percent increase in consolidated throughput in our Atmos Pipeline — Texas Division. These increases were partially offset by a four percent increase in operating expenses. Net income in our nonregulated operations experienced a 24 percent decline as less volatile natural gas market conditions significantly reduced our asset optimization margins. However, higher delivered gas margins in our natural gas marketing segment and unrealized margins partially offset this decrease.

See the following discussion regarding the results of operations for each of our business operating segments.

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 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. The "Ratemaking Activity" section of this Form 10-K describes our current rate strategy and recent ratemaking initiatives in more detail.

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 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 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. Although this timing difference will still be present for gross receipts taxes, the timing differences described above should 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 fiscal years ended September 30, 2009, 2008 and 2007 are presented below.

	For the Fiscal Year Ended September 30				
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
	(In thousands, unless otherwise noted)				
Gross profit	$1,024,628	$1,006,066	$952,684	$ 18,562	$53,382
Operating expenses	735,614	744,901	731,497	(9,287)	13,404
Operating income	289,014	261,165	221,187	27,849	39,978
Miscellaneous income	5,766	9,689	8,945	(3,923)	744
Interest charges	124,055	117,933	121,626	6,122	(3,693)
Income before income taxes	170,725	152,921	108,506	17,804	44,415
Income tax expense	53,918	60,273	35,223	(6,355)	25,050
Net income	$ 116,807	$ 92,648	$ 73,283	$ 24,159	$19,365
Consolidated natural gas distribution sales volumes — MMcf	282,117	292,676	297,327	(10,559)	(4,651)
Consolidated natural gas distribution transportation volumes — MMcf	126,768	136,678	130,542	(9,910)	6,136
Total consolidated natural gas distribution throughput — MMcf	408,885	429,354	427,869	(20,469)	1,485
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.44	$ 0.45	$ 0.03	$ (0.01)
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 6.95	$ 9.05	$ 8.09	$ (2.10)	$ 0.96

The following table shows our operating income by natural gas distribution division for the fiscal years ended September 30, 2009, 2008 and 2007. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
	(In thousands)				
Mid-Tex	$127,625	$115,009	$ 68,574	$12,616	$46,435
Kentucky/Mid-States	47,978	48,731	42,161	(753)	6,570
Louisiana	43,434	39,090	44,193	4,344	(5,103)
West Texas	23,338	13,843	21,036	9,495	(7,193)
Mississippi	21,287	19,970	23,225	1,317	(3,255)
Colorado-Kansas	21,321	20,615	22,392	706	(1,777)
Other	4,031	3,907	(394)	124	4,301
Total	$289,014	$261,165	$221,187	$27,849	$39,978

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

The $18.6 million increase in natural gas distribution gross profit primarily reflects an increase in rates. The major components of the increase are as follows:

- $13.6 million net increase in rates in the Mid-Tex Division 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 and Environs (the Settled Cities) and adjustments for customers in the City of Dallas.

- $16.0 million increase in other rate adjustments primarily in Georgia, Kansas, Louisiana and West Texas.

- $7.6 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.

- $7.0 million uncollectible gas cost accrual recorded in a prior year that was reversed in the current year period.

These increases were partially offset by:

- $17.9 million decrease as a result of a five percent decrease in consolidated 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.

- $10.8 million decrease due to lower revenue related taxes, partially offset by the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income discussed below.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $9.3 million, primarily due to the following:

- $10.6 million decrease due to lower legal, fuel and other administrative costs.

- $9.2 million decrease in allowance for doubtful accounts due to the impact of recent rate design changes in certain jurisdictions that allow us to recover the gas cost portion of uncollectible accounts as well as a 23 percent year-over-year decline in the average cost of gas.

- $9.2 million decrease in taxes other than income primarily associated with lower franchise fees and state gross receipt taxes.

These decreases were partially offset by:

- $15.1 million increase in depreciation and amortization, due primarily to additional assets placed in service during the current year.

- $4.6 million increase due to a noncash charge to impair certain available-for-sale investments as we believed the fair value of these investments would not recover within a reasonable period of time.

Results for the current year include a $10.5 million tax benefit associated with updating the rates used to determine our deferred taxes. In addition, results for the prior year included a $1.2 million gain on the sale of irrigation assets in our West Texas Division.

Interest charges increased $6.1 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, we experienced higher average short-term debt balances, interest rates and commitment fees during the current year compared to the prior year.

Fiscal year ended September 30, 2008 compared with fiscal year ended September 30, 2007

The $53.4 million increase in natural gas distribution gross profit is primarily the result of increased rates and higher revenue-related taxes. The major components of the increase are as follows:

- $29.2 million increase in rates in the Mid-Tex Division due to its 2006 GRIP filing, the fiscal 2008 and 2007 rate cases and the absence of a one time GRIP refund that occurred in fiscal 2007.
- $14.4 million increase in rates in the Kansas, Kentucky, Louisiana, Tennessee and West Texas divisions.
- $8.6 million increase due to higher revenue related taxes, partially offset by the associated franchise and state gross receipts tax expense recorded as a component of taxes other than income discussed below.
- $7.5 million increase due to an accrual for estimated unrecoverable gas costs in fiscal 2007 that did not recur in fiscal 2008.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased by a net $13.4 million, primarily due to the following:

- $9.0 million increase primarily due to higher employee and administrative costs and increased natural gas odorization and fuel costs.
- $7.2 increase in franchise and state gross receipts taxes due to higher revenues.
- $4.3 million increase due to the absence in the current year of the deferral of hurricane-related operation and maintenance expenses in fiscal 2007.
- $3.3 million noncash charge associated with the write-off of software costs in fiscal 2007 that did not recur in fiscal 2008.

These increases were offset by a $3.2 million decrease in the provision for doubtful accounts, which reflects our continued effective collection efforts.

The increase in miscellaneous income primarily reflects the recognition of a $1.2 million gain on the sale of irrigation assets in our West Texas Division during the fiscal 2008 second quarter.

Interest charges allocated to the natural gas distribution segment decreased $3.7 million due to lower average outstanding short-term debt balances in fiscal 2008 compared with fiscal 2007.

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 arrangements, lending 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. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Additionally, pricing differences that occur between the natural gas hubs served by our pipeline could significantly impact our results as we can profit through the arbitrage of these spreads. Spread differences are influenced by supply and demand constraints not only in the markets we directly serve but in other markets as well. 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 fiscal years ended September 30, 2009, 2008 and 2007 are presented below.

	For the Fiscal Year Ended September 30				
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$ 89,348	$ 86,665	$ 77,090	$ 2,683	$ 9,575
Third-party transportation	95,314	85,256	65,158	10,058	20,098
Storage and park and lend services	11,858	9,746	9,374	2,112	372
Other	13,138	14,250	11,607	(1,112)	2,643
Gross profit	209,658	195,917	163,229	13,741	32,688
Operating expenses	116,495	106,172	83,399	10,323	22,773
Operating income	93,163	89,745	79,830	3,418	9,915
Miscellaneous income	1,433	1,354	2,105	79	(751)
Interest charges	30,982	27,049	27,917	3,933	(868)
Income before income taxes	63,614	64,050	54,018	(436)	10,032
Income tax expense	22,558	22,625	19,428	(67)	3,197
Net income	$ 41,056	$ 41,425	$ 34,590	$ (369)	$ 6,835
Gross pipeline transportation volumes — MMcf	706,132	782,876	699,006	(76,744)	83,870
Consolidated pipeline transportation volumes — MMcf	528,689	595,542	505,493	(66,853)	90,049

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

The $13.7 million increase in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $13.0 million increase from higher demand-based fees.
- $5.6 million increase resulting from higher transportation fees on through-system deliveries due to market conditions.
- $5.4 million increase due to our GRIP filings.

These increases were partially offset by an $8.4 million decrease associated with a decrease in transportation volumes to our Mid-Tex Division due to warmer weather and a decrease in electrical generation, Barnett Shale and HUB deliveries.

Operating expenses increased $10.3 million primarily due to higher levels of pipeline maintenance activities.

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.

Fiscal year ended September 30, 2008 compared with fiscal year ended September 30, 2007

The $32.7 million increase in regulated transmission and storage gross profit is primarily the result of rate adjustments and increased volumes. The major components of the increase are as follows:

- $13.1 million increase from rate adjustments resulting from our 2006 and 2007 GRIP filings.
- $8.3 million increase from transportation volumes as consolidated throughput increased 18 percent primarily due to increased transportation in the Barnett Shale region of Texas.

- $8.0 million increase related to increased service fees and per-unit transportation margins due to favorable market conditions.
- $1.5 million increase due to new compression contracts and transportation capacity enhancements.
- $1.3 million increase in sales of excess gas compared to 2007.

Operating expenses increased $22.8 million primarily due to increased pipeline integrity and maintenance costs.

Natural Gas Marketing Segment

AEM's 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. 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 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 activities, 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 fiscal years ended September 30, 2009, 2008 and 2007 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 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 dependent upon the levels of our net physical position at the end of the reporting period.

	For the Fiscal Year Ended September 30				
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
	(In thousands, unless otherwise noted)				
Realized margins					
Delivered gas	$ 75,341	$ 73,627	$ 57,054	$ 1,714	$ 16,573
Asset optimization	37,670	(6,135)	28,827	43,805	(34,962)
	113,011	67,492	85,881	45,519	(18,389)
Unrealized margins	(28,399)	25,529	18,430	(53,928)	7,099
Gross profit	84,612	93,021	104,311	(8,409)	(11,290)
Operating expenses	38,208	36,629	29,271	1,579	7,358
Operating income	46,404	56,392	75,040	(9,988)	(18,648)
Miscellaneous income	537	2,022	6,434	(1,485)	(4,412)
Interest charges	12,911	9,036	5,767	3,875	3,269
Income before income taxes	34,030	49,378	75,707	(15,348)	(26,329)
Income tax expense	13,836	19,389	29,938	(5,553)	(10,549)
Net income	$ 20,194	$ 29,989	$ 45,769	$ (9,795)	$(15,780)
Gross natural gas marketing sales volumes — MMcf	441,081	457,952	423,895	(16,871)	34,057
Consolidated natural gas marketing sales volumes — MMcf	370,569	389,392	370,668	(18,823)	18,724
Net physical position (Bcf)	13.8	8.0	12.3	5.8	(4.3)

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

AEM's delivered gas business contributed 67 percent to total realized margins during fiscal 2009 with asset optimization activities contributing the remaining 33 percent. In the prior year, delivered gas activities represented substantially all of AEM's realized gross profit margin. The $45.5 million increase in realized gross profit reflected:

- A $43.8 million increase in asset optimization margins. AEM realized substantially all of its realized asset optimization margin in the fiscal 2009 first quarter when it realized substantially all of the economic value that it had captured as of September 30, 2008 from withdrawing gas and settling the associated financial instruments. 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 economic value it could realize in future periods from its asset optimization activities. In the prior year, AEM deferred storage withdrawals primarily into fiscal 2009 and recognized losses on the settlement of the associated financial instruments.

- A $1.7 million increase in realized delivered gas margins. AEM experienced a six percent increase in 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. These margin improvements more than offset a four percent decrease in gross sales volumes primarily attributable to lower industrial demand as a result of the current economic climate.

The increase in realized gross profit was more than offset by a $53.9 million decrease in unrealized margins attributable to the following:

- The realization of unrealized gains recorded during fiscal 2008.

- A modest widening of the physical/financial spreads, partially offset by favorable unrealized basis gains in certain markets.

- A 5.8 Bcf increase in AEM's net physical position.

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 $1.6 million primarily due the following factors:

- $4.0 million increase in legal and other administrative costs.

- $2.4 million decrease related to tax matters incurred in the prior year that did not recur in the current year.

Asset Optimization Activities

AEM 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 AEM'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.

The following table presents AEM's economic value and its potential gross profit (loss) at September 30, 2009 and 2008.

	September 30	
	2009	2008
	(In millions, unless otherwise noted)	
Economic value	$ 28.6	$ 48.5
Associated unrealized (gains) losses	11.0	(36.4)
Subtotal	39.6	12.1
Related fees[1]	(14.7)	(19.6)
Potential gross profit (loss)	$ 24.9	$ (7.5)
Net physical position (Bcf)	13.8	8.0

(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 September 30, 2009 and 2008.

During the year ended September 30, 2009, AEM's economic value decreased from $48.5 million, or $6.08/Mcf at September 30, 2008, to $28.6 million, or $2.07/Mcf. As discussed above, in the fiscal 2009 first quarter, AEM withdrew gas and realized substantially all of the economic value that it captured as of September 30, 2008. During the remainder of the year, as a result of falling current cash prices, AEM deferred certain storage withdrawals and has been a net injector of gas into storage to increase economic value that it can realize in future periods.

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 September 30, 2009 will be fully realized in the future nor can we ensure 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 September 30, 2009, without encountering operational or other issues, we anticipate the majority of the potential gross profit as of September 30, 2009 will be recognized during the first and second quarters of fiscal 2010.

Fiscal year ended September 30, 2008 compared with fiscal year ended September 30, 2007

AEM's delivered gas business represented substantially all of AEM's realized gross profit margin in fiscal 2008. In fiscal 2007, AEM's delivered gas business contributed 66 percent to total realized margins during the year with asset optimization activities contributing the remaining 34 percent. The $18.4 million decrease in realized gross profit reflected:

- A $35.0 million decrease in realized asset optimization margins. As a result of less volatile natural gas market conditions experienced during fiscal 2008, AEM regularly deferred storage withdrawals and reset the associated financial instruments to increase the future economic value it could realize in future periods from its asset optimization activities. AEM recognized losses on the settlement of the associated financial instruments without corresponding storage withdrawal gains. In fiscal 2007, AEM changed its withdrawal schedule within the fiscal year and recognized substantially smaller losses from resetting its position. Increased storage fees during fiscal 2008 also contributed to the decrease.
- A $16.6 million increase in realized delivered gas margins. Gross sales volumes increased eight percent due to the successful execution of our marketing strategies. Basis gains and contract renewals increased

per-unit margins 19 percent. Excluding the impact of basis gains, per-unit margins increased seven percent in fiscal 2008.

The decrease in realized gross profit was partially offset by a $7.1 million increase in unrealized margins attributable to:

- A narrowing of the spreads between current cash prices and forward natural gas prices. This impact was partially mitigated by a 4.3 Bcf decrease in the net physical position.
- The realization of unrealized gains recorded during fiscal 2007.

Operating expenses increased $7.4 million primarily due to the following:

- $5.0 million increase in other administrative costs.
- $2.4 million increase associated with property taxes.

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 and for our natural gas marketing segment, and, on a more limited basis, to 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 fiscal years ended September 30, 2009, 2008 and 2007 are presented below.

	For the Fiscal Year Ended September 30				
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
	(In thousands)				
Storage and transportation services	$12,784	$14,247	$14,213	$ (1,463)	$ 34
Asset optimization	21,474	5,178	12,101	16,296	(6,923)
Other	2,728	4,183	4,197	(1,455)	(14)
Unrealized margins	(7,490)	4,705	2,097	(12,195)	2,608
Gross profit	29,496	28,313	32,608	1,183	(4,295)
Operating expenses	11,019	8,064	10,373	2,955	(2,309)
Operating income	18,477	20,249	22,235	(1,772)	(1,986)
Miscellaneous income	6,253	8,428	8,173	(2,175)	255
Interest charges	1,830	2,322	6,055	(492)	(3,733)
Income before income taxes	22,900	26,355	24,353	(3,455)	2,002
Income tax expense	9,979	10,086	9,503	(107)	583
Net income	$12,921	$16,269	$14,850	$ (3,348)	$ 1,419

Fiscal year ended September 30, 2009 compared with fiscal year ended September 30, 2008

Gross profit from our pipeline, storage and other segment increased $1.2 million primarily due to the following:

- $16.3 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.
- $12.2 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 increased $3.0 million primarily due to increased employee costs and higher depreciation expense which was largely attributable to additional assets placed in service during the year.

Fiscal year ended September 30, 2008 compared with fiscal year ended September 30, 2007

Gross profit from our pipeline, storage and other segment decreased $4.3 million primarily due to the following factors:

- $6.9 million decrease in asset optimization margins as a result of a less volatile natural gas market.
- $2.6 million increase in unrealized margins associated with asset optimization activities.

Operating expenses decreased $2.3 million primarily due to the absence in fiscal 2008 of a $3.0 million noncash charge recorded in fiscal 2007 related to the write-off of costs associated with a natural gas gathering project.

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 without using our credit facilities. 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. Adverse developments in global financial and credit markets during the first fiscal quarter of 2009 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. Further, as a result of our financing activities described below, we received credit rating upgrades from two of the three credit rating agencies, which has reduced the cost of our commercial paper borrowings. At September 30, 2009, we had commercial paper outstanding of $72.6 million under this facility and $494.1 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.

In October 2009, we replaced our former $212.5 million 364-day committed credit facility that was entered into in October 2008 with a new 364-day credit facility on similar terms that will allow borrowings up to $200.0 million and expires in October 2010.

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. We are currently negotiating to renew this facility. 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 September 30, 2009, the amount available to us under our credit facilities, net of outstanding letters of credit, was approximately $902 million.

We believe the liquidity provided by our committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs, capital expenditures and other expenditures for fiscal year 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, the price for our services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the years ended September 30, 2009, 2008 and 2007 are presented below.

	For the Fiscal Year Ended September 30				
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
			(In thousands)		
Total cash provided by (used in)					
Operating activities	$ 919,233	$ 370,933	$ 547,095	$ 548,300	$(176,162)
Investing activities	(517,201)	(483,009)	(402,871)	(34,192)	(80,138)
Financing activities	(337,546)	98,068	(159,314)	(435,614)	257,382
Change in cash and cash equivalents	$ 64,486	$ (14,008)	$ (15,090)	$ 78,494	$ 1,082

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income, 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 purchased gas cost recoveries. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

Fiscal Year ended September 30, 2009 compared with fiscal year ended September 30, 2008

Operating cash flows were $548.3 million higher in fiscal 2009 compared to fiscal 2008, primarily due to the following:

- $368.9 million increase attributable 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.
- $56.8 million increase due to lower cash margin requirements related to our natural gas marketing financial instruments.
- These increases were partially offset by a $21.0 million decrease due to a contribution made to our pension plans in the current year.

Fiscal Year ended September 30, 2008 compared with fiscal year ended September 30, 2007

Operating cash flows were $176.2 million lower in fiscal 2008 compared to fiscal 2007, primarily due to the following:

- $95.7 million decrease due to higher cash margin requirements related to our natural gas marketing financial instruments.
- $92.6 million decrease due to the unfavorable timing of gas cost collections in our natural gas distribution segment.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund acquisitions and 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 focusing our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. 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.

For the fiscal year ended September 30, 2009, we incurred $509.5 million for capital expenditures compared with $472.3 million for the fiscal year ended September 30, 2008 and $392.4 million for the fiscal year ended September 30, 2007.

The increase in capital expenditures in fiscal 2009 compared to fiscal 2008 primarily reflects $32.6 million related to spending for a regulated transmission pipeline project completed in the fourth quarter of 2009.

The increase in capital expenditures in fiscal 2008 compared to fiscal 2007 primarily reflects the following:

- $50.3 million increase in compliance spending and main replacements in our Mid-Tex Division.
- $12.8 million increase in the natural gas distribution segment for our new automated meter reading initiative.
- $4.7 million increase related to spending for two nonregulated growth projects.

Cash flows from financing activities

For the fiscal year ended September 30, 2009, our financing activities used $337.5 million in cash, while financing activities for the fiscal year ended September 30, 2008 provided $98.1 million in cash compared with cash of $159.3 million used for the fiscal year ended September 30, 2007. Our significant financing activities for the fiscal years ended September 30, 2009, 2008 and 2007 are summarized as follows:

2009

During the fiscal year ended September 30, 2009, we:

- Paid $407.4 million to repay our $400 million 4.00% unsecured notes.
- Repaid a net $284.0 million of short-term borrowings under our credit facilities.
- Paid $121.5 million in cash dividends, which reflected a payout ratio of 63 percent of net income.
- Received $445.6 million in net proceeds related to the March 2009 issuance of $450 million of 8.50% Senior Notes due 2019. The net proceeds were used to repay the $400 million 4.00% unsecured notes.
- Received $27.7 million net proceeds related to the issuance of 1.2 million shares of common stock.
- Received $1.9 million net proceeds related to the settlement of the Treasury lock agreement associated with the March 2009 issuance of the $450 million of 8.50% Senior Notes due 2019.

2008

During the fiscal year ended September 30, 2008, we:

- Borrowed a net $200.2 million under our short-term facilities due to the impact of seasonal natural gas purchases and the effect of higher natural gas prices.
- Repaid $10.3 million of long-term debt in accordance with their normal maturity schedules.
- Received $25.5 million in net proceeds related to the issuance of 1.0 million shares of common stock.
- Paid $117.3 million in dividends, which reflected a payout ratio of 65 percent of net income.

2007

During the fiscal year ended September 30, 2007, we:

- Repaid a net $213.2 million of short-term borrowings under our credit facilities.
- Paid $303.2 million to repay our $300 million unsecured floating rate senior notes as discussed below.
- Received $247.2 million in net proceeds related to the June 2007 issuance of $250 million of 6.35% Senior Notes due 2017. We used the net proceeds of $247 million, together with $53 million of available cash, to repay our $300 million unsecured floating rate senior notes, which were redeemed on July 15, 2007.
- Paid $111.7 million in dividends, which reflected a payout ratio of 67 percent of net income.
- Received $24.9 million related to the issuance of common stock under various plans.
- Received $4.8 million related to the settlement of of the Treasury lock agreement associated with the June 2007 issuance of $250 million of 6.35% Senior Notes due 2017.

The following table shows the number of shares issued for the fiscal years ended September 30, 2009, 2008 and 2007:

	For the Fiscal Year Ended September 30		
	2009	2008	2007
Shares issued:			
Direct stock purchase plan	407,262	388,485	325,338
Retirement savings plan	640,639	558,014	422,646
1998 Long-term incentive plan	686,046	538,450	511,584
Outside directors stock-for-fee plan	3,079	3,197	2,453
December 2006 equity offering	—	—	6,325,000
Total shares issued	1,737,026	1,488,146	7,587,021

Credit Facilities

As of September 30, 2009, we had three committed credit facilities in our regulated operations totaling $804.2 million. These facilities included (1) a five-year $566.7 million unsecured facility expiring December 2011, (2) a $212.5 million unsecured facility expiring October 2009, and (3) a $25 million unsecured facility expiring March 31, 2010. At the time the $566.7 million credit facility was established, borrowings under the facility were limited to $600 million. However, in March 2009, the facility was amended to reduce the amount available to $566.7 million to reflect the bankruptcy of one lender that participated in the facility. In October 2009, we replaced our $212.5 million facility at its termination with a new $200 million unsecured 364-day facility. After giving effect to these changes, the amount available to us under our committed credit facilities was $791.7 million. As of September 30, 2009, we had no outstanding letters of credit under these facilities.

AEM has a committed credit facility that can provide up to $450 million to support its nonregulated activities, primarily the issuance of letters of credit to natural gas suppliers. As of September 30, 2009, the amount available to us under this credit facility, net of outstanding letters of credit, was $170.4 million. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months.

Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. However, we believe these credit facilities, combined with our operating cash flows will be sufficient to fund our working capital needs, our fiscal 2010 capital expenditure program and our common stock dividends. These facilities are described in further detail in Note 6 to the 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 September 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 $200 million of equity securities and $250 million of 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 Services, Inc. (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 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. 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. As of September 30, 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 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 September 30, 2009. Our debt covenants are described in Note 6 to the consolidated financial statements.

Capitalization

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

	September 30			
	2009		2008	
	(In thousands, except percentages)			
Short-term debt	$ 72,550	1.6%	$ 350,542	7.7%
Long-term debt	2,169,531	49.1%	2,120,577	46.9%
Shareholders' equity	2,176,761	49.3%	2,052,492	45.4%
Total capitalization, including short-term debt	$4,418,842	100.0%	$4,523,611	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 50.7 percent and 54.6 percent at September 30, 2009 and 2008. The decrease in the debt to capitalization ratio primarily reflects a decrease in short-term debt as of September 30, 2009 compared to the prior year. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We consider our optimal capitalization ratio to be in the range of 50 to 55 percent and seek to maintain this range 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

The following table provides information about contractual obligations and commercial commitments at September 30, 2009.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(In thousands)		
Contractual Obligations					
Long-term debt[1]	$2,172,827	$ 131	$362,565	$250,131	$1,560,000
Short-term debt[1]	72,550	72,550	—	—	—
Interest charges[2]	1,181,236	141,085	245,278	206,841	588,032
Gas purchase commitments[3]	338,746	312,837	15,232	10,677	—
Capital lease obligations[4]	1,565	186	372	372	635
Operating leases[4]	219,010	17,764	31,409	27,731	142,106
Demand fees for contracted storage[5]	28,459	12,475	13,534	2,200	250
Demand fees for contracted transportation[6]	41,948	9,810	16,783	12,198	3,157
Financial instrument obligations[7]	21,482	21,482	—	—	—
Postretirement benefit plan contributions[8]	162,782	12,242	22,857	28,686	98,997
Uncertain tax positions (including interest)[9]	6,731	—	6,731	—	—
Total contractual obligations	$4,247,336	$600,562	$714,761	$538,836	$2,393,177

(1) See Note 6 to the consolidated financial statements.

(2) Interest charges were calculated using the stated rate for each debt issuance.

(3) Gas purchase commitments were determined based upon contractually determined volumes at prices estimated based upon the index specified in the contract, adjusted for estimated basis differentials and contractual discounts as of September 30, 2009.

(4) See Note 13 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our natural gas marketing and pipeline, storage and other segments. Contractual demand fees for contracted storage for our natural gas distribution segment are excluded as these costs are fully recoverable through our purchase gas adjustment mechanisms.

(6) Represents third party contractual demand fees for transportation in our natural gas marketing segment.

(7) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2009. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled.

(8) Represents expected contributions to our postretirement benefit plans.

(9) Represents liabilities associated with uncertain tax positions claimed or expected to be claimed on tax returns.

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2009, AEM was committed to purchase 72.6 Bcf within one year, 19.4 Bcf within one to three years and 2.2 Bcf after three years under indexed contracts. AEM was committed to purchase 2.9 Bcf within one year under fixed price contracts with prices ranging from $2.95 to $7.68 per Mcf.

With the exception of our Mid-Tex Division, our natural gas distribution segment maintains supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under these contract terms as of September 30, 2009 are reflected in the table above.

Risk Management Activities

We use financial instruments to mitigate commodity price risk and, periodically, to manage interest rate risk. 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.

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, and 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.

We record our financial instruments as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. Substantially all of our financial instruments are valued using external market quotes and indices.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the fiscal year ended September 30, 2009 (in thousands):

Fair value of contracts at September 30, 2008	$ (63,677)
Contracts realized/settled	(102,943)
Fair value of new contracts	353
Other changes in value	152,101
Fair value of contracts at September 30, 2009	$ (14,166)

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

	Fair Value of Contracts at September 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	$(15,786)	$1,620	$—	$—	$(14,166)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(15,786)	$1,620	$—	$—	$(14,166)

The following table shows the components of the change in fair value of our natural gas marketing segment's financial instruments for the fiscal year ended September 30, 2009 (in thousands):

Fair value of contracts at September 30, 2008	$ 16,542
Contracts realized/settled	22,327
Fair value of new contracts	—
Other changes in value	(12,171)
Fair value of contracts at September 30, 2009	26,698
Netting of cash collateral	11,664
Cash collateral and fair value of contracts at September 30, 2009	$ 38,362

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

	Fair Value of Contracts at September 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	$14,283	$12,415	$—	$—	$26,698
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$14,283	$12,415	$—	$—	$26,698

Pension and Postretirement Benefits Obligations

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2009, our total net periodic pension and other benefits costs was $50.2 million, compared with $47.9 million and $48.6 million for the fiscal years ended September 30, 2008 and 2007. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates. A portion of these costs is capitalized into our gas distribution rate base, and the remaining costs are recorded as a component of operation and maintenance expense.

The increase in total net periodic pension and other benefits costs during fiscal 2009 compared with fiscal 2008 primarily reflects the change in assumptions we made during our annual pension plan valuation completed September 30, 2008. 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. At our September 30, 2008 measurement date, the interest rates were approximately 130 basis points higher than the interest rates at June 30, 2007, the measurement date used to determine our fiscal 2008 net periodic cost. The corresponding increase in the discount rate was the primary driver for the increase in our fiscal 2009 pension and benefit costs. Our expected return on our pension plan assets remained constant at 8.25 percent.

The periodic pension and other benefits costs remained relatively unchanged during fiscal 2008 compared with fiscal 2007 as the assumptions we made during our annual pension plan valuation completed June 30, 2007 were consistent with the prior year. At our June 30, 2007 measurement date, the interest rates were consistent with rates at our prior-year measurement date, which resulted in no change to our 6.30 percent discount rate used to determine our fiscal 2008 net periodic and post-retirement cost. In addition, our expected return on our pension plan assets remained constant at 8.25 percent.

Pension and Postretirement Plan Funding

Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Employee Retirement Income Security Act of 1974, including the funding requirements under the Pension Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2009, we contributed $21.0 million in cash to our pension plans to achieve a desired level of funding for the 2008 plan year while maximizing the tax deductibility of this payment. 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 funding threshold as established by the PPA. During fiscal 2008, we voluntarily contributed $2.3 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. This contribution achieved a desired level of funding for this plan for the 2007 plan year. During fiscal 2007, we did not contribute to our pension plans.

We contributed $10.1 million, $9.6 million and $11.8 million to our postretirement benefits plans for the fiscal years ended September 30, 2009, 2008 and 2007. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

Outlook for Fiscal 2010

As of September 30, 2009, interest and corporate bond rates utilized to determine our discount rates, which impacted our fiscal 2010 net periodic pension and postretirement costs, were lower than the interest and corporate bond rates as of September 30, 2008, the measurement date for our fiscal 2009 net periodic cost. As a result of the lower interest and corporate bond rates, we decreased the 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 which results in asset gains and losses that are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Accordingly, we expect our fiscal 2010 pension and postretirement medical costs to be materially the same as in fiscal 2009. Based upon market conditions subsequent to September 30, 2009, the current funded position of the plans and the new funding requirements under the PPA, we believe it is reasonably possible that we will be required to contribute to the Plans in fiscal 2010. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. However, we cannot anticipate with certainty whether such contributions will be made and the amount of such contributions. With respect to our postretirement medical plans, we anticipate contributing approximately $12.2 million during fiscal 2010.

As of September 30, 2009, the Board of Directors approved a change to the cost sharing methodology for employees who had not met the participation requirements by that date for the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the "Retiree Medical Plan"). Starting in five years, on January 1, 2015, the contribution rates that will apply to all non-grandfathered participants will be determined using a new cost sharing methodology by which Atmos Energy will limit its contribution to a three percent cost increase in claims and administrative costs each year. If medical costs covered by the Retiree Medical Plan increase more than three percent annually, participants will be responsible for the additional cost.

During the last fiscal year, the Company has worked with our independent compensation consultant to develop and implement a new SERP design for any new executives or current employees selected for participation in the SERP arrangement on a prospective basis. Only those executives who are currently members of our Management Committee as well as those individuals who may be selected in the future to serve on the Management Committee, plus those executives who are active SERP participants as of August 5, 2009, will continue to participate in the current SERP arrangement until their respective retirement dates. The current SERP arrangement is a 60 percent of covered compensation defined benefit arrangement in which benefits from the underlying qualified defined benefit plan are an offset to the SERP benefit. The new SERP arrangement for new participants in the Company's executive retirement program is a modified defined benefit approach in which the Company will contribute to a nominal account for each participant, an amount equal to ten percent of each participant's base salary and bonus following the participant's completion of a plan year of service. Other provisions of the plan mirror that of the Company's underlying qualified plan, the Pension Account Plan. At this time, only one employee has been selected for participation in the new SERP arrangement.

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.

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 consolidated financial statements.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business activities.

We conduct risk management activities through both our natural gas distribution and natural gas marketing segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to protect us and our customers against unusually large winter period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 4 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper and our other short-term borrowings.

Commodity Price Risk

Natural gas distribution segment

We purchase natural gas for our natural gas distribution operations. Substantially all of the costs of gas purchased for natural gas distribution operations are recovered from our customers through purchased gas cost adjustment mechanisms. Therefore, our natural gas distribution operations have limited commodity price risk exposure.

Natural gas marketing and pipeline, storage and other segments

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a $0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at September 30, 2009 of 0.4 Bcf, a $0.50 change in the forward NYMEX price would have had a $0.2 million impact on our consolidated net income.

Changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at September 30, 2009 and assuming our hedges would still qualify as highly effective, a $0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately $5.2 million.

Additionally, these changes could cause us to recognize a risk management liability, which would require us to place cash into an escrow account to collateralize this liability position. This, in turn, would reduce the amount of cash we would have on hand to fund our working capital needs.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately $3.7 million during 2009.

As of September 30, 2009, we were not engaged in other activities that would cause exposure to the risk of material earnings or cash flow loss due to changes in interest rates or market commodity prices.

ITEM 8. ***Financial Statements and Supplementary Data.***

Index to financial statements and financial statement schedule:

All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and accompanying notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON CONSOLIDATED FINANCIAL STATEMENTS

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2009 and 2008, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2009. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Atmos Energy Corporation's internal control over financial reporting as of September 30, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 16, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 16, 2009

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2009	September 30 2008
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,981,420	$5,650,096
Construction in progress	105,198	80,060
	6,086,618	5,730,156
Less accumulated depreciation and amortization	1,647,515	1,593,297
Net property, plant and equipment	4,439,103	4,136,859
Current assets		
Cash and cash equivalents	111,203	46,717
Accounts receivable, less allowance for doubtful accounts of $11,478 in 2009 and $15,301 in 2008	232,806	477,151
Gas stored underground	352,728	576,617
Other current assets	132,203	184,619
Total current assets	828,940	1,285,104
Goodwill and intangible assets	740,064	739,086
Deferred charges and other assets	335,659	225,650
	$6,343,766	$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: 2009 — 92,551,709 shares, 2008 — 90,814,683 shares	$ 463	$ 454
Additional paid-in capital	1,791,129	1,744,384
Accumulated other comprehensive loss	(20,184)	(35,947)
Retained earnings	405,353	343,601
Shareholders' equity	2,176,761	2,052,492
Long-term debt	2,169,400	2,119,792
Total capitalization	4,346,161	4,172,284
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	207,421	395,388
Other current liabilities	457,319	460,372
Short-term debt	72,550	350,542
Current maturities of long-term debt	131	785
Total current liabilities	737,421	1,207,087
Deferred income taxes	570,940	441,302
Regulatory cost of removal obligation	321,086	298,645
Deferred credits and other liabilities	368,158	267,381
	$6,343,766	$6,386,699

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2009	2008	2007
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,984,765	$3,655,130	$3,358,765
Regulated transmission and storage segment	209,658	195,917	163,229
Natural gas marketing segment	2,336,847	4,287,862	3,151,330
Pipeline, storage and other segment	41,924	31,709	33,400
Intersegment eliminations	(604,114)	(949,313)	(808,293)
	4,969,080	7,221,305	5,898,431
Purchased gas cost			
Natural gas distribution segment	1,960,137	2,649,064	2,406,081
Regulated transmission and storage segment	—	—	—
Natural gas marketing segment	2,252,235	4,194,841	3,047,019
Pipeline, storage and other segment	12,428	3,396	792
Intersegment eliminations	(602,422)	(947,322)	(805,543)
	3,622,378	5,899,979	4,648,349
Gross profit	1,346,702	1,321,326	1,250,082
Operating expenses			
Operation and maintenance	494,010	500,234	463,373
Depreciation and amortization	217,208	200,442	198,863
Taxes, other than income	182,700	192,755	182,866
Asset impairments	5,382	—	6,344
Total operating expenses	899,300	893,431	851,446
Operating income	447,402	427,895	398,636
Miscellaneous income (expense), net	(3,303)	2,731	9,184
Interest charges	152,830	137,922	145,236
Income before income taxes	291,269	292,704	262,584
Income tax expense	100,291	112,373	94,092
Net income	$ 190,978	$ 180,331	$ 168,492
Per share data			
Basic net income per share	$ 2.10	$ 2.02	$ 1.94
Diluted net income per share	$ 2.08	$ 2.00	$ 1.92
Weighted average shares outstanding:			
Basic	91,117	89,385	86,975
Diluted	92,024	90,272	87,745

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Additional	Accumulated Other		
	Number of Shares	Stated Value	Paid-in Capital	Comprehensive Loss	Retained Earnings	Total
	(In thousands, except share and per share data)					
Balance, September 30, 2006	81,739,516	$409	$1,467,240	$(43,850)	$ 224,299	$1,648,098
Comprehensive income:						
Net income	—	—	—	—	168,492	168,492
Unrealized holding gains on investments, net	—	—	—	1,241	—	1,241
Treasury lock agreements, net	—	—	—	6,288	—	6,288
Cash flow hedges, net	—	—	—	20,123	—	20,123
Total comprehensive income						196,144
Cash dividends ($1.28 per share)	—	—	—	—	(111,664)	(111,664)
Common stock issued:						
Public offering	6,325,000	32	191,881	—	—	191,913
Direct stock purchase plan	325,338	2	9,866	—	—	9,868
Retirement savings plan	422,646	2	12,929	—	—	12,931
1998 Long-term incentive plan	511,584	2	7,547	—	—	7,549
Employee stock-based compensation	—	—	10,841	—	—	10,841
Outside directors stock-for-fee plan	2,453	—	74	—	—	74
Balance, September 30, 2007	89,326,537	447	1,700,378	(16,198)	281,127	1,965,754
Comprehensive income:						
Net income	—	—	—	—	180,331	180,331
Unrealized holding losses on investments, net	—	—	—	(1,897)	—	(1,897)
Treasury lock agreements, net	—	—	—	3,148	—	3,148
Cash flow hedges, net	—	—	—	(21,000)	—	(21,000)
Total comprehensive income						160,582
Retroactive charge to record initial uncertain tax positions	—	—	—	—	(569)	(569)
Cash dividends ($1.30 per share)	—	—	—	—	(117,288)	(117,288)
Common stock issued:						
Direct stock purchase plan	388,485	2	10,333	—	—	10,335
Retirement savings plan	558,014	3	15,116	—	—	15,119
1998 Long-term incentive plan	538,450	2	5,592	—	—	5,594
Employee stock-based compensation	—	—	12,878	—	—	12,878
Outside directors stock-for-fee plan	3,197	—	87	—	—	87
Balance, September 30, 2008	90,814,683	454	1,744,384	(35,947)	343,601	2,052,492
Comprehensive income:						
Net income	—	—	—	—	190,978	190,978
Unrealized holding losses on investments, net	—	—	—	(1,820)	—	(1,820)
Other than temporary impairment of investments, net	—	—	—	3,370	—	3,370
Treasury lock agreements, net	—	—	—	3,606	—	3,606
Cash flow hedges, net	—	—	—	10,607	—	10,607
Total comprehensive income						206,741
Change in measurement date for employee benefit plans	—	—	—	—	(7,766)	(7,766)
Cash dividends ($1.32 per share)	—	—	—	—	(121,460)	(121,460)
Common stock issued:						
Direct stock purchase plan	407,262	2	8,743	—	—	8,745
Retirement savings plan	640,639	3	16,571	—	—	16,574
1998 Long-term incentive plan	686,046	4	8,075	—	—	8,079
Employee stock-based compensation	—	—	13,280	—	—	13,280
Outside directors stock-for-fee plan	3,079	—	76	—	—	76
Balance, September 30, 2009	92,551,709	$463	$1,791,129	$(20,184)	$ 405,353	$2,176,761

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2009	2008	2007
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 190,978	$ 180,331	$ 168,492
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	5,382	—	6,344
Depreciation and amortization:			
Charged to depreciation and amortization	217,208	200,442	198,863
Charged to other accounts	94	147	192
Deferred income taxes	129,759	97,940	62,121
Stock-based compensation	14,494	14,032	11,934
Debt financing costs	10,364	10,665	10,852
Other	(1,177)	(5,492)	(1,516)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	244,713	(97,018)	(6,407)
(Increase) decrease in gas stored underground	194,287	(54,726)	(12,317)
(Increase) decrease in other current assets	117,737	(120,882)	71,279
(Increase) decrease in deferred charges and other assets	(106,231)	22,476	23,506
Increase (decrease) in accounts payable and accrued liabilities	(181,978)	39,902	(8,428)
Increase (decrease) in other current liabilities	(717)	60,026	11,661
Increase in deferred credits and other liabilities	84,320	23,090	10,519
Net cash provided by operating activities	919,233	370,933	547,095
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(509,494)	(472,273)	(392,435)
Other, net	(7,707)	(10,736)	(10,436)
Net cash used in investing activities	(517,201)	(483,009)	(402,871)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	(283,981)	200,174	(213,242)
Net proceeds from issuance of long-term debt	445,623	—	247,217
Settlement of Treasury lock agreement	1,938	—	4,750
Repayment of long-term debt	(407,353)	(10,284)	(303,185)
Cash dividends paid	(121,460)	(117,288)	(111,664)
Issuance of common stock	27,687	25,466	24,897
Net proceeds from equity offering	—	—	191,913
Net cash provided by (used in) financing activities	(337,546)	98,068	(159,314)
Net increase (decrease) in cash and cash equivalents	64,486	(14,008)	(15,090)
Cash and cash equivalents at beginning of year	46,717	60,725	75,815
Cash and cash equivalents at end of year	$ 111,203	$ 46,717	$ 60,725

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 over 3 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 locations 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, a division of the Company. This 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 our 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 managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Colorado-Kansas, Kentucky/Mid-States and Louisiana 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 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 and for our natural gas marketing segment, and, on a more limited basis, to 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.

2. Summary of Significant Accounting Policies

Principles of consolidation — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligations, impairment of long-lived assets, risk management and trading activities, fair value measurements and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results could differ from those estimates.

Regulation — Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. 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 regulatory assets as a component of other current assets and deferred charges and other assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded either on the face of the balance sheet or as a component of current liabilities, deferred income taxes or deferred credits and other liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2009 and 2008 included the following:

	September 30	
	2009	2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$197,743	$100,563
Merger and integration costs, net	7,161	7,586
Deferred gas costs	22,233	55,103
Environmental costs	866	980
Rate case costs	5,923	12,885
Deferred franchise fees	10,014	651
Deferred income taxes, net	639	343
Other	6,218	8,120
	$250,797	$186,231
Regulatory liabilities:		
Deferred gas costs	$110,754	$ 76,979
Regulatory cost of removal obligation	335,428	317,273
Other	7,960	5,639
	$454,142	$399,891

Currently authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions. During the fiscal years ended September 30, 2009, 2008 and 2007, we recognized $0.4 million, $0.4 million and $0.3 million in amortization expense related to these costs.

Revenue recognition — Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. During the year ended September 30, 2009 we recognized a non-recurring $7.6 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.

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by accounting principles generally accepted in the United States, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas cost adjustment mechanisms. Purchased gas cost adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. There is no gross profit generated through purchased gas cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our natural gas distribution segment's gas costs. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our natural gas marketing segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2009, 2008 and 2007, we included unrealized gains (losses) on open contracts of $(28.4) million, $25.5 million and $18.4 million as a component of natural gas marketing revenues.

Operating revenues for our regulated transmission and storage and pipeline, storage and other segments are recognized in the period in which actual volumes are transported and storage services are provided.

Cash and cash equivalents — We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts — Accounts receivable arise from natural gas sales to residential, commercial, industrial, municipal and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our natural gas distribution operations and natural gas held by our natural gas marketing and other nonregulated subsidiaries to conduct their operations. The average cost method is used for all our regulated operations, except for certain jurisdictions in the Kentucky/Mid-States Division, where it is valued on the first-in first-out method basis, in accordance with regulatory requirements. Our natural gas marketing and pipeline, storage and other segments utilize the average cost method; however, most of this inventory is hedged and is therefore reported at fair value at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Regulated property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $4.9 million, $2.9 million and $3.0 million was capitalized in 2009, 2008 and 2007.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not recoverable through rates are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the regulated plant in service account included in the rate base and depreciation begins.

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.8 percent, 3.7 percent and 3.9 percent for the fiscal years ended September 30, 2009, 2008 and 2007.

Nonregulated property, plant and equipment — Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 35 years.

Asset retirement obligations — We record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense.

As of September 30, 2009 and 2008, we recorded asset retirement obligations of $13.0 million and $5.9 million. Additionally, we recorded $3.9 million and $1.3 million of asset retirement costs as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

We believe we have a legal obligation to retire our natural gas storage wells when we take them out of service period permanently. However, we have not recognized an asset retirement obligation associated with our storage wells because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage wells out of service permanently. Therefore, we cannot reasonably estimate the fair value of this obligation.

Impairment of long-lived assets — We periodically evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded.

During fiscal 2007, we recorded a $6.3 million charge associated with the write-off of approximately $3.0 million of costs related to a nonregulated natural gas gathering project and approximately $3.3 million of obsolete software costs.

Goodwill and intangible assets — We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Intangible assets are amortized over their useful lives of 10 years. These assets are reviewed for impairment as impairment indicators arise. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. No impairment has been recognized.

Marketable securities — As of September 30, 2009 and 2008, all of our marketable securities were classified as available-for-sale. In accordance with the authoritative accounting standards, 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.

Due to the deterioration of the financial markets in late calendar 2008 and early calendar 2009 and the uncertainty of a full recovery of these investments given the current economic environment, we recorded a $5.4 million noncash charge to impair certain available-for-sale investments during fiscal 2009.

Financial instruments and hedging activities — We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically use financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored for our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution, natural gas marketing and pipeline, storage and other segments. The objectives and strategies for the use of financial instruments are discussed in Note 4.

We record all of our financial instruments on the balance sheet at fair value, with changes in fair value ultimately recorded in the income statement. These financial instruments are reported as risk management assets and liabilities and are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying financial instrument.

The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our natural gas distribution segment, 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 accounting principles generally accepted in the United States. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

In our natural gas marketing and pipeline, storage and other segments, we have designated the natural gas inventory held by these operating segments as the hedged item in a fair-value hedge. This 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 or losses in revenue in the period of change. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges and are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in revenue 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 (NYMEX) and the market (spot) prices used to value our physical storage (Gas Daily) 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. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges.

Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

In our natural gas marketing segment, we have elected to treat fixed-price forward contracts to deliver natural gas as normal purchases and normal sales. As such, these deliveries are recorded on an accrual basis in accordance with our revenue recognition policy. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on these open financial instruments are recorded as a component of accumulated other comprehensive income, and are recognized in earnings as a component of revenue when the hedged volumes are sold. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Gains and losses from hedge ineffectiveness are recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the financial instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges 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 are referred to as timing ineffectiveness.

In our natural gas marketing segment, we also utilize master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. The Company adopted this standard as of September 30, 2008. As of September 30, 2009 and 2008, the Company netted $11.7 million and $56.6 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt. Currently, we do not have any financial instruments in place to manage interest rate risk. However, in prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as a cash flow hedge of an anticipated transaction at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement.

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 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 current accounting standards. 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.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. 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.

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) 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.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Through fiscal 2008, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. To comply with the new measurement date requirements established by the Financial Accounting Standards Board (FASB) and incorporated into accounting principles generally accepted in the United States, effective October 1, 2008, we changed our measurement date from June 30 to our fiscal year end, September 30. This change is more fully discussed in Note 8. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of the annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our annual postretirement net cost based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon the annual review of our participant census information as of the measurement date.

Income taxes — Income taxes are provided based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on current and accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

The Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements.

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

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

	September 30	
	2009	2008
	(In thousands)	
Unrealized holding gains on investments	$ 2,460	$ 910
Treasury lock agreements	(7,498)	(11,104)
Cash flow hedges	(15,146)	(25,753)
	$(20,184)	$(35,947)

Subsequent events — In May 2009, the FASB issued guidance related to subsequent events which 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. Companies are required 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 this guidance as of June 30, 2009.

We have evaluated subsequent events from the September 30, 2009 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. No events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — In June 2009, the FASB issued an update to the accounting for transfers of financial assets. This guidance clarifies the information that must be disclosed related to a transfer of financial assets; the effects of a transfer on the transferor's financial position, financial performance, and cash flows; and a transferor's continuing involvement, if any, in transferred financial assets. The standard also removes the concept of a qualifying special-purpose entity for accounting purposes. Therefore, after the effective date, formerly qualifying special-purpose entities (as defined under previous accounting standards) must be evaluated for consolidation by companies on and after the effective date in accordance with the applicable consolidation guidance. The provisions of this standard will be effective for us beginning October 1, 2009. The adoption of this standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued an update to the criteria used to determine if an entity has a controlling interest in a variable interest entity. The updated criteria are intended to be primarily qualitative and result in a more effective method for identifying which enterprise has a controlling financial interest in a variable interest entity. Additionally, the standard enhances the disclosure requirements for entities that hold a variable interest in a variable interest entity. The provisions of this standard will be effective for us beginning October 1, 2009. The adoption of this standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued the *FASB Accounting Standards Codification* (Codification) which supersedes all existing non-SEC accounting and reporting standards and becomes the source of authoritative U.S. generally accepted accounting principles (GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. All other nongrandfathered non-SEC accounting literature not included in the Codification will become nonauthoritative upon the effective date. The Codification is effective for us for the year ended September 30, 2009. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows.

In December 2008, the FASB issued guidance which requires employers to disclose information about fair value measurements of plan 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. The provisions of this standard will be effective for us beginning October 1, 2009. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In June 2008, the FASB issued guidance related to determining whether instruments granted in share-based payment transactions are participating securities. Based on this guidance, the Company will include non-vested shares granted under its 1998 Long-Term Incentive Plan in the basic earnings per share calculation. The provisions of this standard will be effective for us beginning October 1, 2009, at which time all prior-period earnings per share data will be adjusted. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In April 2008, the FASB issued guidance which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of intangible assets. The objective of the standard is to better match the useful life of intangible assets to the cash flow generated. The provisions of this standard will be effective for us beginning October 1, 2009. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued an update to business combination accounting. The new pronouncement establishes 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 could impact income tax expense. The provisions of this standard will apply to any acquisitions we complete after October 1, 2009.

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. The provisions of the standard will be effective for us beginning October 1, 2009. This standard is not expected to have a material impact on our financial position, results of operations or cash flows.

3. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2009 and 2008.

	September 30	
	2009	2008
	(In thousands)	
Goodwill	$738,603	$736,998
Intangible assets	1,461	2,088
Total	$740,064	$739,086

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2009:

	Natural Gas Distribution Segment	Regulated Transmission and Storage Segment	Natural Gas Marketing Segment	Pipeline, Storage and Other Segment	Total
			(In thousands)		
Balance as of September 30, 2008	$569,920	$132,367	$24,282	$10,429	$736,998
Deferred tax adjustments on prior acquisitions[(1)]	1,672	(67)	—	—	1,605
Balance as of September 30, 2009	$571,592	$132,300	$24,282	$10,429	$738,603

(1) During the preparation of the fiscal 2009 tax provision, we adjusted certain deferred taxes recorded in connection with acquisitions completed in fiscal 2001 and fiscal 2004, which resulted in an increase to goodwill and net deferred tax liabilities of $1.6 million.

Information regarding our intangible assets is reflected in the following table. As of September 30, 2009 and 2008, we had no intangible assets with indefinite lives.

		September 30, 2009			September 30, 2008		
	Useful Life (Years)	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
				(In thousands)			
Customer contracts	10	$6,926	$(5,465)	$1,461	$6,926	$(4,838)	$2,088

The following table presents actual amortization expense recognized during 2009 and an estimate of future amortization expense based upon our intangible assets at September 30, 2009.

Amortization expense (in thousands):	
Actual for the fiscal year ending September 30, 2009	$627
Estimated for the fiscal year ending:	
September 30, 2010	627
September 30, 2011	627
September 30, 2012	43
September 30, 2013	43
September 30, 2014	43

4. 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. 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.

As discussed in Note 2, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2009 and 2008:

	Natural Gas Distribution	Natural Gas Marketing	Total
		(In thousands)	
September 30, 2009:			
Assets from risk management activities, current[1]	$ 4,395	$27,248	$ 31,643
Assets from risk management activities, noncurrent	1,620	12,415	14,035
Liabilities from risk management activities, current	(20,181)	(1,301)	(21,482)
Liabilities from risk management activities, noncurrent	—	—	—
Net assets (liabilities)	$(14,166)	$38,362	$ 24,196
September 30, 2008:			
Assets from risk management activities, current[2]	$ —	$68,291	$ 68,291
Assets from risk management activities, noncurrent	—	5,473	5,473
Liabilities from risk management activities, current[2]	(58,566)	(348)	(58,914)
Liabilities from risk management activities, noncurrent	(5,111)	(258)	(5,369)
Net assets (liabilities)	$(63,677)	$73,158	$ 9,481

(1) Includes $11.7 million of cash held on deposit to collateralize certain financial instruments which is classified as current risk management assets.

(2) Includes $56.6 million of cash held on deposit in margin accounts to collateralize certain financial instruments. Of this amount, $29.8 million was used to offset current risk management liabilities under master netting agreements and the remaining $26.8 million is classified as current risk management assets.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our natural gas distribution 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 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 planned winter flowing gas requirements at a weighted average cost of approximately $10.15 per Mcf.

We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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 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 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. 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. Future 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, and 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. 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 September 30, 2009, AEH had a net open position (including existing storage) of 0.4 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.

In fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the-then anticipated issuance of $875 million of long-term debt issued in October 2004 in connection with the permanent financing for our TXU Gas acquisition. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties.

In March 2007, we entered into a Treasury lock agreement to fix the Treasury yield component of the interest cost associated with $100 million of our $250 million 6.35% Senior Notes issued in June 2007. This Treasury lock agreement was settled in June 2007, which resulted in the receipt of $2.9 million from the counterparties.

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) issued on March 23, 2009. The Senior Notes Offering is discussed in Note 6. We designated this Treasury lock as a cash flow hedge of an anticipated transaction. This Treasury lock agreement 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.

The gains and losses realized upon settlement 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.

Quantitative Disclosures Related to Financial Instruments

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

As of September 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 September 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	—	(15,623)	(2,550)
	Cash Flow	—	32,874	(4,267)
	Not designated	32,369	83,384	(499)
		32,369	100,635	(7,316)

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 September 30, 2009 and 2008. 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 $11.7 million and $56.6 million of cash held on deposit in margin accounts as of September 30, 2009 and 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 consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 5.

	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.

	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	—	20,104	20,104
Noncurrent commodity contracts	Deferred charges and other assets	—	999	999
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 consolidated income statement, by operating segment, as applicable, for the years ended September 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 years ended September 30, 2009 and 2008 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $6.4 million and $46.0 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 consolidated income statement for the years ended September 30, 2009 and 2008 is presented below.

	Fiscal Year Ended September 30, 2009		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$ 37,967	$ 7,153	$ 45,120
Fair value adjustment for natural gas inventory designated as the hedged item	(25,501)	(3,330)	(28,831)
Total impact on revenue	$ 12,466	$ 3,823	$ 16,289
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 5,958	$ —	$ 5,958
Timing ineffectiveness	6,508	3,823	10,331
	$ 12,466	$ 3,823	$ 16,289

	Fiscal Year Ended September 30, 2008		
	Natural Gas Marketing	Pipeline, Storage and Other	Consolidated
		(In thousands)	
Commodity contracts	$30,572	$4,941	$35,513
Fair value adjustment for natural gas inventory designated as the hedged item	6,281	482	6,763
Total impact on revenue	$36,853	$5,423	$42,276
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ (2,841)	$ —	$ (2,841)
Timing ineffectiveness	39,694	5,423	45,117
	$36,853	$5,423	$42,276

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 consolidated income statements for the years ended September 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.

	Fiscal Year Ended September 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	$ —	$(162,283)	$25,743	$(136,540)
Loss arising from ineffective portion of commodity contracts	—	(9,888)	—	(9,888)
Total impact on revenue	—	(172,171)	25,743	(146,428)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(4,070)	—	—	(4,070)
Total Impact from Cash Flow Hedges	$(4,070)	$(172,171)	$25,743	$(150,498)

	Fiscal Year Ended September 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	$ —	$(12,739)	$9,468	$(3,271)
Gain arising from ineffective portion of commodity contracts	—	3,720	—	3,720
Total impact on revenue	—	(9,019)	9,468	449
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(5,076)	—	—	(5,076)
Total Impact from Cash Flow Hedges	$(5,076)	$ (9,019)	$9,468	$(4,627)

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 fiscal years ended September 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.

	Fiscal Year Ended September 30	
	2009	2008
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$ 1,221	$ —
Forward commodity contracts	(72,683)	(23,029)
Recognition of losses in earnings due to settlements:		
Treasury lock agreements	2,385	3,148
Forward commodity contracts	83,290	2,029
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ 14,213	$(17,852)

(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 September 30, 2009:

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
2010	$(1,687)	$(15,272)	$(16,959)
2011	(1,687)	(408)	(2,095)
2012	(1,687)	39	(1,648)
2013	(1,687)	214	(1,473)
2014	(1,687)	281	(1,406)
Thereafter	937	—	937
Total[(1)]	$(7,498)	$(15,146)	$(22,644)

(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 consolidated income statements for the fiscal years ended September 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.

	Fiscal Year Ended September 30	
	2009	2008
	(In thousands)	
Natural gas marketing commodity contracts	$43,483	$(37,200)
Pipeline, storage and other commodity contracts	(6,614)	1,139
Total impact on revenue	$36,869	$(36,061)

5. Fair Value Measurements

In September 2006, the FASB issued authoritative accounting literature that defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. This guidance 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 this guidance on October 1, 2008 for most of the financial assets and liabilities recorded on our balance sheet at fair value. Adoption of this guidance for these assets and liabilities did not have a material impact on our financial position, results of operations or cash flows. Subsequent to the issuance of the guidance related to fair value measurements, the FASB provided a one-year deferral for nonrecurring fair value measurements associated with our nonfinancial assets and liabilities. Under this partial deferral, the guidance related to fair value measurements 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 the FASB's fair value guidance 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.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The adoption of the authoritative accounting literature published by the FASB in September 2006 did not affect these valuations because pension and post-retirement assets were specifically excluded from its prescribed disclosure provisions. Accordingly, these plan assets are not included in the tabular disclosures below. However, in December 2008, the FASB issued additional guidance, which will, among other things, require similar disclosure about fair value measurements for our pension plan assets. This guidance will impact our annual disclosure requirements beginning in fiscal 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. 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 September 30, 2009. 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)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[1]	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[2]	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) 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, 2009, we had $11.7 million of cash held in margin accounts to collateralize certain financial instruments which 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 financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The nonfinancial assets and liabilities include 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 third party market value quotations. The following table presents the carrying value and fair value of our debt as of September 30, 2009:

	September 30, 2009 (In thousands)
Carrying Amount	$2,172,827
Fair Value	$2,317,572

6. Debt

Long-term debt

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

	2009	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
Rental property, propane and other term notes due in installments through 2013	524	1,309
Total long-term debt	2,172,827	2,123,612
Less:		
Original issue discount on unsecured senior notes and debentures	(3,296)	(3,035)
Current maturities	(131)	(785)
	$2,169,400	$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 4. 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 September 30, 2009, there was $72.6 million outstanding under our commercial paper program. 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. As of September 30, 2009, our commercial paper had maturities of one day with an interest rate of 0.25 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 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 September 30, 2009, there were no borrowings under this facility, but we had $72.6 million of commercial paper outstanding leaving $494.1 million 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 September 30, 2009, there were no borrowings outstanding under this facility. In October 2009, this facility was renewed on substantially the same terms for $200 million, which expires October 2010.

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 September 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 September 30, 2009, our total-debt-to-total-capitalization ratio, as defined, was 53 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 $86.4 million outstanding under this facility at September 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 September 30, 2009, there were no borrowings outstanding under this credit facility. However, at September 30, 2009, AEM letters of credit totaling $19.2 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 $170.4 million at September 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 September 30, 2009, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.84 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 September 30, 2009, AEM's net working capital was $155.9 million and its tangible net worth was $168.5 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 September 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 September 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 September 30, 2009, we had approximately $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 $200 million of equity securities and $250 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 September 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.

Maturities of long-term debt at September 30, 2009 were as follows (in thousands):

2010	$ 131
2011	360,131
2012	2,434
2013	250,131
2014	—
Thereafter	1,560,000
	$2,172,827

7. Stock and Other Compensation Plans

Stock-Based Compensation Plans

Total stock-based compensation expense was $14.5 million, $14.0 million and $11.9 million for the fiscal years ended September 30, 2009, 2008 and 2007, primarily related to restricted stock costs.

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan (LTIP), which became effective in October 1998 after approval by our shareholders. The LTIP is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock.

We are authorized to grant awards for up to a maximum of 6.5 million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2009, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 1,473,531 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years. However, no stock options have been granted under this plan since fiscal 2003, except for a limited number of options that were converted from bonuses paid under our Annual Incentive Plan, the last of which occurred in fiscal 2006.

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The associated expense is recognized ratably over the vesting period. The following summarizes information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2009, 2008 and 2007:

	2009		2008		2007	
	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of year	1,096,770	$29.04	948,717	$28.95	746,776	$26.49
Granted	711,909	25.76	547,845	27.90	485,260	30.85
Vested	(499,267)	29.05	(380,895)	27.17	(271,075)	26.12
Forfeited	(13,571)	28.92	(18,897)	29.32	(12,244)	28.51
Nonvested at end of year	1,295,841	$27.23	1,096,770	$29.04	948,717	$28.95

As of September 30, 2009, there was $17.1 million of total unrecognized compensation cost related to nonvested restricted shares granted under the LTIP. That cost is expected to be recognized over a weighted-average period of 1.5 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2009, 2008 and 2007 was $14.5 million, $10.3 million and $7.1 million.

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2009		2008		2007	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	913,841	$22.54	920,841	$22.54	1,017,152	$22.57
Granted	—	—	—	—	—	—
Exercised	(130,965)	21.99	(7,000)	21.90	(92,071)	22.84
Forfeited	—	—	—	—	(4,240)	23.11
Expired	(171,649)	25.31	—	—	—	—
Outstanding at end of year(1)	611,227	$21.88	913,841	$22.54	920,841	$22.54
Exercisable at end of year(2)	611,227	$21.88	911,492	$22.53	908,332	$22.49

(1) The weighted-average remaining contractual life for outstanding options was 2.4 years, 3.4 years, and 4.4 years for fiscal years 2009, 2008 and 2007. The aggregate intrinsic value of outstanding options was $2.1 million, $3.3 million and $3.3 million for fiscal years 2009, 2008 and 2007.

(2) The weighted-average remaining contractual life for exercisable options was 2.4 years, 3.4 years, and 4.3 years for fiscal years 2009, 2008 and 2007. The aggregate intrinsic value of exercisable options was $2.1 million, $3.3 million and $3.3 million for fiscal years 2009, 2008 and 2007.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2009, is reflected in the following tables:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (In years)	Weighted Average Exercise Price
\$15.65 to \$20.24	52,000	0.4	\$15.66
\$20.25 to \$22.99	406,470	2.7	\$21.88
\$23.00 to \$26.19	152,757	2.1	\$24.00
\$15.65 to \$26.19	611,227	2.4	\$21.88

	Fiscal Year Ended September 30		
	2009	2008	2007
	(In thousands, except per share data)		
Grant date weighted average fair value per share	—	—	—
Net cash proceeds from stock option exercises	\$2,880	\$153	\$2,103
Income tax benefit from stock option exercises	\$ 177	\$ 12	\$ 296
Total intrinsic value of options exercised	\$ 262	\$ 26	\$ 347

As of September 30, 2009, there was no unrecognized compensation cost related to nonvested stock options.

Other Plans

Direct Stock Purchase Plan

We maintain a Direct Stock Purchase Plan, open to all investors, which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. The minimum initial investment required to join the plan is \$1,250. Direct Stock Purchase Plan participants may purchase additional shares of our common stock as often as weekly with voluntary cash payments of at least \$25, up to an annual maximum of \$100,000.

Outside Directors Stock-For-Fee Plan

In November 1994, the Board adopted the Outside Directors Stock-for-Fee Plan which was approved by our shareholders in February 1995 and was amended and restated in November 1997. The plan permits non-employee directors to receive all or part of their annual retainer and meeting fees in stock rather than in cash.

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

In November 1998, the Board of Directors adopted the Equity Incentive and Deferred Compensation Plan for Non-Employee Directors which was approved by our shareholders in February 1999. This plan amended the Atmos Energy Corporation Deferred Compensation Plan for Outside Directors adopted by the Company in May 1990 and replaced the pension payable under our Retirement Plan for Non-Employee Directors. The plan provides non-employee directors of Atmos Energy with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company, invest deferred compensation into either a cash account or a stock account and to receive an annual grant of share units for each year of service on the Board.

Other Discretionary Compensation Plans

We adopted the Variable Pay Plan in fiscal 1999 for our regulated segments' employees to give each employee an opportunity to share in our financial success based on the achievement of key performance measures considered critical to achieving business objectives for a given year and has minimum and maximum thresholds. The plan must meet the minimum threshold for the plan to be funded and distributed to employees. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded. During the last several fiscal years, we have used earnings per share as our sole performance measure.

We adopted our Annual Incentive Plan in October 2001 to give the employees in our nonregulated segments an opportunity to share in the success of the nonregulated operations. The plan is based upon the net earnings of the nonregulated operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

8. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover substantially all of our employees. We also maintain post-retirement plans that provide health care benefits to retired employees. Finally, we sponsor defined contribution plans which cover substantially all employees. These plans are discussed in further detail below.

Effective September 30, 2007, we adopted the guidance issued by the FASB in September 2006 related to changes in the accounting rules for defined benefit pension and other postretirement plans. The new standard made a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity.

Additionally, this standard requires that our measurement date correspond to the fiscal year end balance sheet date. Effective October 1, 2008, the Company adopted the measurement date requirement 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 the new standard, the impact of changing the measurement date 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 as of October 1, 2008.

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. Therefore, the decrease in the unrecognized actuarial loss that would have been recorded as a component of accumulated other comprehensive loss, net of tax, was recorded as a reduction to a regulatory asset as a component of deferred charges and other assets in fiscal 2009. The change in the measurement date did not materially impact the level of net periodic pension cost we recorded in fiscal 2009.

The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets are as follows:

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2009				
Unrecognized transition obligation	$ —	$ —	$ 6,242	$ 6,242
Unrecognized prior service cost	(1,802)	187	(11,761)	(13,376)
Unrecognized actuarial loss	150,989	29,709	24,179	204,877
	$149,187	$29,896	$ 18,660	$197,743
September 30, 2008				
Unrecognized transition obligation	$ —	$ —	$ 8,131	$ 8,131
Unrecognized prior service cost	(2,984)	452	—	(2,532)
Unrecognized actuarial loss	64,815	17,308	12,841	94,964
	$ 61,831	$17,760	$ 20,972	$100,563

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2009, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan that was established effective January 1999 and covers substantially all employees of Atmos Energy's regulated operations. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay).

The Plan also provides for an additional annual allocation based upon a participant's age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan credited this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applied through December 31, 2008, for participants who were at least age 50 as of January 1, 1999, and who were participants in one of the prior plans on December 31, 1998. Participants are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity.

The Union Plan is a defined benefit plan that covers substantially all full-time union employees in our Mississippi Division. Under this plan, benefits are based upon years of benefit service and average final earnings. Participants vest in the plan after five years and will receive their benefit in an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974, including the funding requirements under the Pension Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2009, we contributed $21.0 million in cash to the Plans to achieve a desired level of funding for the 2008 plan year while maximizing the tax deductibility of this payment. In fiscal 2008, we voluntarily contributed $2.3 million to the Union Plan, which achieved the desired level of funding for this plan for the 2007 plan year. During fiscal 2007, we did not make any contributions to the Plans. Based upon market conditions subsequent to September 30, 2009, the current funded position of the plans and the new funding requirements under the PPA, we believe it is reasonably possible that we will be required to contribute to the Plans in fiscal 2010. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. However, we cannot anticipate with certainty whether such contributions will be made and the amount of such contributions.

We manage the Master Trust's assets with the objective of achieving a rate of return net of inflation of approximately four percent per year. We make investment decisions and evaluate performance on a medium term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long-term asset investment policy adopted by the Board of Directors.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds, other investment assets and cash and cash equivalents. Investments in equity securities are diversified among the market's various subsectors in an effort to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

The following table presents asset allocation information for the Master Trust as of September 30, 2009 and 2008.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2009	Actual Allocation September 30 2008
Domestic equities	35%-55%	38.5%	42.0%
International equities	10%-20%	12.8%	11.0%
Fixed income	10%-30%	19.6%	24.2%
Company stock	0%-10%	10.9%	10.2%
Other assets	10%-20%	18.2%	12.6%

At September 30, 2009 and 2008, the Plan held 1,169,700 shares of our common stock, which represented 10.9 percent and 10.2 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.5 million during fiscal 2009 and 2008.

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a September 30 measurement date. Prior to October 1, 2008, the estimates and assumptions were determined based on a June 30 measurement date. As described above, the adoption of new accounting guidance in accordance with accounting principles generally accepted in the United States necessitated a change in our measurement date during fiscal 2009. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plans were determined as of September 30, 2009 and June 30, 2008 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2008, June 30, 2007 and 2006. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2009	2008	2009	2008	2007
Discount rate	5.52%	6.68%	7.57%	6.30%	6.30%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.25%	8.25%	8.25%	8.25%

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2009 and 2008 based upon a September 30, 2009 and June 30, 2008 measurement date.

	2009	2008
	(In thousands)	
Accumulated benefit obligation	$366,770	$329,023
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$337,640	$335,581
Measurement date change	(18,446)	—
Service cost	12,951	13,329
Interest cost	24,060	21,129
Actuarial loss (gain)	49,807	(6,939)
Benefits paid	(25,967)	(25,721)
Plan amendments	—	261
Benefit obligation at end of year	380,045	337,640
Change in plan assets:		
Fair value of plan assets at beginning of year	341,380	389,073
Measurement date change	(34,935)	—
Actual return on plan assets	(332)	(21,972)
Employer contributions[1]	21,000	—
Benefits paid	(25,967)	(25,721)
Fair value of plan assets at end of year	301,146	341,380
Reconciliation:		
Funded status	(78,899)	3,740
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(78,899)	$ 3,740

(1) During the fourth quarter of fiscal 2008, we voluntarily contributed $2.3 million to the Union Plan. However, this contribution was not reflected in this table for the 2008 period because it occurred after the June 30, 2008 measurement date. It is reflected in the 2009 period as a portion of the measurement date change in both the benefit obligation and the fair value of plan assets rollforwards as this represents the period from June 30, 2008 to September 30, 2009.

Net periodic pension cost for the Plans for fiscal 2009, 2008 and 2007 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2009	2008	2007
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 12,951	$ 13,329	$ 13,090
Interest cost	24,060	21,129	20,396
Expected return on assets	(24,950)	(25,242)	(24,357)
Amortization of prior service cost	(946)	(897)	(838)
Recognized actuarial loss	3,742	6,482	8,253
Net periodic pension cost	$ 14,857	$ 14,801	$ 16,544

Supplemental Executive Benefits Plans

We have a nonqualified Supplemental Executive Benefits Plan which provides additional pension, disability and death benefits to our officers, division presidents and certain other employees of the Company who were employed on or before August 12, 1998. In addition, in August 1998, we adopted the Supplemental Executive Retirement Plan (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

During the last fiscal year, the Company has worked with our independent compensation consultant to develop and implement a new Supplemental Executive Retirement Plan (SERP) design for any new executives or current employees selected for participation in the SERP arrangement on a prospective basis. Only those executives who are currently members of our Management Committee as well as those individuals who may be selected in the future to serve on the Management Committee, plus those executives who are active SERP participants as of August 5, 2009, will continue to participate in the current SERP arrangement until their respective retirement dates. The current SERP arrangement is a 60 percent of covered compensation defined benefit arrangement in which benefits from the underlying qualified defined benefit plan are an offset to the SERP benefit. The new SERP arrangement for new participants in the Company's executive retirement program is a modified defined benefit approach in which the Company will contribute to a nominal account for each participant, an amount equal to ten percent of each participant's base salary and bonus following the participant's completion of a plan year of service. Other provisions of the plan mirror that of the Company's underlying qualified plan, the Pension Account Plan. At this time, only one employee has been selected for participation in the new SERP arrangement.

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of September 30, 2009 and June 30, 2008 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2008, June 30, 2007 and 2006. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2009	2008	2009	2008	2007
Discount rate	5.52%	6.68%	7.57%	6.30%	6.30%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2009 and 2008, based upon a September 30, 2009 and June 30, 2008 measurement date.

	2009	2008
	(In thousands)	
Accumulated benefit obligation	$ 93,906	$ 83,871
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 91,986	$ 92,350
Measurement date change	(8,569)	—
Service cost	1,985	2,184
Interest cost	6,056	5,816
Actuarial loss (gain)	22,366	(3,634)
Benefits paid	(12,722)	(4,730)
Curtailment	1,645	—
Benefit obligation at end of year	102,747	91,986
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	12,722	4,730
Benefits paid	(12,722)	(4,730)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(102,747)	(91,986)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(102,747)	$(91,986)

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 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
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

Due to the deterioration of the financial markets in late calendar 2008 and early calendar 2009 and the uncertainty of a full recovery of these investments given the current economic environment, we recorded a

$5.4 million noncash charge to impair certain available-for sale investments during the year ended September 30, 2009. As a result of this impairment and the recent improvement in market conditions, at September 30, 2009, we did not maintain any investments that are in an unrealized loss position.

Net periodic pension cost for the supplemental plans for fiscal 2009, 2008 and 2007 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2009	2008	2007
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 1,985	$2,184	$ 2,981
Interest cost	6,056	5,816	5,585
Amortization of transition asset	—	—	—
Amortization of prior service cost	212	212	1,020
Recognized actuarial loss	324	1,222	1,482
Curtailment	1,645	—	—
Net periodic pension cost	$10,222	$9,434	$11,068

Supplemental Disclosures for Defined Benefit Plans with Accumulated Benefit Obligations in Excess of Plan Assets

The following summarizes key information for our defined benefit plans with accumulated benefit obligations in excess of plan assets. For fiscal 2009 and 2008 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Supplemental Plans	
	2009	2008
	(In thousands)	
Projected Benefit Obligation	$102,747	$91,986
Accumulated Benefit Obligation	93,906	83,871
Fair Value of Plan Assets	—	—

Estimated Future Benefit Payments

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Pension Plans	Supplemental Plans
	(In thousands)	
2010	$ 31,334	$21,410
2011	30,633	4,511
2012	30,806	10,527
2013	31,099	6,664
2014	31,467	4,664
2015-2019	168,140	37,965

Postretirement Benefits

We sponsor the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the Atmos Retiree Medical Plan). This plan provides medical and prescription drug protection to all qualified participants based on their date of retirement. The Atmos Retiree Medical Plan provides different levels of benefits depending on the level of coverage chosen by the participants and the terms of predecessor plans; however, we generally pay 80 percent of the projected net claims and administrative costs and participants pay the remaining 20 percent of this cost.

As of September 30, 2009, the Board of Directors approved a change to the cost sharing methodology for employees who had not met the participation requirements by that date for the Atmos Retiree Medical Plan. Starting in five years, on January 1, 2015, the contribution rates that will apply to all non-grandfathered participants will be determined using a new cost sharing methodology by which Atmos Energy will limit its contribution to a three percent cost increase in claims and administrative costs each year. If medical costs covered by the Atmos Retiree Medical Plan increase more than three percent annually, participants will be responsible for the additional cost.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute $12.2 million to our postretirement benefits plan during fiscal 2010.

We maintain a formal investment policy with respect to the assets in our postretirement benefits plan to ensure the assets funding the postretirement benefit plan are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the postretirement benefits plan.

We currently invest the assets funding our postretirement benefit plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2009 and 2008.

	Actual Allocation September 30	
Security Class	**2009**	**2008**
Diversified investment funds	98.1%	98.1%
Cash and cash equivalents	1.9%	1.9%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of September 30, 2009 and June 30, 2008 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2008, June 30, 2007 and 2006. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2009	2008	2009	2008	2007
Discount rate	5.52%	6.68%	7.57%	6.30%	6.30%
Expected return on plan assets	5.00%	5.00%	5.00%	5.00%	5.20%
Initial trend rate	7.50%	8.00%	8.00%	8.00%	8.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2014	2014	2015	2011	2010

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2009 and 2008, based upon a September 30, 2009 and June 30, 2008 measurement date.

	2009	2008
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 193,997	$ 175,585
Measurement date change	(15,024)	—
Service cost	11,786	13,367
Interest cost	14,080	11,648
Plan participants' contributions	2,741	2,879
Actuarial loss (gain)	24,334	1,401
Benefits paid	(10,537)	(11,008)
Subsidy payments	116	125
Plan amendments	(11,761)	—
Benefit obligation at end of year	209,732	193,997
Change in plan assets:		
Fair value of plan assets at beginning of year	48,072	55,370
Measurement date change	(4,128)	—
Actual return on plan assets	1,394	(8,782)
Employer contributions	10,104	9,613
Plan participants' contributions	2,741	2,879
Benefits paid	(10,537)	(11,008)
Fair value of plan assets at end of year	47,646	48,072
Reconciliation:		
Funded status	(162,086)	(145,925)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$(162,086)	$(145,925)

Net periodic postretirement cost for fiscal 2009, 2008 and 2007 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2009	2008	2007
	(In thousands)		
Components of net periodic postretirement cost:			
Service cost	$11,786	$13,367	$11,228
Interest cost	14,080	11,648	10,561
Expected return on assets	(2,292)	(2,861)	(2,388)
Amortization of transition obligation	1,511	1,511	1,512
Amortization of prior service cost	—	—	33
Net periodic postretirement cost	$25,085	$23,665	$20,946

Assumed health care cost trend rates have a significant effect on the amounts reported for the plan. A one-percentage point change in assumed health care cost trend rates would have the following effects on the latest actuarial calculations:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 3,740	$ (3,106)
Effect on postretirement benefit obligation	$24,463	$(20,692)

We are currently recovering other postretirement benefits costs through our regulated rates under accrual accounting as prescribed by accounting principles generally accepted in the United States in substantially all of our service areas. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Kentucky/Mid-States Division and our Mississippi Division or have been included in a rate case and not disallowed. Management believes that this accounting method is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

Estimated Future Benefit Payments

The following benefit payments paid by us, retirees and prescription drug subsidy payments for our postretirement benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
	(In thousands)			
2010	$12,242	$ 2,740	$ 92	$ 15,074
2011	10,696	3,179	76	13,951
2012	12,161	3,596	87	15,844
2013	13,519	4,008	100	17,627
2014	15,167	4,531	115	19,813
2015-2019	98,997	33,946	62	133,005

Defined Contribution Plans

As of September 30, 2009, we maintained three defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan), the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan) and the Atmos Energy Marketing, LLC 401K Profit-Sharing Plan (the AEM 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

The Union 401K Plan covers substantially all Mississippi Division employees who are members of the International Chemical Workers Union Council, United Food and Commercial Workers Union International (the Union) and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Employees of the Union automatically become participants of the Union 401K plan on the date of union membership. We match 50 percent of a participant's contribution in cash, limited to six percent of the participant's eligible contribution. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to $9.3 million, $8.9 million, and $8.3 million for fiscal years 2009, 2008 and 2007. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for fiscal years 2009, 2008 or 2007. At September 30, 2009 and 2008, the Retirement Savings Plan held 3.8 percent and 3.4 percent of our outstanding common stock.

The AEM 401K Profit-Sharing Plan covers substantially all AEM employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. The Company may elect to make safe harbor contributions up to three percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEM 401K Profit-Sharing Plan. Participants become fully vested in the discretionary profit-sharing contributions after three years of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. Discretionary contributions to the AEM 401K Profit-Sharing Plan are expensed as incurred and amounted to $0.7 million, $0.5 million and $0.8 million for fiscal years 2009, 2008 and 2007.

9. Details of Selected Consolidated Balance Sheet Captions

The following tables provide additional information regarding the composition of certain of our balance sheet captions.

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2009 and 2008:

	September 30	
	2009	2008
	(In thousands)	
Billed accounts receivable	$179,667	$411,225
Unbilled revenue	42,618	49,496
Other accounts receivable	21,999	31,731
Total accounts receivable	244,284	492,452
Less: allowance for doubtful accounts	(11,478)	(15,301)
Net accounts receivable	$232,806	$477,151

Other current assets

Other current assets as of September 30, 2009 and 2008 were comprised of the following accounts.

	September 30	
	2009	2008
	(In thousands)	
Assets from risk management activities	$ 31,643	$ 68,291
Deferred gas costs	22,233	55,103
Taxes receivable	15,115	22,052
Prepaid expenses	21,807	16,738
Current portion of leased assets receivable	2,973	2,973
Materials and supplies	3,349	4,304
Asset held for sale	19,925	—
Other	15,158	15,158
Total	$132,203	$184,619

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 fiscal year ended September 30, 2009, management approved a plan to pursue the sale of the storage facility project, which is expected to be completed within the next fiscal year. Accordingly, the assets associated with this project have been classified as an asset held for sale as of September 30, 2009.

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2009 and 2008:

	September 30	
	2009	2008
	(In thousands)	
Production plant	$ 23,359	$ 21,958
Storage plant	156,466	150,984
Transmission plant	1,029,487	942,169
Distribution plant	4,103,531	3,870,606
General plant	614,324	597,460
Intangible plant	54,253	66,919
	5,981,420	5,650,096
Construction in progress	105,198	80,060
	6,086,618	5,730,156
Less: accumulated depreciation and amortization	(1,647,515)	(1,593,297)
Net property, plant and equipment	$ 4,439,103	$ 4,136,859

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2009 and 2008 were comprised of the following accounts.

	September 30	
	2009	2008
	(In thousands)	
Pension plan assets in excess of plan obligations	$ —	$ 7,997
Marketable securities	41,699	37,940
Regulatory assets	227,925	130,785
Deferred financing costs	40,854	35,378
Assets from risk management activities	14,035	5,473
Other	11,146	8,077
Total	$335,659	$225,650

Other current liabilities

Other current liabilities as of September 30, 2009 and 2008 were comprised of the following accounts.

	September 30	
	2009	2008
	(In thousands)	
Customer deposits	$ 69,966	$ 75,297
Accrued employee costs	40,582	42,956
Deferred gas costs	110,754	76,979
Accrued interest	46,495	52,366
Liabilities from risk management activities	21,482	58,914
Taxes payable	49,821	53,639
Pension and postretirement obligations	28,712	16,950
Regulatory cost of removal accrual	14,342	18,628
Current deferred tax liability	9,054	1,833
Other	66,111	62,810
Total	$457,319	$460,372

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2009 and 2008 were comprised of the following accounts.

	September 30	
	2009	2008
	(In thousands)	
Postretirement obligations	$154,784	$137,075
Retirement plan obligations	160,236	88,143
Customer advances for construction	16,907	17,814
Regulatory liabilities	7,960	5,639
Asset retirement obligation	13,037	5,883
Uncertain tax positions	6,731	6,731
Liabilities from risk management activities	—	5,369
Other	8,503	727
Total	$368,158	$267,381

10. Earnings Per Share

Basic and diluted earnings per share for the fiscal years ended September 30 are calculated as follows:

	2009	2008	2007
	(In thousands, except per share data)		
Net income	$190,978	$180,331	$168,492
Denominator for basic income per share — weighted average common shares	91,117	89,385	86,975
Effect of dilutive securities:			
Restricted and other shares	858	790	620
Stock options	49	97	150
Denominator for diluted income per share — weighted average common shares	92,024	90,272	87,745
Net income per share — basic	$ 2.10	$ 2.02	$ 1.94
Net income per share — diluted	$ 2.08	$ 2.00	$ 1.92

There were approximately 70,000 out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal year ended September 30, 2009. There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal year ended September 30, 2008 and 2007.

11. Income Taxes

The components of income tax expense from continuing operations for 2009, 2008 and 2007 were as follows:

	2009	2008	2007
		(In thousands)	
Current			
Federal	$ (37,042)	$ 7,161	$22,616
State	7,964	7,696	9,810
Deferred			
Federal	138,959	85,573	56,349
State	(9,200)	12,367	5,772
Investment tax credits	(390)	(424)	(455)
	$100,291	$112,373	$94,092

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2009, 2008 and 2007 are set forth below:

	2009	2008	2007
		(In thousands)	
Tax at statutory rate of 35%	$101,944	$102,446	$91,904
Common stock dividends deductible for tax reporting	(1,591)	(1,363)	(1,233)
Depreciation/amortization	—	—	(4,727)
Tax exempt income	(153)	—	(1,890)
State taxes (net of federal benefit)	(803)	12,523	10,253
Other, net	894	(1,233)	(215)
Income tax expense	$100,291	$112,373	$94,092

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2009 and 2008 are presented below:

	2009	2008
	(In thousands)	
Deferred tax assets:		
Costs expensed for book purposes and capitalized for tax purposes	$ 6,771	$ 16,305
Accruals not currently deductible for tax purposes	7,664	11,627
Customer advances	6,256	6,769
Nonqualified benefit plans	41,359	39,632
Postretirement benefits	53,074	46,319
Treasury lock agreement	4,404	6,806
Unamortized investment tax credit	192	345
Regulatory liabilities	834	911
Tax net operating loss and credit carryforwards	1,997	616
Other, net	6,311	543
Total deferred tax assets	128,862	129,873
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(672,763)	(534,607)
Pension funding	(21,379)	(25,777)
Gas cost adjustments	(2,459)	(5,362)
Regulatory assets	(195)	(568)
Difference between book and tax on mark to market accounting	(12,060)	(6,694)
Total deferred tax liabilities	(708,856)	(573,008)
Net deferred tax liabilities	$(579,994)	$(443,135)
Deferred credits for rate regulated entities	$ 2,253	$ 2,397

We have tax carryforwards relating to state net operating losses amounting to $1.9 million. Depending on the jurisdiction in which the net operating loss was generated, the state net operating losses will begin to expire between 2014 and 2027.

As of September 30, 2009 and 2008, we had recorded liabilities associated with uncertain tax positions totaling $6.7 million. The realization of all of these tax benefits would reduce our income tax expense by approximately $6.7 million. There were no changes in unrecognized tax benefits as a result of tax positions taken during the current or prior years or as a result of settlements with taxing authorities for the year ended September 30, 2009.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2004.

12. Commitments and Contingencies

Litigation

Colorado-Kansas Division

We are a defendant in a lawsuit originally filed by Quinque Operating Company, Tom Boles and Robert Ditto in September 1999 in the District Court of Stevens County, Kansas against more than 200 companies in the natural gas industry. The plaintiffs, who purport to represent a class of royalty owners, allege that the defendants have underpaid royalties on gas taken from wells situated on non-federal and non-Indian lands in Kansas, predicated upon allegations that the defendants' gas measurements were inaccurate. The plaintiffs have not specifically alleged an amount of damages. We are also a defendant, along with over 50 other companies in the natural gas industry, in another proposed class action lawsuit filed in the same court by Will Price, Tom Boles and The Cooper Clarke Foundation in May 2003 involving similar allegations. In September 2009, the court ruled that the plaintiffs in both cases had not provided sufficient evidence to meet the standards of a class action and denied class action status to each of the plaintiffs in both cases. We believe that the plaintiffs' claims in both cases are lacking in merit and we intend to vigorously defend these actions. While the results cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse effect on our financial condition, results of operations or cash flows. We are also a defendant in another lawsuit entitled *In Re Natural Gas Royalties Qui Tam Litigation*, involving similar allegations filed in June 1997 in the United States District Court for the District of Colorado, which was later transferred to the United States District Court for the District of Wyoming, where it was consolidated with approximately 50 additional lawsuits in October 1999. In October 2006, the District Court granted the defendants' motion to dismiss this lawsuit for lack of subject matter jurisdiction. The plaintiffs appealed this dismissal order on which oral arguments were heard by the United States Court of Appeals for the Tenth Circuit in September 2008. In May 2009, the Tenth Circuit denied such appeal and motion for rehearing. In August 2009, the plaintiffs filed for a Writ of Certiorari with the Supreme Court of the United States appealing the Tenth Circuit's order dismissing the lawsuit, which the Supreme Court denied on October 5, 2009.

We are a party to other litigation and claims that have arisen in the ordinary course of our business. While the results of such litigation and claims cannot be predicted with certainty, we believe the final outcome of such litigation and claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Environmental Matters

Former Manufactured Gas Plant Sites

We are the owner or previous owner of former manufactured gas plant sites in Johnson City and Bristol, Tennessee, Keokuk, Iowa, Hannibal, Missouri and Owensboro, Kentucky, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. Under current environmental protection laws and regulations, we may be responsible for response actions with respect to such materials if response actions are necessary. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa, Missouri, Kentucky and the United States Environmental Protection Agency.

We are a party to other environmental matters and claims that have arisen in the ordinary course of our business. While the ultimate results of response actions to these environmental matters and claims cannot be predicted with certainty, we believe the final outcome of such response actions will not have a material adverse effect on our financial condition, results of operations or cash flows because we believe that the expenditures related to such response actions will either be recovered through rates, shared with other parties or are adequately covered by insurance.

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 September 30, 2009, AEM was committed to purchase 72.6 Bcf within one year, 19.4 Bcf within one to three years and 2.2 Bcf after three years under indexed contracts. AEM is committed to purchase 2.9 Bcf within one year under fixed price contracts with prices ranging from $2.95 to $7.68 per Mcf. Purchases under these contracts totaled $1,484.5 million, $3,075.0 million and $2,065.1 million for 2009, 2008 and 2007.

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 September 30, 2009 are as follows (in thousands):

2010	$312,837
2011	7,600
2012	7,632
2013	7,974
2014	2,703
	$338,746

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 as of September 30, 2009 are as follows (in thousands):

	Natural Gas Marketing	Pipeline, Storage and Other
2010	$20,510	$1,775
2011	15,994	500
2012	13,323	500
2013	8,556	500
2014	4,842	500
Thereafter	3,157	250
	$66,382	$4,025

Other Contingencies

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. We have responded timely to data requests received from the Commission and are fully cooperating with the Commission during this investigation.

The Commission agreed to allow the Company to conduct our own internal investigation into compliance with the Commission's rules. We have completed the investigation and have provided a report on the results of the investigation to the Commission, which report is currently under review by the Commission. We currently are unable to predict the final outcome of this investigation or the potential impact it could have on our financial position, results of operations or cash flows.

In September 2008, the Texas Railroad Commission issued a final rule requiring the replacement of known compression couplings at pre-bent gas meter risers by November 2009. Compliance with this rule has not had a significant impact on our West Texas Division but has required us to spend significant amounts of capital in our Mid-Tex Division. As of September 30, 2009 we had substantially completed our pre-bent riser replacement program in the Mid-Tex Division.

13. Leases

Leasing Operations

A subsidiary of AEH has constructed electric peaking power-generating plants and associated facilities and entered into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In connection with these lease transactions, as of September 30, 2009 and 2008, we had receivables of $10.8 million and $13.8 million and recognized income of $1.2 million, $1.3 million and $1.5 million for fiscal years 2009, 2008 and 2007. The future minimum lease payments to be received for each of the five succeeding fiscal years are as follows:

	Minimum Lease Receipts
	(In thousands)
2010	$ 2,973
2011	2,973
2012	2,973
2013	1,897
2014	—
Thereafter	—
Total minimum lease receipts	$10,816

Capital and Operating Leases

We have entered into non-cancelable operating leases for office and warehouse space used in our operations. The remaining lease terms range from one to 22 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $1.3 million at both September 30, 2009 and 2008. Accumulated depreciation for these capital leases totaled $0.8 million and $0.7 million at September 30, 2009 and 2008. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2009 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2010	$ 186	$ 17,764
2011	186	16,402
2012	186	15,007
2013	186	13,873
2014	186	13,858
Thereafter	635	142,106
Total minimum lease payments	1,565	$219,010
Less amount representing interest	617	
Present value of net minimum lease payments	$ 948	

Consolidated lease and rental expense amounted to $13.6 million, $14.2 million and $11.3 million for fiscal 2009, 2008 and 2007.

14. Concentration of Credit Risk

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

Customer diversification also helps mitigate AEM's exposure to credit risk. AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements, primarily consisting of letters of credit, and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2009, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers, including affiliate customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2009 and 2008.

	September 30, 2009	September 30, 2008
Investment grade	53%	52%
Non-investment grade	47%	48%
Total	100%	100%

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2009. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Natural Gas Distribution Segment[1]	Natural Gas Marketing Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$20,523	$20,523
Non-investment grade counterparties	—	7,476	7,476
	$—	$27,999	$27,999

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

15. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for fiscal 2009, 2008 and 2007 are presented below.

	2009	2008	2007
		(In thousands)	
Cash paid for interest	$163,554	$139,958	$151,616
Cash paid (received) for income taxes	$ (36,405)	$ 3,483	$ 8,939

There were no significant noncash investing and financing transactions during fiscal 2009, 2008 and 2007. All cash flows and noncash activities related to our commodity financial instruments are considered as operating activities.

16. Segment Information

Atmos Energy Corporation and its 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 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.

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. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

Summarized income statements and capital expenditures by segment are shown in the following tables.

	Year Ended September 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	$2,983,966	$119,427	$1,832,912	$32,775	$ —	$4,969,080
Intersegment revenues	799	90,231	503,935	9,149	(604,114)	—
	2,984,765	209,658	2,336,847	41,924	(604,114)	4,969,080
Purchased gas cost	1,960,137	—	2,252,235	12,428	(602,422)	3,622,378
Gross profit	1,024,628	209,658	84,612	29,496	(1,692)	1,346,702
Operating expenses						
Operation and maintenance	369,429	85,249	34,201	7,167	(2,036)	494,010
Depreciation and amortization	192,274	20,413	1,590	2,931	—	217,208
Taxes, other than income	169,312	10,231	2,271	886	—	182,700
Asset impairments	4,599	602	146	35	—	5,382
Total operating expenses	735,614	116,495	38,208	11,019	(2,036)	899,300
Operating income	289,014	93,163	46,404	18,477	344	447,402
Miscellaneous income (expense)	5,766	1,433	537	6,253	(17,292)	(3,303)
Interest charges	124,055	30,982	12,911	1,830	(16,948)	152,830
Income before income taxes	170,725	63,614	34,030	22,900	—	291,269
Income tax expense	53,918	22,558	13,836	9,979	—	100,291
Net income	$ 116,807	$ 41,056	$ 20,194	$12,921	$ —	$ 190,978
Capital expenditures	$ 379,500	$108,332	$ 242	$21,420	$ —	$ 509,494

	Year Ended September 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	$3,654,338	$108,116	$3,436,563	$22,288	$ —	$7,221,305
Intersegment revenues	792	87,801	851,299	9,421	(949,313)	—
	3,655,130	195,917	4,287,862	31,709	(949,313)	7,221,305
Purchased gas cost	2,649,064	—	4,194,841	3,396	(947,322)	5,899,979
Gross profit	1,006,066	195,917	93,021	28,313	(1,991)	1,321,326
Operating expenses						
Operation and maintenance	389,244	77,439	30,903	4,983	(2,335)	500,234
Depreciation and amortization	177,205	19,899	1,546	1,792	—	200,442
Taxes, other than income	178,452	8,834	4,180	1,289	—	192,755
Total operating expenses	744,901	106,172	36,629	8,064	(2,335)	893,431
Operating income	261,165	89,745	56,392	20,249	344	427,895
Miscellaneous income	9,689	1,354	2,022	8,428	(18,762)	2,731
Interest charges	117,933	27,049	9,036	2,322	(18,418)	137,922
Income before income taxes	152,921	64,050	49,378	26,355	—	292,704
Income tax expense	60,273	22,625	19,389	10,086	—	112,373
Net income	$ 92,648	$ 41,425	$ 29,989	$16,269	$ —	$ 180,331
Capital expenditures	$ 386,542	$ 75,071	$ 340	$10,320	$ —	$ 472,273

	Year Ended September 30, 2007					
	Natural Gas Distribution	Regulated Transmission and Storage	Natural Gas Marketing	Pipeline, Storage and Other	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$3,358,147	$ 84,344	$2,432,280	$23,660	$ —	$5,898,431
Intersegment revenues	618	78,885	719,050	9,740	(808,293)	—
	3,358,765	163,229	3,151,330	33,400	(808,293)	5,898,431
Purchased gas cost	2,406,081	—	3,047,019	792	(805,543)	4,648,349
Gross profit	952,684	163,229	104,311	32,608	(2,750)	1,250,082
Operating expenses						
Operation and maintenance	379,175	56,231	26,480	4,581	(3,094)	463,373
Depreciation and amortization	177,188	18,565	1,536	1,574	—	198,863
Taxes, other than income	171,845	8,603	1,255	1,163	—	182,866
Asset impairments	3,289	—	—	3,055	—	6,344
Total operating expenses	731,497	83,399	29,271	10,373	(3,094)	851,446
Operating income	221,187	79,830	75,040	22,235	344	398,636
Miscellaneous income	8,945	2,105	6,434	8,173	(16,473)	9,184
Interest charges	121,626	27,917	5,767	6,055	(16,129)	145,236
Income before income taxes	108,506	54,018	75,707	24,353	—	262,584
Income tax expense	35,223	19,428	29,938	9,503	—	94,092
Net income	$ 73,283	$ 34,590	$ 45,769	$14,850	$ —	$ 168,492
Capital expenditures	$ 327,442	$ 59,276	$ 1,069	$ 4,648	$ —	$ 392,435

The following table summarizes our revenues by products and services for the fiscal year ended September 30.

	2009	2008	2007
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,830,140	$2,131,447	$1,982,801
Commercial	838,184	1,077,056	970,949
Industrial	135,633	212,531	195,060
Public authority and other	89,183	137,821	114,298
Total gas sales revenues	2,893,140	3,558,855	3,263,108
Transportation revenues	59,115	59,712	59,195
Other gas revenues	31,711	35,771	35,844
Total natural gas distribution revenues	2,983,966	3,654,338	3,358,147
Regulated transmission and storage revenues	119,427	108,116	84,344
Natural gas marketing revenues	1,832,912	3,436,563	2,432,280
Pipeline, storage and other revenues	32,775	22,288	23,660
Total operating revenues	$4,969,080	$7,221,305	$5,898,431

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

	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

	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

17. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2009:				
Operating revenues				
Natural gas distribution	$1,055,968	$1,230,420	$ 386,985	$ 311,392
Regulated transmission and storage	54,682	59,234	49,345	46,397
Natural gas marketing	787,495	708,658	453,504	387,190
Pipeline, storage and other	16,448	12,272	8,226	4,978
Intersegment eliminations	(198,261)	(189,178)	(117,285)	(99,390)
	1,716,332	1,821,406	780,775	650,567
Gross profit	395,212	460,051	259,640	231,799
Operating income	163,194	226,547	43,683	13,978
Net income (loss)	75,963	129,003	1,964	(15,952)
Net income (loss) per basic share	$ 0.84	$ 1.42	$ 0.02	$ (0.17)
Net income (loss) per diluted share	$ 0.83	$ 1.41	$ 0.02	$ (0.17)
Fiscal year 2008:				
Operating revenues				
Natural gas distribution	$ 928,177	$1,521,856	$ 676,639	$ 528,458
Regulated transmission and storage	45,046	51,440	46,286	53,145
Natural gas marketing	840,717	1,128,653	1,189,722	1,128,770
Pipeline, storage and other	6,727	10,022	3,880	11,080
Intersegment eliminations	(163,157)	(227,986)	(277,382)	(280,788)
	1,657,510	2,483,985	1,639,145	1,440,665
Gross profit	369,638	434,394	246,222	271,072
Operating income	158,509	211,143	20,709	37,534
Net income (loss)	73,803	111,534	(6,588)	1,582
Net income (loss) per basic share	$ 0.83	$ 1.25	$ (0.07)	$ 0.02
Net income (loss) per diluted share	$ 0.82	$ 1.24	$ (0.07)	$ 0.02

ITEM 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

None.

ITEM 9A. ***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 Rule 13a-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 September 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.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2009, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ ROBERT W. BEST	/s/ FRED E. MEISENHEIMER
Robert W. Best Chairman and Chief Executive Officer	Fred E. Meisenheimer Senior Vice President and Chief Financial Officer

November 16, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Atmos Energy Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of September 30, 2009 and 2008, and the related statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2009 of Atmos Energy Corporation and our report dated November 16, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 16, 2009

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth 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.

ITEM 9B. *Other Information.*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance.*

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 3, 2010. Information regarding executive officers is included in Part I of this Annual Report on Form 10-K.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 3, 2010.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Governance." In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance."

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 3, 2010.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 3, 2010. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 3, 2010.

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 3, 2010.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules.*

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements and financial statement schedule listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. *Exhibits*

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K. The exhibits numbered 10.5(a) through 10.12(g) are management contracts or compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

Date: November 16, 2009

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Robert W. Best and Fred. E. Meisenheimer, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ ROBERT W. BEST Robert W. Best	Chairman and Chief Executive Officer	November 16, 2009
/s/ KIM R. COCKLIN Kim R. Cocklin	President, Chief Operating Officer and Director	November 16, 2009
/s/ FRED E. MEISENHEIMER Fred E. Meisenheimer	Senior Vice President and Chief Financial Officer	November 16, 2009
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Vice President and Controller (Principal Accounting Officer)	November 16, 2009
/s/ TRAVIS W. BAIN, II Travis W. Bain, II	Director	November 16, 2009
/s/ RICHARD W. CARDIN Richard W. Cardin	Director	November 16, 2009
/s/ RICHARD W. DOUGLAS Richard W. Douglas	Director	November 16, 2009
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 16, 2009
/s/ THOMAS J. GARLAND Thomas J. Garland	Director	November 16, 2009
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 16, 2009
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 16, 2009
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 16, 2009
/s/ PHILLIP E. NICHOL Phillip E. Nichol	Director	November 16, 2009

/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 16, 2009
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 16, 2009
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 16, 2009
/s/ RICHARD WARE II Richard Ware II	Director	November 16, 2009

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2009

	Balance at Beginning of Period	Additions: Charged to Cost & Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
2009					
Allowance for doubtful accounts	$15,301	$ 7,769	$—	$11,592[1]	$11,478
2008					
Allowance for doubtful accounts	$16,160	$15,655	$—	$16,514[1]	$15,301
2007					
Allowance for doubtful accounts	$13,686	$19,718	$—	$17,244[1]	$16,160

(1) Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Articles of Incorporation and Bylaws	
3.1	Amended and Restated Articles of Incorporation of Atmos Energy Corporation (as of February 9, 2005)	Exhibit 3(I) to Form 10-Q dated March 31, 2005 (File No. 1-10042)
3.2	Amended and Restated Bylaws of Atmos Energy Corporation (as of May 2, 2007)	Exhibit 3.1 to Form 8-K dated May 2, 2007 (File No. 1-10042)
	Instruments Defining Rights of Security Holders	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit (4)(b) to Form 10-K for fiscal year ended September 30, 1988 (File No. 1-10042)
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6	Indenture dated as of March 23, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(a)	Debenture Certificate for the 6¾% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.7(b)	Global Security for the 7⅜% Senior Notes due 2011	Exhibit 99.2 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.7(c)	Global Security for the 5⅛% Senior Notes due 2013	Exhibit 10(2)(c) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(d)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(e)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(f)	Global Security for the 6.35% Senior Notes due 2017	Exhibit 4.2 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.7(g)	Global Security for the 8.50% Senior Notes due 2019	Exhibit 4.2 to Form 8-K dated March 26, 2009 (File No. 1-10042)
	Material Contracts	
10.1	Pipeline Construction and Operating Agreement, dated November 30, 2005, by and between Atmos-Pipeline Texas, a division of Atmos Energy Corporation, a Texas and Virginia corporation and Energy Transfer Fuel, LP, a Delaware limited partnership	Exhibit 10.1 to Form 8-K dated November 30, 2005 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.2	Revolving Credit Agreement (5 Year Facility), dated as of December 15, 2006, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, Wachovia Bank, N.A. as Syndication Agent and Bank of America, N.A., JPMorgan Chase Bank, N.A., and the Royal Bank of Scotland plc as Co-Documentation Agents, and the lenders from time to time parties thereto	Exhibit 10.1 to Form 8-K dated December 15, 2006 (File No. 1-10042)
10.3	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)
10.4(a)	Third Amended and Restated Credit Agreement, dated as of December 30, 2008, among Atmos Energy Marketing, LLC, BNP Paribas, Fortis Bank SA/NV, New York Branch, Societe Generale and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated December 30, 2008 (File No. 1-10042)
10.4(b)	First Amendment dated as of April 1, 2009, to the Third Amended and Restated Credit Agreement and the amended and restated Intercreditor Agreement	
10.4(c)	Intercreditor Agreement, dated as of March 31, 2008, among Fortis Capital Corp. and the other financial institutions which may become parties thereto	Exhibit 10.2 to Form 8-K dated March 31, 2008 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.5(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.5(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.5(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.5(b) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.6(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.6(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.7(a)*	Description of Financial and Estate Planning Program	Exhibit 10.25(b) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.7(b)*	Description of Sporting Events Program	Exhibit 10.26(c) to Form 10-K for fiscal year ended September 30, 1993 (File No. 1-10042)
10.8(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.8(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan, (An Amendment and Restatement of the Performance-Based Supplemental Executive Benefits Plan), Effective Date August 7, 2007	Exhibit 10.8(b) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.8(c)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.8(d)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.9(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.9(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.9(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)
10.10*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors	Exhibit 10.10 to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.11*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan (Amended and Restated as of November 12, 1997)	Exhibit 10.28 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.12(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 9, 2007)	Exhibit 10.2 to Form 10-Q for quarter ended March 31, 2007 (File No. 1-10042)
10.12(b)*	Amendment No. 1 to Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 9, 2007)	Exhibit 10.12(b) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.12(c)*	Form of Non-Qualified Stock Option Agreement under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(b) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.12(d)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.12(d) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.12(e)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.1 to Form 10-Q for quarter ended June 30, 2009 (File No. 1-10042)
10.12(f)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.2 to Form 10-Q for quarter ended June 30, 2009 (File No. 1-10042)
10.12(g)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated August 8, 2007)	Exhibit 10.12(f) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
12	Statement of computation of ratio of earnings to fixed charges	
	Other Exhibits, as indicated	
21	Subsidiaries of the registrant	
23.1	Consent of independent registered public accounting firm, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2009
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	

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

** These certifications 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 Annual Report on Form 10-K, will not be deemed to be filed with the Securities and Exchange 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.