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, 2012

OR

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

For the transition period from to

Commission file number 1-10042

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

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

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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.45) 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 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 ☐ (Do not check if a smaller reporting company) 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, 2012, was $2,764,486,845.

As of November 6, 2012, the registrant had 90,240,464 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 13, 2013, are incorporated by reference into Part III of this report.

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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
ERISA	Employee Retirement Income Security Act of 1974
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
Mid-Tex Cities	Represents 440 of the 441 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.
MMcf	Million cubic feet
Moody's	Moody's Investor Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
PAP	Pension Account Plan
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
SRF	Stable Rate Filing
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, and incorporated in Texas and Virginia, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. We deliver natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in nine 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.

In August 2012, we completed the sale of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers and announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers. After the closing of the Georgia transaction, we will operate in eight states.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers principally 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 safely operating our regulated and nonregulated businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

We have delivered excellent shareholder value by growing our earnings and increasing our dividends for over 25 consecutive years. Through fiscal 2005, 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. Since that time, we have 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.

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 three segments:

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

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

Our natural gas distribution segment represents approximately 65 percent of our consolidated net income. This segment is comprised of the following six regulated divisions, presented in order of total rate base, covering service areas in nine 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 and Virginia. See Note 6 in the consolidated financial statements for a description of the completed sale of our Missouri, Illinois and Iowa service areas and the anticipated sale of our Georgia distribution operations. 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 adjustment 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 approximately 97 percent of residential and commercial margins 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 the effect of lower gas usage when weather is warmer than normal and decrease customers' bills to offset the effect of higher gas usage when weather is colder than normal.

As of September 30, 2012 we had WNA for our residential and commercial meters in the following service areas for the following periods:

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

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.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically 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 reasonable cost. Major suppliers during fiscal 2012 were Anadarko Energy Services, BP Energy Company, ConocoPhillips, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., Iberdrola Renewables, Inc., National Fuel Marketing Company, LLC, Sequent Energy Management, L.P., Texla Energy Management, Inc. 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 4.4 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2012 was on February 11, 2012, when sales to customers reached approximately 3.0 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 43 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 primarily by our Atmos Pipeline — Texas Division.

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.

Below, we briefly describe 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, 2012, we held 1,006 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. In fiscal 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers that allowed us to update rates for customers in these cities using an annual rate review mechanism (RRM) from fiscal 2008 through fiscal 2011, when the RRM was active. We filed a formal rate case for the Mid-Tex Division in fiscal 2012. After the conclusion of this rate case, we expect to negotiate a new rate review mechanism process. In June 2011, we reached an agreement with the City of Dallas to enter into the Dallas Annual Rate Review (DARR). This rate review provides for an annual rate review without the necessity of filing a general rate case. The first rates were implemented under the DARR in June 2012.

Atmos Energy Kentucky/Mid-States Division. Our Kentucky/Mid-States Division currently operates in more than 230 communities across Georgia, Kentucky, 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.

On August 1, 2012, we completed the divestiture of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers in 189 communities, with some of the Missouri communities located in our Atmos Energy Colorado-Kansas Division. On August 8, 2012, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers in 19 communities. See Note 6 in the consolidated financial statements for further information regarding these divestitures.

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 nonregulated 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. In fiscal 2008 and 2009, we reached an agreement with the West Texas service areas and the Amarillo and Lubbock service areas that allowed us to update rates for customers in these cities using an annual rate review mechanism (RRM) through fiscal 2011, when the RRM was active. We filed a formal rate case for the West Texas Division in fiscal 2012, which was approved on October 2, 2012. We expect to negotiate a new rate review mechanism process in fiscal 2013.

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, 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 and in Kansas through periodic infrastructure replacement 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	05/01/2011	$807,733	9.36%	11.80%
Atmos Pipeline — Texas — GRIP	Texas	04/10/2012	879,752	9.36%	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	10.25%
	Kansas	09/01/2012	160,075	(2)	(2)
Kentucky/Mid-States	Georgia	02/02/2012	96,338[3]	8.61%	10.50% - 10.90%
	Kentucky	06/01/2010	208,702[4]	(2)	(2)
	Tennessee	04/01/2009	190,100	8.24%	10.30%
	Virginia	11/23/2009	36,861	8.48%	9.50% - 10.50%
Louisiana	Trans LA	04/01/2012	100,575	8.24%	10.00% - 10.80%
	LGS	07/01/2012	284,607	8.27%	10.40%
Mid-Tex Cities	Texas	09/01/2011	1,389,187[5]	8.29%	9.70%
Mid-Tex — Dallas	Texas	06/01/2012	1,472,583[5]	8.50%	10.10%
Mid-Tex — Environs GRIP	Texas	06/26/2012	1,449,544[5]	8.60%	10.40%
Mississippi	Mississippi	01/11/2012	274,576	8.06%	9.75%
West Texas	Amarillo[6]	08/01/2011	(2)	(2)	9.60%
	Lubbock[6]	09/09/2011	60,892	8.19%	9.60%
	West Texas[6]	08/01/2011	146,039	8.19%	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider[7]	WNA	Performance-Based Rate Program[8]	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	50/50	Yes[9]	No	No	111,354
	Kansas	(2)	Yes	Yes	No	129,468
Kentucky/Mid-States	Georgia	50/50	No	Yes	Yes	63,707
	Kentucky	(2)	Yes	Yes	Yes	170,608
	Tennessee	52/48	Yes	Yes	Yes	134,927
	Virginia	51/49	Yes	Yes	No	23,335
Louisiana	Trans LA	52/48	No	Yes	No	75,607
	LGS	52/48	No	Yes	No	277,159
Mid-Tex Cities	Texas	50/50	Yes	Yes	No	1,252,548
Mid-Tex — Dallas	Texas	48/52	Yes	Yes	No	250,510
Mid-Tex — Environs	Texas	51/49	Yes	Yes	No	62,627
Mississippi	Mississippi	50/50	No	Yes	No	263,302
West Texas	Amarillo[6]	52/48	Yes	Yes	No	70,258
	Lubbock[6]	52/48	Yes	Yes	No	74,244
	West Texas[6]	52/48	Yes	Yes	No	156,935

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the most recent 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) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $36.1 million included in the October 2011 Pipeline Replacement Program (PRP) surcharge. A total of $36.1 million of the Georgia

rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.68 percent and an authorized return on equity of 10.70 percent.

(4) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $24.0 million included in the October 2011 PRP surcharge. A total of $24.0 million of the Kentucky rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.74 percent and an authorized return on equity of 10.50 percent.

(5) The Mid-Tex Rate Base amounts for the Mid-Tex Cities and Dallas & Environs areas represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base.

(6) On October 2, 2012, a rate case settlement was approved by the Texas Railroad Commission that combined the former Amarillo, Lubbock and West Texas jurisdictions into a single "West Texas" jurisdiction.

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

(8) 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.

(9) The recovery of the gas portion of uncollectible accounts gas cost adjustment has been approved for a two-year pilot program.

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment represents approximately 30 percent of our consolidated net income and 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 and lending arrangements 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. Rates are 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 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 with our pipeline system providing access to all of these basins.

Nonregulated Segment Overview

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States. Currently, this segment represents less than five percent of our consolidated net income.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. The majority of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions.

Ratemaking Activity

Overview

The method of determining regulated rates varies among the states in which our regulated businesses 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 rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has:

- Annual ratemaking mechanisms in place in four states that provide for an annual rate review and adjustment to rates for approximately 77 percent of our natural gas distribution gross margin.
- Accelerated recovery of capital for approximately 74 percent of our natural gas distribution gross margin.
- WNA mechanisms in eight states that serve to minimize the effects of weather on approximately 97 percent of our natural gas distribution gross margin.
- The ability to recover the gas cost portion of bad debts for approximately 75 percent of our natural gas distribution gross margin.

Although substantial progress has been made in recent years by improving rate design across Atmos Energy's operating areas, we will continue to seek improvements in rate design to address cost variations that are related to pass-through energy costs beyond our control. Further, 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 regulated revenues in the fiscal years ended September 30, 2012, 2011 and 2010 were derived from sales at rates set by or subject to approval by local or state authorities. Net operating income increases resulting from ratemaking activity totaling $30.7 million, $72.4 million and $56.8 million, became effective in fiscal 2012, 2011 and 2010, as summarized below:

	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
Rate Action	2012	2011	2010
		(In thousands)	
Rate case filings	$ 4,309	$20,502	$23,663
Infrastructure programs	19,172	15,033	18,989
Annual rate filing mechanisms	7,044	35,216	13,757
Other ratemaking activity	167	1,675	392
	$30,692	$72,426	$56,801

Additionally, the following ratemaking efforts were initiated during fiscal 2012 but had not been completed as of September 30, 2012:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	PRP[1]	Georgia	$ 1,079
	PRP[1]	Kentucky	2,425
	PRP[1]	Virginia	101
	Rate Case[2]	Tennessee	11,230
	GRAM[3]	Georgia	1,079
Mississippi	Stable Rate Filing	Mississippi	4,830
Mid-Tex	Rate Case[4]	Railroad Commission of Texas (RRC)	46,537
West Texas	Rate Case[5]	RRC	9,427
			$76,708

[1] The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure. The Georgia, Kentucky and Virginia PRPs were implemented on October 1, 2012.

[2] A settlement was approved on November 7, 2012 for an operating income increase of $7.5 million.

[3] Georgia Rate Adjustment Mechanism

[4] A hearing was conducted in September 2012. A final order is expected in December 2012.

[5] On October 2, 2012, the RRC approved a $6.6 million operating income increase.

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 safely deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2012 Rate Case Filings:			
Colorado-Kansas	Kansas	$ 3,764	09/01/2012
West Texas — Environs	Texas	545	11/08/2011
Total 2012 Rate Case Filings		$ 4,309	
2011 Rate Case Filings:			
West Texas — Amarillo Environs	Texas	$ 78	07/26/2011
Atmos Pipeline — Texas	Texas	20,424	05/01/2011
Total 2011 Rate Case Filings		$20,502	
2010 Rate Case Filings:			
Kentucky/Mid-States	Missouri	$ 3,977	09/01/2010
Colorado-Kansas	Kansas	3,855	08/01/2010
Kentucky/Mid-States	Kentucky	6,636	06/01/2010
Kentucky/Mid-States	Georgia	2,935	03/31/2010
Mid-Tex	Texas(1)	2,963	01/26/2010
Colorado-Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$23,663	

(1) In its final order, the RRC approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Operating income should increase $0.2 million, net of the GRIP 2008 rates that will be superseded. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

Infrastructure Programs

As discussed above in "Natural Gas Distribution Segment Overview" and "Regulated Transmission and Storage Segment Overview," infrastructure programs such as GRIP allow our regulated companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia and Kentucky. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2012, 2011 and 2010:

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2012 Infrastructure Programs:				
Mid-Tex Unincorporated (Environs)[1]	12/2011	$145,671	$ 744	06/26/2012
Atmos Pipeline — Texas	12/2011	87,210	14,684	04/10/2012
Kentucky/Mid-States — Georgia[2]	09/2010	7,160	1,215	10/01/2011
Kentucky/Mid-States — Kentucky[2]	09/2012	17,347	2,529	10/01/2011
Total 2012 Infrastructure Programs		$257,388	$19,172	
2011 Infrastructure Programs:				
Atmos Pipeline — Texas	12/2010	$ 72,980	$12,605	07/26/2011
Mid-Tex/Environs	12/2010	107,840	576	06/27/2011
West Texas/Lubbock & WT Cities Environs	12/2010	17,677	343	06/01/2011
Kentucky/Mid-States — Kentucky [2]	09/2011	3,329	468	06/01/2011
Kentucky/Mid-States — Missouri[3]	09/2010	2,367	277	02/14/2011
Kentucky/Mid-States — Georgia[2]	09/2009	5,359	764	10/01/2010
Total 2011 Infrastructure Programs		$209,552	$15,033	
2010 Infrastructure Programs:				
Mid-Tex[4]	12/2009	$ 16,957	$ 2,983	09/01/2010
West Texas	12/2009	19,158	363	06/14/2010
Atmos Pipeline — Texas	12/2009	95,504	13,405	04/20/2010
Kentucky/Mid-States — Missouri[3]	06/2009	3,578	563	03/02/2010
Colorado-Kansas — Kansas[5]	08/2009	6,917	766	12/12/2009
Kentucky/Mid-States — Georgia[2]	09/2008	6,327	909	10/01/2009
Total 2010 Infrastructure Programs		$148,441	$18,989	

(1) Incremental net utility plant investment represents the system-wide incremental investment for the Mid-Tex Division. The increase in annual operating income is for the unincorporated areas of the Mid-Tex Division only.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure.

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

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

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

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, Mississippi and Georgia divisions and in a portion of our Texas divisions. These mechanisms are referred to as Dallas annual rate review (DARR) in our Mid-Tex Division, stable rate filings in the Mississippi Division, the rate stabilization clause in the Louisiana Division, the Georgia Rate Adjustment Mechanism (GRAM) in the Georgia Division and previously as rate review mechanisms (RRM) in our Texas divisions. The following table summarizes filings made under our various annual rate filing mechanisms:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2012 Filings:				
Louisiana	LGS	12/31/2011	$ 2,324	07/01/2012
Mid-Tex	Dallas	09/30/2011	1,204	06/01/2012
Louisiana	Trans La	09/30/2011	11	04/01/2012
Kentucky/Mid-States	Georgia	09/30/2011	(818)	02/01/2012
Mississippi	Mississippi	06/30/2011	4,323	01/11/2012
Total 2012 Filings			$ 7,044	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2010	$ 5,126	09/27/2011
Mid-Tex	Dallas	12/31/2010	1,084	09/27/2011
West Texas	Lubbock	12/31/2010	319	09/08/2011
West Texas	Amarillo	12/31/2010	(492)	08/01/2011
Louisiana	LGS	12/31/2010	4,109	07/01/2011
Mid-Tex	Dallas	12/31/2010	1,598	07/01/2011
Louisiana	TransLa	09/30/2010	350	04/01/2011
Mid-Tex	Settled Cities	12/31/2009	23,122	10/01/2010
Total 2011 Filings			$35,216	
2010 Filings:				
West Texas	Lubbock	12/31/2009	$ (902)	09/01/2010
West Texas	WT Cities	12/31/2009	700	08/15/2010
West Texas	Amarillo	12/31/2009	1,200	08/01/2010
Louisiana	LGS	12/31/2009	3,854	07/01/2010
Louisiana	TransLa	09/30/2009	1,733	04/01/2010
Mississippi	Mississippi	06/30/2009	3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$13,757	

Beginning in fiscal year 2008, we entered into RRM mechanisms within our Mid-Tex and West Texas divisions. Throughout the period of fiscal 2008 through fiscal 2011, when the RRM mechanisms were active, we were able to successfully implement new base rates within the various cities of both divisions. In fiscal 2012, we filed a rate case in both the Mid-Tex Division (for all cities except Dallas) and the West Texas Division. Following the conclusion of the Mid-Tex Division case, we expect to negotiate a new rate review mechanism process with each of the cities within both the Mid-Tex and West Texas divisions.

We continue to operate under an annual rate mechanism, DARR, with the City of Dallas, which was approved in June 2011. The first rates were implemented under the DARR in June 2012.

During fiscal 2011, the RRC's Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expense associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2012, 2011 and 2010:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income	Effective Date
			(In thousands)	
2012 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$ 167	01/14/2012
Total 2012 Other Rate Activity			$ 167	
2011 Other Rate Activity:				
West Texas	Triangle	Special Contract	$ 641	07/01/2011
Colorado-Kansas	Kansas	Ad Valorem[1]	685	01/01/2011
Colorado-Kansas	Colorado	AMI[2]	349	12/01/2010
Total 2011 Other Rate Activity			$1,675	
2010 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$ 392	01/05/2010
Total 2010 Other Rate Activity			$ 392	

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates.

(2) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of our Colorado service area.

Other Regulation

Each of our natural gas distribution divisions as well as our regulated transmission and storage division 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 transmission and 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.

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 the necessary and appropriate steps to comply with these regulations.

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.

Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services. The increased competition has reduced margins most notably on its high-volume accounts.

Employees

At September 30, 2012, we had 4,759 employees, consisting of 4,646 employees in our regulated operations and 113 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 during fiscal 2012, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any violations 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:

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 few 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.

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 nonregulated segment because the commodity financial instrument markets could become unavailable to us. Our nonregulated segment depends primarily upon a committed 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 nonregulated 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 in the last few years, 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 improving current economic conditions, 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. Additionally, our industrial customers may seek alternative energy sources, which could result in lower sales volumes.

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. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of health care benefits for our employees. Further, the costs to the Company of providing such benefits and related funding requirements are subject to the continued and timely recovery of such costs through our rates.

We provide a cash-balance pension plan and postretirement healthcare benefits to eligible full-time employees. The costs of providing such benefits and related funding requirements could be influenced by changes in the market value of the assets funding our pension and postretirement healthcare plans. Any significant declines in the value of these investments could increase the costs of our pension and postretirement healthcare plans and related funding requirements in the future. Further, our costs of providing such benefits and related funding requirements are also subject to a number of factors, including (i) 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; and (ii) various actuarial calculations and assumptions, which may differ materially from actual results due primarily to changing market and economic conditions and higher or lower withdrawal rates.

In addition, the costs of providing health care benefits to our employees could significantly increase over the next five to ten years due primarily to the Health Care Reform Act of 2010. Although the full effects of the Act should not impact the Company until 2014, the future costs of compliance with its provisions are difficult to measure at this time. Also, the costs to the Company of providing such benefits and related funding requirements could also increase materially in the future, depending on the timing of the recovery, if any, of such costs through our rates.

Our risk management 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 caused by market supply and demand dynamics 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, particularly in our nonregulated business segment, which could lead to volatility in our earnings.

Physical trading in our nonregulated business segment 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. 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. 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. 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 before the open positions can be closed.

Further, the timing of the recognition for financial accounting purposes of gains or losses resulting from changes in the fair value of derivative financial instruments designated as hedges usually does not match 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. Also, if the local physical markets in which we trade do not move consistently with the NYMEX futures market upon which most of our commodity derivative financial instruments are valued, we could experience increased volatility in the financial results of our nonregulated segment.

Our nonregulated segment manages margins and limits 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. Any significant 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 compared to historical norms for both short and long-term 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 they 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 rapid changes in the capital markets.

We may experience increased federal, state and local regulation of the safety of our operations.

We are committed to constantly monitoring and maintaining our pipeline and distribution system to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 73,000 miles of pipeline and distribution lines. The pipeline replacement programs currently underway in several of our divisions typify the preventive maintenance and continual renewal that we perform on our natural gas distribution system in the nine states in which we currently operate. The safety and protection of the public, our customers and our employees is our top priority. However, due primarily to the unfortunate pipeline incident in California in 2010, we anticipate companies in the natural gas distribution business may be subjected to even greater federal, state and local oversight of the safety of their operations in the future. Although we believe these costs should be ultimately recoverable through our rates, costs of complying with such increased regulations may have at least a short-term adverse impact on our operating costs and financial results.

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

FERC has regulatory authority over 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. 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 have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The adoption of this type of 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 in the future 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 that may be adopted 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.

We have weather-normalized rates for over 95 percent of our residential and commercial meters, which substantially mitigates 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 nonregulated 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. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our natural gas distribution and regulated transmission and storage operations.

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 serve any growth in the number of our customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. In addition, although we should ultimately recover the cost of the expenditures through rates, we must make significant capital expenditures to comply with the recent rule issued by the RRC's Division of Public Safety that requires natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. 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 operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services.

Cyber-attacks or acts of cyber-terrorism could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information.

Our business operations and information technology systems may be vulnerable to an attack by individuals or organizations intending to disrupt our business operations and information technology systems. We use such systems to manage our natural gas distribution and intrastate pipeline operations and other business processes. Disruption of those systems could adversely impact our ability to safely deliver natural gas to our customers, operate our pipeline systems or serve our customers timely. Accordingly, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected. In addition, we use our information technology systems to protect confidential or sensitive customer, employee and Company information developed and maintained in the normal course of our business. Any attack on such systems that would result in the unauthorized release of customer, employee or other confidential or sensitive data could have a material adverse effect on our business reputation, increase our costs and expose us to additional material legal claims and liability. As a result, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected.

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

Our natural gas distribution and pipeline and storage businesses involve 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 maintain liability and property insurance coverage in place for many of these hazards and risks. However, because some of 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, 2012, our natural gas distribution segment owned an aggregate of 68,072 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 5,698 miles of gas transmission and gathering lines and our non-regulated segment owned 105 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 at September 30, 2012:

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	105,100
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	228,100
Regulated Transmission and Storage Segment — Texas	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated 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	60,458,299	30,549,198	91,007,497	1,590,100

(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 at September 30, 2012:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Natural Gas Distribution Segment			
	Colorado-Kansas Division	4,248,409	108,089
	Kentucky/Mid-States Division	16,424,150	440,277
	Louisiana Division	2,636,539	161,393
	Mid-Tex Division	500,000	50,000
	Mississippi Division	3,875,429	165,402
	West Texas Division	3,375,000	106,000
Total		31,059,527	1,031,161
Nonregulated Segment			
	Atmos Energy Marketing, LLC	8,026,869	250,937
	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total		9,700,869	318,444
Total Contracted Storage Capacity		40,760,396	1,349,605

(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.

Offices

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

ITEM 3. *Legal Proceedings.*

See Note 13 to the consolidated financial statements.

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 2012 and 2011 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:

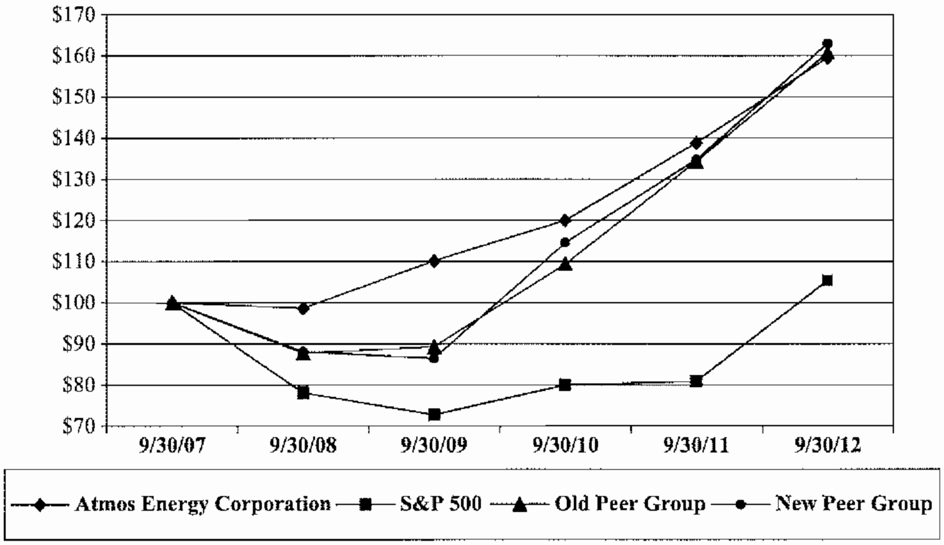
	Fiscal 2012			Fiscal 2011		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$35.40	$30.97	$.345	$31.72	$29.10	$.340
March 31	33.15	30.60	.345	34.98	31.51	.340
June 30	35.07	30.91	.345	34.94	31.34	.340
September 30	36.94	34.94	.345	34.32	28.87	.340
			$1.38			$1.36

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, 2012 was 17,883. 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 2012 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 Questar and excludes EQT Corporation because the Board of Directors determined that Questar 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, 2007 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					
	9/30/07	9/30/08	9/30/09	9/30/10	9/30/11	9/30/12
Atmos Energy Corporation	100.00	98.61	110.13	119.94	138.80	159.56
S&P 500	100.00	78.02	72.63	80.01	80.93	105.37
Old Peer Group	100.00	87.71	89.32	109.42	134.24	160.67
New Peer Group	100.00	88.10	86.44	114.56	134.80	162.92

The New Comparison Company Index contains a hybrid group of utility companies, primarily natural gas distribution companies, recommended by our independent compensation 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, Integrys Energy Group, Inc., National Fuel Gas, NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Questar Corporation, Vectren Corporation and WGL Holdings, Inc. The Old Comparison Company Index includes the companies listed above in the New Company Index with the exception of Questar Corporation, which replaced EQT 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, 2012.

	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	10,094	$24.95	1,949,088
Total equity compensation plans approved by security holders	10,094	24.95	1,949,088
Equity compensation plans not approved by security holders	—	—	—
Total	10,094	$24.95	1,949,088

On September 28, 2011, the Board of Directors approved a program authorizing the repurchase of up to five million shares of common stock over a five-year period. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the Company. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the Company deems appropriate. We did not repurchase any shares during the fourth quarter of fiscal 2012. At September 30, 2012, there were 4,612,009 shares of repurchase authority remaining under the program.

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				
	2012[1]	2011[1]	2010	2009[1]	2008
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$3,438,483	$4,286,435	$4,661,060	$4,793,248	$7,039,342
Gross profit	$1,323,739	$1,300,820	$1,314,136	$1,297,682	$1,275,077
Income from continuing operations	$ 192,196	$ 189,588	$ 189,851	$ 175,026	$ 166,696
Net income	$ 216,717	$ 207,601	$ 205,839	$ 190,978	$ 180,331
Diluted income per share from continuing operations	$ 2.10	$ 2.07	$ 2.03	$ 1.90	$ 1.84
Diluted net income per share	$ 2.37	$ 2.27	$ 2.20	$ 2.07	$ 1.99
Cash dividends declared per share	$ 1.38	$ 1.36	$ 1.34	$ 1.32	$ 1.30
Financial Condition					
Net property, plant and equipment[2]	$5,475,604	$5,147,918	$4,793,075	$4,439,103	$4,136,859
Total assets	$7,495,675	$7,282,871	$6,763,791	$6,367,083	$6,386,699
Capitalization:					
Shareholders' equity	$2,359,243	$2,255,421	$2,178,348	$2,176,761	$2,052,492
Long-term debt (excluding current maturities)	1,956,305	2,206,117	1,809,551	2,169,400	2,119,792
Total capitalization	$4,315,548	$4,461,538	$3,987,899	$4,346,161	$4,172,284

(1) Financial results for fiscal years 2012, 2011 and 2009 include a $5.3 million, $30.3 million and a $5.4 million pre-tax loss for the impairment of certain assets.

(2) Amounts shown for fiscal 2012 and 2011 are net of assets held for sale.

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 adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

CRITICAL ACCOUNTING POLICIES

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 base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from estimates.

Our significant accounting policies are discussed in Note 2 to our consolidated financial statements. The accounting policies discussed below are both important to the presentation of our financial condition and results of operations and require management to make difficult, subjective or complex accounting estimates. Accordingly, these critical accounting policies are reviewed periodically by the Audit Committee of the Board of Directors.

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.

Unbilled Revenue — 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.

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives for using financial instruments have been tailored to meet the needs of our regulated and nonregulated businesses. These objectives are more fully described in Note 4 to the consolidated financial statements.

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. Market value changes result in a change in the fair value of these financial instruments. The recognition of the changes in fair value of these financial instruments are recorded in the income statement is contingent upon 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.

We have elected to treat forward gas supply contracts used in our regulated operations to deliver gas as normal purchases and normal sales. Financial instruments used to manage commodity price risk in our natural gas distribution segment do not impact this segment's results of operations as the realized gains and losses are ultimately recovered from ratepayers through our rates.

Our nonregulated segment also utilizes financial instruments to manage commodity price risk. We have designated the natural gas inventory held by this operating segment as the hedged item in a fair-value hedge. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges. Changes in the fair value of the inventory and designated hedges are recognized in purchased gas cost in the period of change.

Additionally, we have elected to treat fixed-price forward contracts used in our nonregulated segment to deliver gas as normal purchases and normal sales. 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 (loss) and are recognized as a component of revenue when the hedged volumes are sold.

Our nonregulated segment also uses storage swaps and futures that have not been designated as hedges. Accordingly, changes in the fair value of the inventory and designated hedges are recognized in revenue in the period of change.

Finally, financial instruments used to mitigate interest rate risk are designated as cash flow hedges. Accordingly, unrealized gains and losses are recorded as a component of accumulated other comprehensive income (loss) and are recognized as a component of interest expense over the life of the related financing arrangement.

The criteria used to determine if a financial instrument meets the definition of a derivative and qualifies for hedge accounting treatment are complex and require management to exercise professional judgment. Further, as more fully discussed below, significant changes in the fair value of these financial instruments could materially impact our financial position, results of operations or cash flows.

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).

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) 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.

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. 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.

The fair value of our financial instruments is subject to potentially significant volatility based numerous considerations including, but not limited to changes in commodity prices, interest rates, maturity and settlement of these financial instruments, and our creditworthiness as well as the creditworthiness of our counterparties. 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.

Impairment assessments — We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstance indicate that such carrying values may not be recoverable, and at least annually for goodwill, as required by US accounting standards.

The evaluation of our goodwill balances and other long-lived assets or identifiable assets for which uncertainty exists regarding the recoverability of the carrying value of such assets involves the assessment of future cash flows and external market conditions and other subjective factors that could impact the estimation of future cash flows including, but not limited to the commodity prices, the amount and timing of future cash flows, future growth rates and the discount rate. Unforeseen events and changes in circumstances or market conditions could adversely affects these estimates, which could result in an impairment charge.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date 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. 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 periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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.

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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 and 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 $2.3 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $0.8 million.

Contingencies — In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties or the action of various regulatory agencies. For such matters, we record liabilities when they are considered probable and reasonably estimable, based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 13 to our consolidated financial statements.

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 56 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 fiscal 2012, we earned $216.7 million, or $2.37 per diluted share, which represents a four percent increase in net income and diluted net income per share over fiscal 2011. During fiscal 2012, recent improvements in rate designs in our natural gas distribution and regulated transmission and storage segments offset an eight percent year-over-year decline in consolidated natural gas distribution throughput due to warmer weather and a 21 percent decrease in nonregulated delivered gas sales due to a nine percent decrease in consolidated sales volumes as a result of warmer weather and a decrease in per-unit margins. Additionally, results for fiscal 2012 were influenced by several non-recurring items, which increased diluted earnings per share by $0.11.

On August 1, 2012, we completed the sale of substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $128 million, pursuant to an asset purchase agreement executed on May 12, 2011. In connection with the sale, we recognized a net of tax gain of approximately $6.3 million.

On August 8, 2012, we entered into an asset purchase agreement to sell all of our natural gas distribution assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $141 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals. Due to the pending sales transaction, the results of operations for our Georgia service area are shown in discontinued operations.

Our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On July 27, 2012 we issued a notice of early redemption of these notes on August 28, 2012. We initially funded the redemption through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility to repay the commercial paper borrowings utilized to redeem the notes. The facility bears interest at a one-month LIBOR based rate plus currently a margin of 0.875% which is based on the Company's credit rating. The short-term facility is expected to be repaid with the proceeds received from the issuance of new $350 million senior unsecured notes anticipated to occur in January 2013. In connection with the redemption, we paid a make-whole premium in accordance with the terms of the indenture and the Senior Notes and accrued interest at the time of redemption. In accordance with regulatory requirements, the premium will be deferred and will be recognized over the life of the new unsecured notes expected to be issued in January 2013.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2012, 2011 and 2010.

	For the Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Operating revenues	$3,438,483	$4,286,435	$4,661,060
Gross profit	1,323,739	1,300,820	1,314,136
Operating expenses	877,499	874,834	850,303
Operating income	446,240	425,986	463,833
Miscellaneous income (expense)	(14,644)	21,184	(591)
Interest charges	141,174	150,763	154,188
Income from continuing operations before income taxes	290,422	296,407	309,054
Income tax expense	98,226	106,819	119,203
Income from continuing operations	192,196	189,588	189,851
Income from discontinued operations, net of tax	18,172	18,013	15,988
Gain on sale of discontinued operations, net of tax	6,349	—	—
Net income	$ 216,717	$ 207,601	$ 205,839
Diluted net income per share from continuing operations	$ 2.10	$ 2.07	$ 2.03
Diluted net income per share from discontinued operations	$ 0.27	$ 0.20	$ 0.17
Diluted net income per share	$ 2.37	$ 2.27	$ 2.20

Regulated operations contributed 98 percent, 104 percent and 81 percent to our consolidated net income for fiscal years 2012, 2011 and 2010. 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		
	2012	2011	2010
	(In thousands)		
Natural gas distribution segment	$148,369	$162,718	$125,949
Regulated transmission and storage segment	63,059	52,415	41,486
Nonregulated segment	5,289	(7,532)	38,404
Net income	$216,717	$207,601	$205,839

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		
	2012	2011	2010
	(In thousands, except per share data)		
Regulated operations	$211,428	$215,133	$167,435
Nonregulated operations	5,289	(7,532)	38,404
Consolidated net income	$216,717	$207,601	$205,839
Diluted EPS from regulated operations	$ 2.31	$ 2.35	$ 1.79
Diluted EPS from nonregulated operations	0.06	(0.08)	0.41
Consolidated diluted EPS	$ 2.37	$ 2.27	$ 2.20

We reported net income of $216.7 million, or $2.37 per diluted share for the year ended September 30, 2012, compared with net income of $207.6 million or $2.27 per diluted share in the prior year. Income from continuing operations was $192.2 million, or $2.10 per diluted share compared with $189.6 million, or $2.07 per diluted share in the prior-year period. Income from discontinued operations was $24.5 million or $0.27 per diluted share for the year, which includes the gain on sale of substantially all our assets in Missouri, Illinois and

Iowa of $6.3 million, compared with $18.0 million or $0.20 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current year reduced net income by $5.0 million or $0.05 per diluted share compared with net losses recorded in the prior year of $6.6 million, or $0.07 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In fiscal 2011, net income included the net positive impact of several one-time items totaling $3.2 million, or $0.03 per diluted share related to the pre-tax items, which are discussed in further detail below. In fiscal 2012, net income includes the net positive impact of several one-time items totaling $10.3 million, or $0.11 per diluted share related to the following amounts:

- $13.6 million positive impact of a deferred tax rate adjustment.
- $10.0 million ($6.3 million, net of tax) unfavorable impact related to a one-time donation to a donor advised fund.
- $9.9 million ($6.3 million, net of tax) favorable impact related to the cash gain recorded in association with the August 1, 2012 completion of the sale of our Iowa, Illinois and Missouri assets.
- $5.3 million ($3.3 million, net of tax) unfavorable impact related to the noncash impairment of certain assets in our nonregulated business.

We reported net income of $207.6 million, or $2.27 per diluted share for the year ended September 30, 2011, compared with net income of $205.8 million or $2.20 per diluted share in the prior year. Income from continuing operations was $189.6 million, or $2.07 per diluted share compared with $189.9 million, or $2.03 per diluted share in the prior-year period. Income from discontinued operations was $18.0 million or $0.20 per diluted share for the year, compared with $16.0 million or $0.17 per diluted share in the prior year. Unrealized losses in our nonregulated operations during fiscal 2011 reduced net income by $6.6 million or $0.07 per diluted share compared with net losses recorded in fiscal 2010 of $4.3 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In fiscal 2010, net income included the net positive impact of a state sales tax refund of $4.6 million, or $0.05 per diluted share. In fiscal 2011, net income includes the net positive impact of several one-time items totaling $3.2 million, or $0.03 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $30.3 million unfavorable impact related to the noncash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

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, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore the cost of gas typically does not have an impact on our gross profit as 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.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs 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. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 75 percent of our residential and commercial margins.

As discussed above, on August 1, 2012, we completed the sale of substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa. On August 8, 2012 we entered into a definitive agreement to sell our natural gas distribution operations in Georgia. The results of these operations have been separately reported in the following tables and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	(In thousands, unless otherwise noted)				
Gross profit	$1,022,743	$1,017,943	$998,642	$ 4,800	$ 19,301
Operating expenses	718,282	695,855	701,791	22,427	(5,936)
Operating income	304,461	322,088	296,851	(17,627)	25,237
Miscellaneous income (expense)	(12,657)	16,242	1,132	(28,899)	15,110
Interest charges	110,642	115,740	118,147	(5,098)	(2,407)
Income from continuing operations before income taxes	181,162	222,590	179,836	(41,428)	42,754
Income tax expense	57,314	77,885	69,875	(20,571)	8,010
Income from continuing operations	123,848	144,705	109,961	(20,857)	34,744
Income from discontinued operations, net of tax	18,172	18,013	15,988	159	2,025
Gain on sale of discontinued operations, net of tax	6,349	—	—	6,349	—
Net Income	$ 148,369	$ 162,718	$125,949	$(14,349)	$ 36,769
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	244,466	275,540	307,474	(31,074)	(31,934)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	128,222	125,812	122,633	2,410	3,179
Consolidated natural gas distribution throughput from continuing operations — MMcf	372,688	401,352	430,107	(28,664)	(28,755)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	18,295	22,668	24,068	(4,373)	(1,400)
Total consolidated natural gas distribution throughput — MMcf	390,983	424,020	454,175	(33,037)	(30,155)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.43	$ 0.47	$ 0.47	$ (0.04)	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 4.64	$ 5.30	$ 5.77	$ (0.66)	$ (0.47)

Fiscal year ended September 30, 2012 compared with fiscal year ended September 30, 2011

The $4.8 million increase in natural gas distribution gross profit was primarily due to a $17.7 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Mississippi, West Texas and Kentucky service areas.

These increases were partially offset by the following:

- $11.1 million decrease in revenue-related taxes in our Mid-Tex, West Texas and Mississippi service areas, primarily due to lower revenues on which the tax is calculated.
- $1.6 million decrease due to an eight percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather in the current year compared to last year in most of our service areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income increased $22.4 million primarily due to the following:

- $11.2 million increase in legal costs, primarily due to settlements.
- $10.6 million increase in employee-related costs.
- $8.4 million increase in depreciation and amortization associated with an increase in our net plant as a result of our capital investments in the prior year.
- $2.6 million increase in software maintenance costs.

These increases were partially offset by the following:

- $6.8 million decrease in operating expenses due to increased capital spending and warmer weather allowing us time to complete more capital work than in the prior year.
- $2.9 million decrease due to the establishment of regulatory assets for pension and postretirement costs.

Miscellaneous income decreased $28.9 million primarily due to the absence of a $21.8 million pre-tax gain recognized in the prior year as a result of unwinding two Treasury locks ($13.6 million, net of tax) and a $10.0 million one-time donation to a donor advised fund in the current year.

Interest charges decreased $5.1 million compared to the prior year due primarily to the prepayment of our 5.125% $250 million senior notes in the fourth quarter of fiscal 2012, refinancing long-term debt at reduced interest rates and reducing commitment fees from decreasing the number of credit facilities and extending the length of their terms in fiscal 2011.

Additionally, results for fiscal 2012 were favorably impacted by a state tax benefit of $11.3 million. Due to the completion of the sale of our Missouri, Iowa and Illinois service areas in the fiscal fourth quarter, the Company updated its analysis of the tax rate at which deferred taxes would reverse in the future to reflect the sale of these service areas. The updated analysis supported a reduction in the deferred tax rate which when applied to the balance of taxable income deferred to future periods resulted in a reduction of the Company's overall deferred tax liability.

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

The $19.3 million increase in natural gas distribution gross profit primarily reflects a $38.6 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Kentucky and Kansas service areas.

These increases were partially offset by:

- $12.9 million decrease due to a seven percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather in fiscal 2011 compared to the same period in fiscal 2010 in most of our service areas.
- $8.1 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $5.9 million, primarily due to the following:

- $10.0 million decrease in taxes, other than income, due to lower revenue-related taxes.
- $6.4 million decrease in employee-related expenses.

These decreases were partially offset by:

- $5.4 million increase due to the absence of a state sales tax reimbursement received in fiscal 2010.
- $11.5 million increase in depreciation and amortization expense.
- $1.7 million increase in vehicles and equipment expense.

Net income for this segment for fiscal 2011 was also favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the fiscal years ended September 30, 2012, 2011 and 2010. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
			(In thousands)		
Mid-Tex	$142,755	$144,204	$134,655	$ (1,449)	$ 9,549
Kentucky/Mid-States	32,185	37,593	32,920	(5,408)	4,673
Louisiana	48,958	50,442	45,759	(1,484)	4,683
West Texas	27,875	29,686	33,509	(1,811)	(3,823)
Mississippi	27,369	26,338	26,441	1,031	(103)
Colorado-Kansas	23,898	25,920	24,543	(2,022)	1,377
Other	1,421	7,905	(976)	(6,484)	8,881
Total	$304,461	$322,088	$296,851	$(17,627)	$25,237

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 excess gas.

Our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex service area. 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 and demand for natural gas 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. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our 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, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$162,808	$125,973	$102,891	$36,835	$ 23,082
Third-party transportation	64,158	73,676	73,648	(9,518)	28
Storage and park and lend services	6,764	7,995	10,657	(1,231)	(2,662)
Other	13,621	11,729	15,817	1,892	(4,088)
Gross profit	247,351	219,373	203,013	27,978	16,360
Operating expenses	118,527	111,098	105,975	7,429	5,123
Operating income	128,824	108,275	97,038	20,549	11,237
Miscellaneous income (expense)	(1,051)	4,715	135	(5,766)	4,580
Interest charges	29,414	31,432	31,174	(2,018)	258
Income before income taxes	98,359	81,558	65,999	16,801	15,559
Income tax expense	35,300	29,143	24,513	6,157	4,630
Net income	$ 63,059	$ 52,415	$ 41,486	$10,644	$ 10,929
Gross pipeline transportation volumes — MMcf	640,732	620,904	634,885	19,828	(13,981)
Consolidated pipeline transportation volumes — MMcf	466,527	435,012	428,599	31,515	6,413

Fiscal year ended September 30, 2012 compared with fiscal year ended September 30, 2011

The $28.0 million increase in regulated transmission and storage gross profit compared to the prior year was primarily a result of the rate case that was finalized and became effective in May 2011 as well as the GRIP filings approved by the Railroad Commission of Texas (RRC) during fiscal 2011 and 2012. In May 2011, the RRC issued an order in the rate case of Atmos Pipeline — Texas that approved an annual operating income increase of $20.4 million. During fiscal 2011, the RRC approved the Atmos Pipeline — Texas GRIP filing with an annual operating income increase of $12.6 million that went into effect in the fiscal fourth quarter. On April 10, 2012, the RRC approved the Atmos Pipeline — Texas GRIP filing with an annual operating income increase of $14.7 million that went into effect with bills rendered on an after April 10, 2012.

Operating expenses increased $7.4 million primarily due to a $5.4 million increase in depreciation expense, resulting from higher investment in net plant.

Additionally, results for fiscal 2012 were favorably impacted by a state tax benefit of $2.3 million associated with an update of the estimated tax rate at which deferred taxes would reverse in future periods after the completion of the sale of our Missouri, Illinois and Iowa assets. Net income for this segment for the prior year was favorably impacted by a $6.0 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks ($3.9 million, net of tax).

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

On April 18, 2011, the RRC issued an order in the rate case of Atmos Pipeline — Texas (APT) that was originally filed in September 2010. The RRC approved an annual operating income increase of $20.4 million as well as the following major provisions that went into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity.

- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- An annual adjustment mechanism, which was approved for a three-year pilot program, that will adjust regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly customer charges.

The $16.4 million increase in regulated transmission and storage gross profit was attributable primarily to the following:

- $23.4 million net increase as a result of the rate case that was finalized and became effective in May 2011.
- $3.2 million increase associated with our most recent GRIP filing.

These increases were partially offset by the following:

- $4.8 million decrease due to the absence of the sale of excess gas, which occurred in the prior year.
- $4.4 million decrease due to a decline in throughput to our Mid-Tex Division primarily due to warmer than normal weather during fiscal 2011.

Operating expenses increased $5.1 million primarily due to the following:

- $4.6 million increase due to higher depreciation expense.
- $2.0 million increase due to the absence of a state sales tax reimbursement received in the prior year.

These increases were partially offset by the following:

- $0.8 million decrease related to lower levels of pipeline maintenance activities.
- $0.7 million decrease due to lower employee-related expenses.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. These activities are reflected as gas delivery and related services in the table below.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. Most of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight. These activities are reflected as storage and transportation services in the table below.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments in an effort to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions.

Our nonregulated activities are significantly influenced by competitive factors in the industry and general economic conditions. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of gas and demand fees paid to contract for storage capacity to offer more competitive pricing to those customers.

Further, natural gas market conditions, most notably the price of natural gas and the level of price volatility affect our nonregulated businesses. Natural gas prices and the level of volatility are influenced by a number of factors including, but not limited to, general economic conditions, the demand for natural gas in different parts of the country, the level of domestic natural gas production and the level of natural gas inventory levels.

Natural gas prices can influence:

- The demand for natural gas. Higher prices may cause customers to conserve or use alternative energy sources. Conversely, lower prices could cause customers such as electric power generators to switch from alternative energy sources to natural gas.
- Collection of accounts receivable from customers, which could affect the level of bad debt expense recognized by this segment.
- The level of borrowings under our credit facilities, which affects the level of interest expense recognized by this segment.

Natural gas price volatility can also influence our nonregulated business in the following ways:

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Price volatility also influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads.
- 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.

Our nonregulated segment manages its exposure to natural gas commodity price risk through a combination of physical storage and financial instruments. Therefore, results for this segment include unrealized gains or losses on its net physical gas position and the related financial instruments used to manage commodity price risk. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will generally record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the fiscal years ended September 30, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$ 46,578	$ 58,990	$ 59,523	$(12,412)	$ (533)
Storage and transportation services	13,382	14,570	13,206	(1,188)	1,364
Other	3,737	5,265	5,347	(1,528)	(82)
	63,697	78,825	78,076	(15,128)	749
Asset optimization[1]	(558)	(3,424)	43,805	2,866	(47,229)
Total realized margins	63,139	75,401	121,881	(12,262)	(46,480)
Unrealized margins	(8,015)	(10,401)	(7,790)	2,386	(2,611)
Gross profit	55,124	65,000	114,091	(9,876)	(49,091)
Operating expenses, excluding asset impairment	36,886	39,113	44,147	(2,227)	(5,034)
Asset impairment	5,288	30,270	—	(24,982)	30,270
Operating income (loss)	12,950	(4,383)	69,944	17,333	(74,327)
Miscellaneous income	1,035	657	3,859	378	(3,202)
Interest charges	3,084	4,015	10,584	(931)	(6,569)
Income (loss) before income taxes	10,901	(7,741)	63,219	18,642	(70,960)
Income tax expense (benefit)	5,612	(209)	24,815	5,821	(25,024)
Net income (loss)	$ 5,289	$ (7,532)	$ 38,404	$ 12,821	$(45,936)
Gross nonregulated delivered gas sales volumes — MMcf	400,512	446,903	420,203	(46,391)	26,700
Consolidated nonregulated delivered gas sales volumes — MMcf	351,628	384,799	353,853	(33,171)	30,946
Net physical position (Bcf)	18.8	21.0	15.7	(2.2)	5.3

[1] Net of storage fees of $18.4 million, $15.2 million and $13.2 million.

Fiscal year ended September 30, 2012 compared with fiscal year ended September 30, 2011

Results for our nonregulated operations during fiscal 2012 were adversely influenced by continued unfavorable natural gas market conditions. Historically high natural gas storage levels from strong domestic natural gas production caused natural gas prices to remain relatively low during fiscal 2012. Additionally, we continued to experience compressed spot to forward spread values and basis differentials.

We anticipate these natural gas market conditions will continue for the foreseeable future. As a result, we anticipate that basis differentials will remain compressed and spot-to-forward price volatility will remain relatively low. Accordingly, although we anticipate continuing to profit on a fiscal-year basis from our nonregulated activities, we anticipate per-unit margins from our delivered gas activities and margins earned from our asset optimization activities for the foreseeable future to be more consistent with the performance we have experienced during the last two fiscal years.

Realized margins for gas delivery, storage and transportation services and other services were $63.7 million during the year ended September 30, 2012 compared with $78.8 million for the prior year. The decrease reflects the following:

- A nine percent decrease in consolidated sales volumes. The decrease was largely attributable to warmer weather, which reduced sales to utility, municipal and other weather-sensitive customers.
- A $0.02/Mcf decrease in gas delivery per-unit margins compared to the prior year primarily due to lower basis differentials resulting from increased natural gas supply and increased transportation costs.

Asset optimization margins increased $2.9 million from the prior year. The increase primarily reflects higher realized margins earned from the settlement of financial instruments used to hedge our natural gas inventory purchases, partially offset by increased storage fees associated with increased park and loan activity and a $1.7 million charge in the first fiscal quarter of the current year to write down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

Unrealized margins increased $2.4 million in the current year compared to the prior year primarily due to the timing of year-over-year realized margins.

Operating expenses, excluding asset impairments decreased $2.2 million primarily due to lower employee-related expenses.

During the fourth quarter of fiscal 2012, we recorded a $5.3 million noncash charge to impair our natural gas gathering assets located in Kentucky. The charge reflected a reduction in the value of the project due to the current low natural gas price environment and management's decision to focus AEH's activities on its gas delivery, storage and transportation services. In the prior year, asset impairments included an asset impairment charge of $19.3 million related to our investment in our Fort Necessity storage project as well as an $11.0 million pre-tax impairment charge related to the write-off of certain natural gas gathering assets.

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

Realized margins for gas delivery, storage and transportation services and other services were $78.8 million during the year ended September 30, 2011 compared with $78.1 million for the prior-year period. The increase primarily reflects the following:

- $1.4 million increase in margins from storage and transportation services, primarily attributable to new drilling projects in the Barnett Shale area.
- $0.6 million decrease in gas delivery and other services primarily due to lower per-unit margins partially offset by a nine percent increase in consolidated delivered gas sales volumes due to new customers in the power generation market. Per-unit margins were $0.13/Mcf in the current year compared with $0.14/Mcf in the prior year. The year-over-year decrease in per-unit margins reflects the impact of increased competition and lower basis spreads.

The $47.2 million decrease in realized asset optimization margins from the prior year primarily reflects the unfavorable impact of weak natural gas market fundamentals which provided fewer favorable trading opportunities.

Unrealized margins decreased $2.6 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses decreased $5.0 million primarily due to lower employee-related expenses and ad valorem taxes.

During fiscal 2011, our nonregulated segment recognized $30.3 million of noncash asset impairment charges associated with the two aforementioned projects.

Interest charges decreased $6.6 million primarily due to a decrease in intercompany borrowings.

LIQUIDITY AND CAPITAL RESOURCES

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

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require.

Our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On August 28, 2012 we redeemed these notes with proceeds received through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility that expires February 1, 2013 to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds from the $350 million 30-year unsecured senior notes, which are expected to be issued in January 2013. We fixed the Treasury yield component of the interest cost associated with these anticipated senior notes at 4.07% by executing three Treasury lock agreements in August 2011. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for fiscal year 2013.

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, 2012, 2011 and 2010 are presented below.

	For the Fiscal Year Ended September 30				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
			(In thousands)		
Total cash provided by (used in)					
Operating activities	$ 586,917	$ 582,844	$ 726,476	$ 4,073	$(143,632)
Investing activities	(609,260)	(627,386)	(542,702)	18,126	(84,684)
Financing activities	(44,837)	44,009	(163,025)	(88,846)	207,034
Change in cash and cash equivalents	(67,180)	(533)	20,749	(66,647)	(21,282)
Cash and cash equivalents at beginning of period	131,419	131,952	111,203	(533)	20,749
Cash and cash equivalents at end of period	$ 64,239	$ 131,419	$ 131,952	$(67,180)	$ (533)

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, 2012 compared with fiscal year ended September 30, 2011

For the fiscal year ended September 30, 2012, we generated operating cash flow of $586.9 million from operating activities compared with $582.8 million in the prior year. The year-over-year increase reflects changes in working capital offset by the $56.7 million increase in contributions made to our pension and postretirement plans during fiscal 2012.

Fiscal Year ended September 30, 2011 compared with fiscal year ended September 30, 2010

For the fiscal year ended September 30, 2011, we generated operating cash flow of $582.8 million from operating activities compared with $726.5 million in fiscal September 30, 2010. The year-over-year decrease reflects the absence of an $85 million income tax refund received in the prior year coupled with the timing of gas cost recoveries under our purchased gas cost mechanisms and other net working capital changes.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide safe and reliable 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.

In early fiscal 2010, two coalitions of cities, representing the majority of the cities our Mid-Tex Division serves, agreed to a program of installing, beginning in the first quarter of fiscal 2011, 100,000 steel service line replacements during fiscal 2011 and 2012, with approved recovery of the associated return, depreciation and taxes for lines replaced between October 1, 2010 and September 30, 2012. As of September 30, 2012, we had replaced 98,675 lines. Since October 1, 2010 we have spent $116.3 million on steel service line replacements.

For the fiscal year ended September 30, 2012, we incurred $732.9 million for capital expenditures compared with $623.0 million for the fiscal year ended September 30, 2011 and $542.6 million for the fiscal year ended September 30, 2010.

The $109.9 million increase in capital expenditures in fiscal 2012 compared to fiscal 2011 primarily reflects spending for the steel service line replacement program in the Mid-Tex Division, the development of new customer billing and information systems for our natural gas distribution and our nonregulated segments and increased capital spending to increase the capacity on our Atmos Pipeline — Texas system. As a result of these projects, we anticipate capital expenditures will remain elevated during the next fiscal year.

The $80.4 million increase in capital expenditures in fiscal 2011 compared to fiscal 2010 primarily reflects spending for the steel service line replacement program in the Mid-Tex Division, the development of new customer billing and information systems for our natural gas distribution and our nonregulated segments and the construction of a new customer contact center in Amarillo, Texas, partially offset by costs incurred in the prior fiscal year to relocate the company's information technology data center.

Cash flows from financing activities

For the fiscal year ended September 30, 2012, our financing activities used $44.8 million in cash, while financing activities for the fiscal year ended September 30, 2011 generated $44.0 million in cash compared with cash of $163.0 million used for the fiscal year ended September 30, 2010. Our significant financing activities for the fiscal years ended September 30, 2012, 2011 and 2010 are summarized as follows:

2012

During the fiscal year ended September 30, 2012, we:

- Paid $257.0 million for long-term debt repayments, including the early redemption of our $250 million 5.125% Senior notes that were scheduled to mature in January 2013.

- Borrowed $260 million under a short-term loan to finance the repayment of our $250 million 5.125% Senior notes.
- Borrowed a net $94.1 million under our short-term facilities, excluding the $260 million short-term loan used to finance the early redemption of our $250 million 5.125% Senior notes, to fund working capital needs.
- Paid $125.8 million in cash dividends, which reflected a payout ratio of 58 percent of net income.
- Paid $12.5 million for the repurchase of common stock as part of our share buyback program.
- Paid $5.2 million for the repurchase of equity awards.

2011

During the fiscal year ended September 30, 2011, we:

- Received $394.5 million net cash proceeds in June 2011 related to the issuance of $400 million 5.50% senior notes due 2041.
- Borrowed a net $83.3 million under our short-term facilities to fund working capital needs.
- Received $27.8 million cash in March 2011 related to the unwinding of two Treasury locks.
- Received $20.1 million cash in June 2011 related to the settlement of three Treasury locks associated with the $400 million 5.50% senior notes offering.
- Received $7.8 million net proceeds related to the issuance of 0.3 million shares of common stock.
- Paid $360.1 million for scheduled long-term debt repayments, including our $350 million 7.375% senior notes that were paid on their maturity date on May 15, 2011.
- Paid $124.0 million in cash dividends which reflected a payout ratio of 60 percent of net income.
- Paid $5.3 million for the repurchase of equity awards.

2010

During the fiscal year ended September 30, 2010, we:

- Paid $124.3 million in cash dividends which reflected a payout ratio of 61 percent of net income.
- Paid $100.5 million for the repurchase of common stock under an accelerated share repurchase agreement.
- Borrowed a net $54.3 million under our short-term facilities due to the impact of seasonal natural gas purchases.
- Received $8.8 million net proceeds related to the issuance of 0.4 million shares of common stock, which is a 68 percent decrease compared to the prior year due primarily to the fact that beginning in fiscal 2010 shares were purchased on the open market rather than being issued by us to the Direct Stock Purchase Plan and the Retirement Savings Plan.
- Paid $1.2 million to repurchase equity awards.

The following table shows the number of shares issued for the fiscal years ended September 30, 2012, 2011 and 2010:

	For the Fiscal Year Ended September 30		
	2012	2011	2010
Shares issued:			
Direct stock purchase plan	—	—	103,529
Retirement savings plan	—	—	79,722
1998 Long-term incentive plan	482,289	675,255	421,706
Outside directors stock-for-fee plan	2,375	2,385	3,382
Total shares issued	484,664	677,640	608,339

The decreased number of shares issued in fiscal 2012 compared with the number of shares issued in fiscal 2011 primarily reflects a decrease in the number of shares issued under our 1998 Long-Term Incentive Plan (LTIP), due to the exercise of a significant number of stock options during fiscal 2011. During fiscal 2012, we cancelled and retired 153,255 shares attributable to federal withholdings on equity awards and repurchased and retired 387,991 shares attributable to our share repurchase program, which are not included in the table above.

The increase in the number of shares issued in fiscal 2011 compared with the number of shares issued in fiscal 2010 primarily reflects an increased number of shares issued under our LTIP due to the exercise of a significant number of stock options during fiscal 2011. This increase was partially offset by the fact that we purchased shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During fiscal 2011, we cancelled and retired 169,793 shares attributable to federal withholdings on equity awards and repurchased and retired 375,468 shares attributable to our 2010 accelerated share repurchase agreement, which are not included in the table above.

As of September 30, 2011, we were authorized to grant awards for up to a maximum of 6.5 million shares of common stock under our LTIP. In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange.

Credit Facilities

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

We finance our short-term borrowing requirements through a combination of a $750 million commercial paper program collateralized by our $750 million unsecured credit facility and four committed revolving credit facilities with third-party lenders. As a result, we have approximately $989 million of working capital funding. Additionally, our $750 million unsecured credit facility has an accordion feature, which, if utilized, would increase borrowing capacity to $1.0 billion. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. With the closing of the sale of our Missouri, Illinois and Iowa operations on August 1, 2012, there are no longer any restrictions on our ability to issue either debt or equity under the shelf until it expires on March 31, 2013, with $900 million available for issuance at September 30, 2012. We intend to file a new shelf registration statement with the SEC for at least $1.3 billion prior to the expiration of the current shelf.

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 environment in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa1	A-
Commercial paper	A-2	P-2	F-2

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2012. Our debt covenants are described in Note 7 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2012 and 2011:

	September 30			
	2012		2011	
	(In thousands, except percentages)			
Short-term debt	$ 570,929	11.7%	$ 206,396	4.4%
Long-term debt	1,956,436	40.0%	2,208,551	47.3%
Shareholders' equity	2,359,243	48.3%	2,255,421	48.3%
Total capitalization, including short-term debt	$4,886,608	100.0%	$4,670,368	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.7 percent at September 30, 2012 and 2011. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to continue to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2012.

	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]	$1,960,131	$ 131	$500,000	$250,000	$1,210,000
Short-term debt[1]	570,929	570,929	—	—	—
Interest charges[2]	1,434,549	123,572	223,346	192,960	894,671
Gas purchase commitments[3]	333,839	259,235	74,604	—	—
Capital lease obligations[4]	1,008	186	372	372	78
Operating leases[4]	180,991	17,571	33,155	29,633	100,632
Demand fees for contracted storage[5]	9,473	6,285	2,986	74	128
Demand fees for contracted transportation[6]	25,484	13,171	12,072	241	—
Financial instrument obligations[7]	94,587	85,381	9,206	—	—
Postretirement benefit plan contributions[8]	207,636	28,317	32,523	39,741	107,055
Uncertain tax positions (including interest)[9]	1,831	—	1,831	—	—
Total contractual obligations[10]	$4,820,458	$1,104,778	$890,095	$513,021	$2,312,564

(1) See Note 7 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, 2012.

(4) See Note 14 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our nonregulated segment. 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 nonregulated segment.

(7) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2012. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled. The table above excludes $0.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Georgia operations.

(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.

(10) Total contractual obligations exclude pension plan contributions, which are discussed in Note 9. We anticipate contributing between $30 million and $40 million to these plans during fiscal 2013.

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2012, AEH was committed to purchase 72.2 Bcf within one year, 29.0 Bcf within one to three years and 29.0 Bcf after three years under indexed contracts. AEH is committed to purchase 3.8 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $2.46 to $6.36 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 individual contracts. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of natural gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under the terms of these contracts as of September 30, 2012 are reflected in the table above.

Risk Management Activities

As discussed above in our Critical Accounting Policies, 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 and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our nonregulated 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 nonregulated 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 nonregulated segment.

Also, in our nonregulated 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, 2012 (in thousands):

Fair value of contracts at September 30, 2011	$(79,277)
Contracts realized/settled	(32,027)
Fair value of new contracts	4,782
Other changes in value	30,262
Fair value of contracts at September 30, 2012	$ (76,260)

The fair value of our natural gas distribution segment's financial instruments at September 30, 2012, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2012				
	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	$(78,543)	$2,283	$—	$—	$(76,260)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(78,543)	$2,283	$—	$—	$(76,260)

The tables above include $0.1 million of current assets from risk management activities that are classified as assets held for sale and $0.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Georgia operations.

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the fiscal year ended September 30, 2012 (in thousands):

Fair value of contracts at September 30, 2011	$(25,050)
Contracts realized/settled	15,677
Fair value of new contracts	—
Other changes in value	(5,750)
Fair value of contracts at September 30, 2012	(15,123)
Netting of cash collateral	23,675
Cash collateral and fair value of contracts at September 30, 2012	$ 8,552

The fair value of our nonregulated segment's financial instruments at September 30, 2012, is presented below by time period and fair value source.

	Fair Value of Contracts at September 30, 2012				
	Maturity in years				
Source of Fair Value	Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(5,917)	$(9,222)	$16	$—	$(15,123)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(5,917)	$(9,222)	$16	$—	$(15,123)

Employee Benefits Programs

An important element of our total compensation program, and a significant component of our operation and maintenance expense, is the offering of various benefits programs to our employees. These programs include medical and dental insurance coverage and pension and postretirement programs.

Medical and Dental Insurance

We offer medical and dental insurance programs to substantially all of our employees, and we believe these programs are consistent with other programs in our industry. Since 2006, we have experienced medical and prescription inflation of approximately six percent. In recent years, we have strived to actively manage our health care costs through the introduction of a wellness strategy that is focused on helping employees to identify health risks and to manage these risks through improved lifestyle choices.

In March 2010, President Obama signed *The Patient Protection and Affordable Care Act* into law (the "Health Care Reform Act"). The Health Care Reform Act will be phased in over an eight-year period. We have changed the design of our health care plans to comply with provisions of the Health Care Reform Act that have already gone into effect or will be going into effect in future years. For example, lifetime maximums on benefits have been eliminated, coverage for dependent children has been extended to age 26 and all costs of preventive coverage must be paid for by the insurer. In 2014, health insurance exchanges will open in each state in order to provide a competitive marketplace for purchasing health insurance by individuals. Companies who offer health insurance to their employees could face a substantial increase in premiums at that time if they choose to continue to provide such coverage. However, companies who elect to cease providing health insurance to their employees will be faced with paying significant penalties to the federal government for each employee who receives coverage through an exchange. We will continue to monitor all developments on health care reform and continue to comply with all existing relevant laws and regulations.

For fiscal 2013, we anticipate an approximate seven percent medical and prescription drug inflation rate, primarily due to anticipated higher claims costs and the implementation of the Health Care Reform Act.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2012, our total net periodic pension and other benefits costs was $69.2 million, compared with $56.6 million and $50.8 million for the fiscal years ended September 30, 2011 and 2010. 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.

Our fiscal 2012 costs were determined using a September 30, 2011 measurement date. At that date, interest and corporate bond rates utilized to determine our discount rates were significantly lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. Our expected return on our pension plan assets was reduced to 7.75 percent due to historical experience and the current market projection of the target asset allocation. As a result, our fiscal 2012 pension and postretirement medical costs were higher than in the prior year.

The increase in total net periodic pension and other benefits costs during fiscal 2011 compared with fiscal 2010 primarily reflects the decrease in our discount rate at September 30, 2010, the measurement date for our fiscal 2011 pension and postretirement costs. 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, 2010 measurement date, the interest rates were significantly higher than the interest rates at September 30, 2009, the measurement date used to determine our fiscal 2009 net periodic cost. 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 (ERISA). 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.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2012. Based on this valuation, we were required to contribute cash of $46.5 million to our pension plans during fiscal 2012. The need for this funding primarily reflects a decrease in the discount rate used to determine our obligations under our plans. This contribution increased the level of our plan assets to achieve a desirable PPA funding threshold.

During fiscal 2011, we were required to contribute cash of $0.9 million to our pension plans. The need for this funding reflected the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution increased the level of our plan assets to achieve a desirable PPA funding threshold. During fiscal 2010, we did not contribute cash to our pension plans as the fair value of the plans' assets recovered somewhat during the year from the unfavorable market conditions experienced in the latter half of calendar year 2008 and our plan assets were sufficient to achieve a desirable funding threshold as established by the PPA.

We contributed $22.1 million, $11.3 million and $11.8 million to our postretirement benefits plans for the fiscal years ended September 30, 2012, 2011 and 2010. 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 2013 and Beyond

As of September 30, 2012, interest and corporate bond rates utilized to determine our discount rates, which impacted our fiscal 2013 net periodic pension and postretirement costs, were lower than the interest and corporate bond rates as of September 30, 2011, the measurement date for our fiscal 2012 net periodic cost. As a result of the lower interest and corporate bond rates, we decreased the discount rate used to determine our fiscal 2013 pension and benefit costs to 4.04 percent. We maintained the expected return on our pension plan assets at 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Due to the decrease in our discount rate, we expect our fiscal 2013 pension and postretirement medical costs to increase compared to fiscal 2012.

Based upon market conditions subsequent to September 30, 2012 the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $30 million and $40 million to the Plans in fiscal 2013. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. With respect to our postretirement medical plans, we anticipate contributing between $25 million and $30 million during fiscal 2013.

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.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP have continued to earn benefits and interest allocations with no changes to their existing benefits.

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 nonregulated 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 nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. 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.

Nonregulated segment

Our nonregulated segment is also exposed to risks associated with changes in the market price of natural gas. For our nonregulated 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, 2012 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, 2012 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 $5.8 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 $2.5 million during 2012.

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

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, 2012 and 2011, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2012, 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), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2012, 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 12, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2012

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2012	September 30 2011
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,860,358	$6,607,552
Construction in progress	274,112	209,242
	7,134,470	6,816,794
Less accumulated depreciation and amortization	1,658,866	1,668,876
Net property, plant and equipment	5,475,604	5,147,918
Current assets		
Cash and cash equivalents	64,239	131,419
Accounts receivable, less allowance for doubtful accounts of $9,425 in 2012 and $7,440 in 2011	234,526	273,303
Gas stored underground	256,415	289,760
Other current assets	272,782	316,471
Total current assets	827,962	1,010,953
Goodwill and intangible assets	740,847	740,207
Deferred charges and other assets	451,262	383,793
	$7,495,675	$7,282,871
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2012 — 90,239,900 shares, 2011 — 90,296,482 shares	$ 451	$ 451
Additional paid-in capital	1,745,467	1,732,935
Accumulated other comprehensive loss	(47,607)	(48,460)
Retained earnings	660,932	570,495
Shareholders' equity	2,359,243	2,255,421
Long-term debt	1,956,305	2,206,117
Total capitalization	4,315,548	4,461,538
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	215,229	291,205
Other current liabilities	489,665	367,563
Short-term debt	570,929	206,396
Current maturities of long-term debt	131	2,434
Total current liabilities	1,275,954	867,598
Deferred income taxes	1,015,083	960,093
Regulatory cost of removal obligation	381,164	428,947
Deferred credits and other liabilities	507,926	564,695
	$7,495,675	$7,282,871

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,145,330	$2,470,664	$2,783,863
Regulated transmission and storage segment	247,351	219,373	203,013
Nonregulated segment	1,351,303	2,024,893	2,146,658
Intersegment eliminations	(305,501)	(428,495)	(472,474)
	3,438,483	4,286,435	4,661,060
Purchased gas cost			
Natural gas distribution segment	1,122,587	1,452,721	1,785,221
Regulated transmission and storage segment	—	—	—
Nonregulated segment	1,296,179	1,959,893	2,032,567
Intersegment eliminations	(304,022)	(426,999)	(470,864)
	2,114,744	2,985,615	3,346,924
Gross profit	1,323,739	1,300,820	1,314,136
Operating expenses			
Operation and maintenance	453,613	442,965	454,621
Depreciation and amortization	237,525	223,832	208,539
Taxes, other than income	181,073	177,767	187,143
Asset impairments	5,288	30,270	—
Total operating expenses	877,499	874,834	850,303
Operating income	446,240	425,986	463,833
Miscellaneous income (expense), net	(14,644)	21,184	(591)
Interest charges	141,174	150,763	154,188
Income from continuing operations before income taxes	290,422	296,407	309,054
Income tax expense	98,226	106,819	119,203
Income from continuing operations	192,196	189,588	189,851
Income from discontinued operations, net of tax ($10,066, $12,372 and $9,584)	18,172	18,013	15,988
Gain on sale of discontinued operations, net of tax ($3,519, $0 and $0)	6,349	—	—
Net income	$ 216,717	$ 207,601	$ 205,839
Basic earnings per share			
Income per share from continuing operations	$ 2.12	$ 2.08	$ 2.05
Income per share from discontinued operations	0.27	0.20	0.17
Net income per share — basic	$ 2.39	$ 2.28	$ 2.22
Diluted earnings per share			
Income per share from continuing operations	$ 2.10	$ 2.07	$ 2.03
Income per share from discontinued operations	0.27	0.20	0.17
Net income per share — diluted	$ 2.37	$ 2.27	$ 2.20
Weighted average shares outstanding:			
Basic	90,150	90,201	91,852
Diluted	91,172	90,652	92,422

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock		Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Number of Shares	Stated Value				
	(In thousands, except share and per share data)					
Balance, September 30, 2009	92,551,709	$463	$1,791,129	$(20,184)	$ 405,353	$2,176,761
Comprehensive income:						
Net income	—	—	—	—	205,839	205,839
Unrealized holding gains on investments, net of tax of $1,025	—	—	—	1,745	—	1,745
Treasury lock agreements, net of tax of $1,193	—	—	—	2,030	—	2,030
Cash flow hedges, net of tax of $(4,452)	—	—	—	(6,963)	—	(6,963)
Total comprehensive income						202,651
Repurchase of common stock	(2,958,580)	(15)	(100,435)	—	—	(100,450)
Repurchase of equity awards	(37,365)	—	(1,191)	—	—	(1,191)
Cash dividends ($1.34 per share)	—	—	—	—	(124,287)	(124,287)
Common stock issued:						
Direct stock purchase plan	103,529	1	2,881	—	—	2,882
Retirement savings plan	79,722	—	2,281	—	—	2,281
1998 Long-term incentive plan	421,706	2	8,708	—	—	8,710
Employee stock-based compensation	—	—	10,894	—	—	10,894
Outside directors stock-for-fee plan	3,382	—	97	—	—	97
Balance, September 30, 2010	90,164,103	451	1,714,364	(23,372)	486,905	2,178,348
Comprehensive income:						
Net income	—	—	—	—	207,601	207,601
Unrealized holding losses on investments, net of tax of $(953)	—	—	—	(1,647)	—	(1,647)
Treasury lock agreements, net of tax of $(16,850)	—	—	—	(28,689)	—	(28,689)
Cash flow hedges, net of tax of $3,355	—	—	—	5,248	—	5,248
Total comprehensive income						182,513
Repurchase of common stock	(375,468)	(2)	2	—	—	—
Repurchase of equity awards	(169,793)	(1)	(5,298)	—	—	(5,299)
Cash dividends ($1.36 per share)	—	—	—	—	(124,011)	(124,011)
Common stock issued:						
Direct stock purchase plan	—	—	(54)	—	—	(54)
1998 Long-term incentive plan	675,255	3	13,886	—	—	13,889
Employee stock-based compensation	—	—	9,958	—	—	9,958
Outside directors stock-for-fee plan	2,385	—	77	—	—	77
Balance, September 30, 2011	90,296,482	451	1,732,935	(48,460)	570,495	2,255,421
Comprehensive income:						
Net income	—	—	—	—	216,717	216,717
Unrealized holding gains on investments, net of tax of $1,881	—	—	—	3,103	—	3,103
Treasury lock agreements, net of tax of $(5,388)	—	—	—	(10,116)	—	(10,116)
Cash flow hedges, net of tax of $5,029	—	—	—	7,866	—	7,866
Total comprehensive income						217,570
Repurchase of common stock	(387,991)	(2)	(12,533)	—	—	(12,535)
Repurchase of equity awards	(153,255)	—	(5,219)	—	—	(5,219)
Cash dividends ($1.38 per share)	—	—	—	—	(125,796)	(125,796)
Common stock issued:						
Direct stock purchase plan	—	—	(65)	—	—	(65)
1998 Long-term incentive plan	482,289	2	12,519	—	(484)	12,037
Employee stock-based compensation	—	—	17,752	—	—	17,752
Outside directors stock-for-fee plan	2,375	—	78	—	—	78
Balance, September 30, 2012	90,239,900	$451	$1,745,467	$(47,607)	$ 660,932	$2,359,243

See accompanying notes to consolidated financial statements.

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended September 30		
	2012	2011	2010
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 216,717	$ 207,601	$ 205,839
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	5,288	30,270	—
Gain on sale of discontinued operations	(9,868)	—	—
Depreciation and amortization:			
Charged to depreciation and amortization	246,093	233,155	216,960
Charged to other accounts	484	228	173
Deferred income taxes	104,319	117,353	196,731
Stock-based compensation	19,222	11,586	12,655
Debt financing costs	8,147	9,438	11,908
Other	(493)	(961)	(1,245)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	32,578	(96)	(40,401)
Decrease in gas stored underground	28,417	27,737	54,014
(Increase) decrease in other current assets	20,989	(38,048)	(18,387)
(Increase) decrease in deferred charges and other assets	(50,055)	(53,519)	14,886
Increase (decrease) in accounts payable and accrued liabilities	(64,234)	23,904	58,069
Increase (decrease) in other current liabilities	7,889	(57,495)	(48,992)
Increase in deferred credits and other liabilities	21,424	71,691	64,266
Net cash provided by operating activities	586,917	582,844	726,476
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(732,858)	(622,965)	(542,636)
Proceeds from the sale of discontinued operations	128,223	—	—
Other, net	(4,625)	(4,421)	(66)
Net cash used in investing activities	(609,260)	(627,386)	(542,702)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase in short-term debt	354,141	83,306	54,268
Net proceeds from issuance of long-term debt	—	394,466	—
Settlement of Treasury lock agreements	—	20,079	—
Unwinding of Treasury lock agreements	—	27,803	—
Repayment of long-term debt	(257,034)	(360,131)	(131)
Cash dividends paid	(125,796)	(124,011)	(124,287)
Repurchase of common stock	(12,535)	—	(100,450)
Repurchase of equity awards	(5,219)	(5,299)	(1,191)
Issuance of common stock	1,606	7,796	8,766
Net cash provided by (used in) financing activities	(44,837)	44,009	(163,025)
Net increase (decrease) in cash and cash equivalents	(67,180)	(533)	20,749
Cash and cash equivalents at beginning of year	131,419	131,952	111,203
Cash and cash equivalents at end of year	$ 64,239	$ 131,419	$ 131,952

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 non-regulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public-authority and industrial customers through our six regulated natural gas distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas
Atmos Energy Kentucky/Mid-States Division	Georgia[1], Kentucky, 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.

On August 1, 2012, we completed the divesture of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. On August 8, 2012, we entered into a definitive agreement to sell our natural gas distribution operations in Georgia, representing approximately 64,000 customers. The results of these operations have been separately reported as discontinued operations.

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 through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties.

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; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Basis of comparison — Certain prior-year amounts have been reclassified to conform with the current year presentation.

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, unbilled revenues, 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, 2012 and 2011 included the following:

	September 30	
	2012	2011
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$296,160	$254,666
Merger and integration costs, net	5,754	6,242
Deferred gas costs	31,359	33,976
Regulatory cost of removal asset	10,500	8,852
Rate case costs	4,661	4,862
Deferred franchise fees	2,714	379
Risk-based replacement program costs	5,370	—
APT annual adjustment mechanism	4,539	—
Other	7,262	3,919
	$368,319	$312,896
Regulatory liabilities:		
Deferred gas costs	$ 23,072	$ 8,130
Regulatory cost of removal obligation	459,688	464,025
APT annual adjustment mechanism	—	6,654
Other	5,637	7,371
	$488,397	$486,180

During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of September 30, 2012, we had deferred $5.4 million associated with the requirements of this rule.

Effective January 1, 2012, the Texas Legislature amended its Gas Utility Regulatory Act (GURA) to permit natural gas utilities to defer into a regulatory asset or liability the difference between a gas utility's actual pension and postretirement expense and the level of such expense recoverable in its existing rates. The deferred amount will become eligible for inclusion in the utility's rates in its next rate proceeding. We elected to utilize this provision of GURA, effective January 1, 2012, and established a regulatory asset totaling $7.6 million, which is recorded in "Pension and postretirement benefit costs" in the regulatory assets table above. Of this amount, $4.2 million represented a reduction to operation and maintenance expense during fiscal 2012.

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. During the fiscal years ended September 30, 2012, 2011 and 2010, we recognized $0.5 million, $0.5 million and $0.4 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.

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 nonregulated 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 nonregulated 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, 2012, 2011 and 2010, we included unrealized gains (losses) on open contracts of $(8.0) million, $(10.4) million and $(7.8) million as a component of nonregulated revenues.

Operating revenues for our regulated transmission and storage and nonregulated 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 substantially all 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 nonregulated segment 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 nonregulated segment utilizes 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 $2.6 million, $1.7 million and $3.9 million was capitalized in 2012, 2011 and 2010.

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 3.6 percent, 3.6 percent and 3.5 percent for the fiscal years ended September 30, 2012, 2011 and 2010.

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 50 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, 2012 and 2011, we recorded asset retirement obligations of $10.5 million and $14.0 million. Additionally, we recorded $4.2 million and $5.4 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 facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities 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 2012, we recorded a pre-tax noncash impairment loss of $5.3 million related to our gathering systems in Kentucky. In fiscal 2011, we recorded pre-tax noncash impairment losses of $19.3 million related to our Fort Necessity storage project and $11.0 million related to our gathering systems in Kentucky. See Note 5 for further details.

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, 2012 and 2011, 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 an individual investment by investment 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 investment is written down to its estimated fair value.

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk in our natural gas distribution and nonregulated segments and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses and 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 on our natural gas distribution segment as a result of the use of financial instruments.

In our nonregulated segment, we have designated most of the natural gas inventory held by this operating segment 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.

Additionally, we have elected to treat fixed-price forward contracts used in our nonregulated segment 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.

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 is referred to as timing ineffectiveness. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Our nonregulated segment also utilizes 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. As of September 30, 2012 and 2011, the Company netted $23.7 million and $28.8 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We manage interest rate risk, typically when we plan to issue new long-term debt or to refinance existing long-term debt. Prior to fiscal 2012, 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 cash flow hedges 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.

During fiscal 2012, we began using interest rate swaps to mitigate interest rate risk. We entered into an interest rate swap associated with our $260 million short-term financing facility through December 27, 2012. Due to the short-term nature of the swap and the related financing facility, we did not designate the interest rate swap as a hedge. Gains and losses associated with the swap are reported as a component of interest expense.

Additionally, in October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, which we designated as cash flow hedges at the time the agreements were executed. Unrealized gains and losses associated with the forward starting interest rate swaps will be recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred will be reported as a component of interest expense.

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 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. 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 — Represents 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. The Level 1 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents 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 and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 — Represents 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. As of September 30, 2012 our Master Trust owned one real estate investment that qualifies as a Level 3 fair value measurement. Currently, we have no other 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. Our measurement date is 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 obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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.

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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, 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, 2012 and 2011, consisted of the following unrealized gains (losses):

	September 30	
	2012	2011
	(In thousands)	
Unrealized holding gains on investments	$ 5,661	$ 2,558
Treasury lock agreements	(44,273)	(34,157)
Cash flow hedges	(8,995)	(16,861)
	$(47,607)	$(48,460)

Contingencies — In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties or the action of various regulatory agencies. For such matters, we record liabilities when they are considered probable and reasonably estimable, based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Subsequent events — We have evaluated subsequent events from the September 30, 2012 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. Except as disclosed in Note 4, no events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — During the year ended September 30, 2012, three new accounting standards were announced that will become applicable to the Company in future periods. The first standard requires enhanced disclosure of offsetting arrangements for financial instruments and will become effective for annual periods beginning after January 1, 2013 and for interim periods within those annual periods. The second standard indefinitely defers the effective date for new presentation requirements related to reclassifications of items from accumulated other comprehensive income, which were scheduled to be effective for interim and annual periods beginning after December 15, 2011. The third standard allows companies to apply qualitative impairment tests to indefinite-lived intangibles if certain criteria are met and is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. The adoption of these standards should not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the year ended September 30, 2012.

3. Goodwill

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2012:

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
		(In thousands)		
Balance as of September 30, 2011	$572,908	$132,381	$34,711	$740,000
Deferred tax adjustments on prior acquisitions[1]	642	41	—	683
Balance as of September 30, 2012	$573,550	$132,422	$34,711	$740,683

(1) During the preparation of the fiscal 2012 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 $0.7 million.

4. Financial Instruments

We use financial instruments to mitigate commodity price risk and 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 and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

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, 2012 and 2011:

	Natural Gas Distribution	Nonregulated	Total
		(In thousands)	
September 30, 2012[3]			
Assets from risk management activities, current[1]	$ 6,934	$ 17,773	$ 24,707
Assets from risk management activities, noncurrent	2,283	—	2,283
Liabilities from risk management activities, current[1]	(85,366)	(15)	(85,381)
Liabilities from risk management activities, noncurrent	—	(9,206)	(9,206)
Net assets (liabilities)	$(76,149)	$ 8,552	$(67,597)
September 30, 2011[4]			
Assets from risk management activities, current[2]	$ 843	$ 17,501	$ 18,344
Assets from risk management activities, noncurrent	998	—	998
Liabilities from risk management activities, current[2]	(11,916)	(3,537)	(15,453)
Liabilities from risk management activities, noncurrent	(67,862)	(10,227)	(78,089)
Net assets (liabilities)	$(77,937)	$ 3,737	$(74,200)

(1) Includes $23.7 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $5.9 million was used to offset current risk management liabilities under master netting arrangements and the remaining $17.8 million is classified as current risk management assets.

(2) Includes $28.8 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

(3) The September 30, 2012 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Georgia operations. At September 30, 2012, assets and liabilities held for sale included $0.1 million of current assets from risk management activities and $0.3 million of current liabilities from risk management activities.

(4) The September 30, 2011 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations. At September 30, 2011, assets and liabilities held for sale included $1.3 million of current liabilities from risk management activities.

Regulated Commodity Risk Management Activities

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2011-2012 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $4.78 per Mcf. We have not designated these financial instruments as hedges.

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. To provide these services, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request. In an effort to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity, AEH sells financial instruments to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 63 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

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

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

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2012, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.4 Bcf.

Interest Rate Risk Management Activities

We have periodically managed interest rate risk by entering into financial instruments to fix the Treasury yield component of the interest cost associated with anticipated financings. Prior to fiscal 2012, we used Treasury locks to mitigate interest rate risk; however, in the fourth quarter of fiscal 2012 we started utilizing interest rate swaps and forward starting interest rate swaps to manage this risk.

In August 2012, we redeemed $250 million of senior notes originally maturing on January 15, 2013 through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds received from the issuance of $350 million 30-year unsecured notes anticipated to occur in January 2013. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

In the fourth quarter of fiscal 2012 we entered into an interest rate swap to fix the LIBOR component of our $260 million short-term financing facility through December 27, 2012. Due to the short-term nature of the swap and the related financing facility we did not designate the interest rate swap as a hedge. Gains and losses associated with the swap are reported as a component of interest expense.

In October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, which we designated as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the forward starting interest rate swaps will be recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred will be reported as a component of interest expense.

In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $300 million of a total $400 million of senior notes that were issued in June 2011. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and is being recognized as a component of interest expense over the 30-year life of the senior notes.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pre-tax cash gain of $27.8 million during the second quarter of fiscal 2011.

In prior years, we entered into several Treasury lock agreements to fix the Treasury yield component of the interest cost of financing for various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extends through fiscal 2041.

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, 2012, 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, 2012, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(22,650)
	Cash Flow	—	35,300
	Not designated	24,185	49,155
		24,185	61,805

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, 2012 and 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $23.7 million and $28.8 million of cash held on deposit in margin accounts as of September 30, 2012 and 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our 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	Nonregulated	Total
			(In thousands)	
September 30, 2012				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 19,301	$ 19,301
Noncurrent commodity contracts	Deferred charges and other assets	—	1,923	1,923
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(85,040)	(23,787)	(108,827)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(4,999)	(4,999)
Total		(85,040)	(7,562)	(92,602)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets[1]	7,082	98,393	105,475
Noncurrent commodity contracts	Deferred charges and other assets	2,283	60,932	63,215
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[2]	(585)	(99,824)	(100,409)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(67,062)	(67,062)
Total		8,780	(7,561)	1,219
Total Financial Instruments		$(76,260)	$(15,123)	$ (91,383)

(1) Other current assets not designated as hedges in our natural gas distribution segment include $0.1 million related to risk management assets that were classified as assets held for sale at September 30, 2012.

(2) Other current liabilities not designated as hedges in our natural gas distribution segment include $0.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2012.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2011				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	—	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(31,064)	(31,064)
Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[1]	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$(79,277)	$(25,050)	$(104,327)

[1] Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the years ended September 30, 2012, 2011 and 2010, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $23.1 million, $24.8 million and $51.8 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our consolidated income statement for the years ended September 30, 2012, 2011 and 2010 is presented below.

	Fiscal Year Ended September 30		
	2012	2011	2010
		(In thousands)	
Commodity contracts	$30,266	$16,552	$34,650
Fair value adjustment for natural gas inventory designated as the hedged item	(5,797)	9,824	19,867
Total impact on purchased gas cost	$24,469	$26,376	$54,517
The impact on purchased gas cost is comprised of the following:			
Basis ineffectiveness	$ 1,170	$ 803	$ (1,272)
Timing ineffectiveness	23,299	25,573	55,789
	$24,469	$26,376	$54,517

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 purchased gas cost.

To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market. During the year ended September 30, 2012, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to market. We did not record a writedown for nonqualifying natural gas inventory for the years ended September 30, 2011 and 2010.

Cash Flow Hedges

The impact of cash flow hedges on our consolidated income statements for the years ended September 30, 2012, 2011 and 2010 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Fiscal Year Ended September 30, 2012			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
		(In thousands)		
Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts	$ —	$—	$(62,678)	$(62,678)
Loss arising from ineffective portion of commodity contracts	—	—	(1,369)	(1,369)
Total impact on purchased gas cost	—	—	(64,047)	(64,047)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,009)	—	—	(2,009)
Total impact from cash flow hedges	$(2,009)	$—	$(64,047)	$(66,056)

	Fiscal Year Ended September 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts	$ —	$ —	$(28,430)	$(28,430)
Loss arising from ineffective portion of commodity contracts	—	—	(1,585)	(1,585)
Total impact on purchased gas cost	—	—	(30,015)	(30,015)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,455)	—	—	(2,455)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total impact from cash flow hedges	$19,348	$6,000	$(30,015)	$ (4,667)

	Fiscal Year Ended September 30, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts	$ —	$—	$(44,809)	$(44,809)
Loss arising from ineffective portion of commodity contracts	—	—	(2,717)	(2,717)
Total impact on purchased gas cost	—	—	(47,526)	(47,526)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,678)	—	—	(2,678)
Total impact from cash flow hedges	$(2,678)	$—	$(47,526)	$(50,204)

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 years ended September 30, 2012 and 2011. 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	
	2012	2011
	(In thousands)	
Decrease in fair value:		
Treasury lock agreements	$(11,458)	$(12,720)
Forward commodity contracts	(30,366)	(12,096)
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	1,342	(15,969)
Forward commodity contracts	38,232	17,344
Total other comprehensive loss from hedging, net of tax[1]	$ (2,250)	$(23,441)

[1] Utilizing an income tax rate ranging from approximately 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2012. However, the table below does not include the expected recognition in earnings of the Treasury lock agreements entered into in August 2011 as those financial instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
2013	$ (1,276)	$(7,171)	$ (8,447)
2014	(1,276)	(1,908)	(3,184)
2015	606	10	616
2016	776	46	822
2017	675	28	703
Thereafter	10,222	—	10,222
Total[1]	$ 9,727	$(8,995)	$ 732

[1] Utilizing an income tax rate ranging from approximately 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our consolidated income statements for the years ended September 30, 2012, 2011 and 2010 was an increase (decrease) in revenue of $(2.5) million, $(1.4) million and $15.4 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

5. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The fair value of these assets is presented in Note 9.

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 tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2012 and 2011. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[2]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2012
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 9,365	$ —	$ —	$ 9,365
Nonregulated segment[1]	714	179,835	—	(162,776)	17,773
Total financial instruments	714	189,200	—	(162,776)	27,138
Hedged portion of gas stored underground	67,192	—	—	—	67,192
Available-for-sale securities					
Money market funds	—	1,634	—	—	1,634
Registered investment companies	40,212	—	—	—	40,212
Bonds	—	22,552	—	—	22,552
Total available-for-sale securities	40,212	24,186	—	—	64,398
Total assets	$108,118	$213,386	$ —	$(162,776)	$158,728
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 85,625	$ —	$ —	$ 85,625
Nonregulated segment[1]	4,563	191,109	—	(186,451)	9,221
Total liabilities	$ 4,563	$276,734	$ —	$(186,451)	$ 94,846

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(2)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(4)	September 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,841	$ —	$ —	$ 1,841
Nonregulated segment(1)	8,502	104,156	—	(95,156)	17,502
Total financial instruments	8,502	105,997	—	(95,156)	19,343
Hedged portion of gas stored underground	47,940	—	—	—	47,940
Available-for-sale securities					
Money market funds	—	1,823	—	—	1,823
Registered investment companies	36,444	—	—	—	36,444
Bonds	—	14,366	—	—	14,366
Total available-for-sale securities	36,444	16,189	—	—	52,633
Total assets	$92,886	$122,186	$ —	$ (95,156)	$119,916
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 81,118	$ —	$ —	$ 81,118
Nonregulated segment(1)	9,324	128,384	—	(123,943)	13,765
Total liabilities	$ 9,324	$209,502	$ —	$(123,943)	$ 94,883

(1) Certain of the nonregulated segment's financial instruments were reclassified from Level 1 to Level 2 upon further evaluation.

(2) Our Level 2 measurements consist of over-the-counter options and swaps, which are valued using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences, municipal and corporate bonds, which are valued based on the most recent available quoted market prices and money market funds which are valued at cost.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2012 we had $23.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $5.9 million was used to offset current risk management liabilities under master netting agreements and the remaining $17.8 million is classified as current risk management assets.

(4) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting agreements and the remaining $16.4 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
	(In thousands)			
As of September 30, 2012:				
Domestic equity mutual funds	$25,779	$8,183	$ —	$33,962
Foreign equity mutual funds	5,568	682	—	6,250
Bonds	22,358	196	(2)	22,552
Money market funds	1,634	—	—	1,634
	$55,339	$9,061	$ (2)	$64,398
As of September 30, 2011:				
Domestic equity mutual funds	$27,748	$4,074	$ —	$31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	—	—	1,823
	$48,558	$4,351	$(276)	$52,633

At September 30, 2012 and 2011, our available-for-sale securities included $41.8 million and $38.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans as discussed in Note 9. At September 30, 2012 we maintained investments in bonds that have contractual maturity dates ranging from October 2012 through July 2016.

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. 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.

Atmos Gathering Company (AGC) owns and operates the Park City and Shrewsbury gathering systems in Kentucky. The Park City gathering system consists of a 23-mile low pressure pipeline and a nitrogen removal unit that was constructed in 2008. The Shrewsbury production, gathering and processing assets were acquired in 2008 at which time we sold the production assets to a third party. As a result of the sale of the production assets, we obtained a 10-year production payment note under which we were to be paid from future production generated from the assets.

As discussed in Note 13, AGC is involved in an ongoing lawsuit with the Park City gathering system. Due to the lawsuit and a low natural gas price environment, the assets have generated operating losses. As a result of these developments, in fiscal 2011, we performed an impairment assessment of these assets and determined the assets to be impaired at which time we recorded a pre-tax noncash impairment loss of approximately $11 million. Due to developments in the fourth quarter of fiscal 2012, including further operating losses as a result of the lawsuit and management's decision to focus our nonregulated operations on delivered gas and transportation services, we performed an impairment assessment of these assets and determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value of approximately $0.5 million and recorded a pre-tax noncash impairment loss of approximately $5.3 million. We used a combination of a market and income approach in a weighted average discounted cash flow analysis that included significant inputs such as our weighted average cost of capital and assumptions regarding future natural gas prices. This is a Level 3 fair value measurement because the inputs used are unobservable. Based on this analysis, we determined the assets to be impaired.

In February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pre-tax noncash impairment loss to write off substantially all of our investment in the project.

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of September 30, 2012:

	September 30, 2012
	(In thousands)
Carrying Amount	$1,960,131
Fair Value	$2,426,434

6. Discontinued Operations

On August 1, 2012, we completed the sale of substantially all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $128 million, pursuant to an asset purchase agreement executed on May 12, 2011. In connection with the sale, we recognized a pre-tax gain of approximately $9.9 million.

On August 8, 2012, we entered into a definitive agreement to sell substantially all of our natural gas distribution assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $141 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals, which we currently anticipate will occur in late fiscal 2013.

As required under generally accepted accounting principles, the operating results of our Georgia, Missouri, Illinois and Iowa operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations.

The following table presents statement of income data related to discontinued operations in our Georgia, Missouri, Illinois and Iowa service areas.

	Year Ended September 30		
	2012	2011	2010
		(In thousands)	
Operating revenues	$114,703	$141,227	$128,630
Purchased gas cost	62,902	83,537	77,825
Gross profit	51,801	57,690	50,805
Operating expenses	24,174	27,362	25,202
Operating income	27,627	30,328	25,603
Other nonoperating income (expense)	611	57	(31)
Income from discontinued operations before income taxes	28,238	30,385	25,572
Income tax expense	10,066	12,372	9,584
Income from discontinued operations	18,172	18,013	15,988
Gain on sale of discontinued operations, net of tax	6,349	—	—
Net income from discontinued operations	$ 24,521	$ 18,013	$ 15,988

The following table presents balance sheet data related to assets held for sale. At September 30, 2012 assets held for sale include assets and liabilities associated with our Georgia operations. At September 30, 2011 assets held for sale include assets and liabilities associated with our Missouri, Iowa and Illinois operations. On August 1, 2012 we completed the sale of our Missouri, Iowa and Illinois operations.

	September 30, 2012	September 30, 2011
	(In thousands)	
Net plant, property & equipment	$142,865	$127,577
Gas stored underground	4,688	11,931
Other current assets	6,931	786
Deferred charges and other assets	87	277
Assets held for sale	$154,571	$140,571
Accounts payable and accrued liabilities	$ 2,114	$ 1,917
Other current liabilities	3,776	4,877
Regulatory cost of removal	3,257	10,498
Deferred credits and other liabilities	2,426	1,153
Liabilities held for sale	$ 11,573	$ 18,445

7. Debt

Long-term debt

Long-term debt at September 30, 2012 and 2011 consisted of the following:

	2012	2011
	(In thousands)	
Unsecured 10% Notes, redeemed December 2011	$ —	$ 2,303
Unsecured 5.125% Senior Notes, redeemed August 2012	—	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Medium term notes		
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term notes due in installments through 2013	131	262
Total long-term debt	1,960,131	2,212,565
Less:		
Original issue discount on unsecured senior notes and debentures	(3,695)	(4,014)
Current maturities	(131)	(2,434)
	$1,956,305	$2,206,117

Our unsecured 10% notes were paid on their maturity date on December 31, 2011 and were not replaced. Our Unsecured 5.125% Senior Notes were scheduled to mature in January 2013. On August 28, 2012 we redeemed these notes with proceeds received through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility that expires February 1, 2013 to repay the commercial paper borrowings utilized to redeem the notes. The short-term facility is expected to be repaid with the proceeds received through the issuance of $350 million 30-year unsecured senior notes, which are expected to be issued in January 2013. In connection with the redemption, we paid a $4.6 million make-whole premium in accordance with the terms of the indenture and the Senior Notes and accrued interest at the time of redemption. In accordance with regulatory requirements, the premium will be deferred and will be recognized over the life of the new unsecured senior notes expected to be issued in January 2013.

Short-term debt

Our short-term debt is utilized to fund ongoing working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity and capital expenditures. Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

Prior to the fourth quarter of fiscal 2012, we financed our short-term borrowing requirements through a combination of a $750 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $985 million of working capital funding. On July 25, 2012, we increased the borrowing capacity of our $10 million revolving credit facility to $14 million. As a result of these changes, we have $989 million of working capital funding at September 30, 2012. At September 30, 2012 and 2011, there was $310.9 million and $206.4 million outstanding under our commercial paper program. As of September 30, 2012 our commercial paper had maturities of approximately two months with interest rates of

0.43 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $789 million of working capital funding. The first facility is a five-year $750 million unsecured facility, expiring May 2016, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to two percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. This facility has an accordion feature which, if utilized, would increase borrowing capacity to $1.0 billion. At September 30, 2012, there were no borrowings under this facility, but we had $310.9 million of commercial paper outstanding leaving $439.1 million available.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At September 30, 2012, there were no borrowings outstanding under this facility.

The third facility is a $14 million committed revolving credit facility used primarily to issue letters of credit that bears interest at a LIBOR-based rate plus 1.5 percent. The borrowing capacity of this facility was increased from $10 million on July 25, 2012. At September 30, 2012, there were no borrowings outstanding under this credit facility; however, letters of credit totaling $11.5 million had been issued under the facility at September 30, 2012, which reduced the amount available by a corresponding amount.

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, 2012, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $500 million intercompany revolving credit facility with AEH. This facility replaced the former $350 million intercompany facility. This facility bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012. There was $211.5 million outstanding under this facility at September 30, 2012.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At September 30, 2012, there were no borrowings outstanding under this credit facility. However, at September 30, 2012, AEM letters of credit totaling $11.5 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 $138.5 million at September 30, 2012.

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, 2012, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.74 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at September 30, 2012, AEM's net working capital was $136.2 million and its tangible net worth was $150.8 million.

To supplement borrowings under this facility, AEH had a $350 million intercompany demand credit facility with AEC. This facility was replaced on January 1, 2012 with a $500 million intercompany facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2012. There were no borrowings outstanding under this facility at September 30, 2012.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. With the closing of the sale of our Missouri, Illinois and Iowa operations on August 1, 2012, there are no longer any restrictions on our ability to issue either debt or equity under the shelf until it expires on March 31, 2013, with $900 million available for issuance at September 30, 2012. We intend to file a new shelf registration statement with the SEC for at least $1.3 billion prior to the expiration of the current shelf.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

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

Further, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

We were in compliance with all of our debt covenants as of September 30, 2012. 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, 2012 were as follows (in thousands):

2013	$ 131
2014	—
2015	500,000
2016	—
2017	250,000
Thereafter	1,210,000
	$1,960,131

8. Stock and Other Compensation Plans

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans. We paid $100 million to Goldman Sachs & Co. on July 7, 2010 in a share forward transaction and received 2,958,580 shares of Atmos Energy common stock. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 our Board of Directors approved a program authorizing the repurchase of up to five million shares of common stock over a five-year period. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the Company. The program may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the Company deems appropriate. As of September 30, 2012, a total of 387,991 shares had been repurchased for an aggregate value of $12.5 million.

Stock-Based Compensation Plans

Total stock-based compensation expense was $19.2 million, $11.6 million and $12.7 million for the fiscal years ended September 30, 2012, 2011 and 2010, 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.

As of September 30, 2012, we were authorized to grant awards for up to a maximum of 8.7 million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2012, 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 1,949,088 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 units 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 fair value of the awards granted is based on the market price of our stock at the date of grant. The associated expense is recognized ratably over the vesting period.

Employees who are granted shares of time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate at which they are paid on shares of stock without restrictions. Time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in time-lapse restricted stock units.

Employees who are granted shares of performance-based restricted stock units under our LTIP have a forfeitable right to dividend equivalents that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividend equivalents on the performance-based restricted stock units are paid in the form of shares upon the vesting of the award. Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2012, 2011 and 2010:

	2012		2011		2010	
	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	1,264,142	$29.56	1,293,960	$27.28	1,295,841	$27.23
Granted	532,711	33.44	491,345	33.10	551,278	29.07
Vested	(494,308)	26.32	(464,321)	27.21	(493,957)	29.24
Forfeited	(39,963)	29.83	(56,842)	27.56	(59,202)	26.54
Nonvested at end of year	1,262,582	$32.46	1,264,142	$29.56	1,293,960	$27.28

As of September 30, 2012, there was $10.1 million of total unrecognized compensation cost related to non-vested time-lapse restricted shares and restricted stock units granted under the LTIP. That cost is expected to be recognized over a weighted-average period of 1.6 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2012, 2011 and 2010 was $13.0 million, $12.6 million and $14.4 million.

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2012		2011		2010	
	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	86,766	$22.16	434,962	$22.46	611,227	$21.88
Granted	—	—	—	—	—	—
Exercised	(76,672)	21.79	(348,196)	22.54	(176,265)	20.44
Forfeited	—	—	—	—	—	—
Expired	—	—	—	—	—	—
Outstanding at end of year[(1)]	10,094	$24.95	86,766	$22.16	434,962	$22.46
Exercisable at end of year[(2)]	10,094	$24.95	86,766	$22.16	434,962	$22.46

(1) The weighted-average remaining contractual life for outstanding options was 1.7 years, 1.7 years, and 1.6 years for fiscal years 2012, 2011 and 2010. The aggregate intrinsic value of outstanding options was $0.03 million, $0.3 million and $1.6 million for fiscal years 2012, 2011 and 2010.

(2) The weighted-average remaining contractual life for exercisable options was 1.7 years, 1.7 years and 1.6 years for fiscal years 2012, 2011 and 2010. The aggregate intrinsic value of exercisable options was $0.03 million, $0.3 million and $1.6 million for the fiscal years 2012, 2011 and 2010.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2012, 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
$21.23 to $22.99	2,164	0.4	$21.23
$23.00 to $25.95	7,930	2.1	$25.95
$21.23 to $25.95	10,094	1.7	$24.95

	Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Grant date weighted average fair value per share	$ —	$ —	$ —
Net cash proceeds from stock option exercises	$1,671	$7,848	$3,604
Income tax benefit from stock option exercises	$ 401	$1,010	$ 547
Total intrinsic value of options exercised	$ 256	$1,263	$ 239

As of September 30, 2012, 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 of Directors adopted the Outside Directors Stock-for-Fee Plan, which was approved by our shareholders in February 1995. 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.

In addition, we adopted an incentive plan in October 2001 to give the employees in our nonregulated segment an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure 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.

9. 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 that cover substantially all employees. These plans are discussed in further detail below.

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. 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, 2012				
Unrecognized transition obligation	$ —	$ —	$ 1,709	$ 1,709
Unrecognized prior service cost	(232)	—	(7,411)	(7,643)
Unrecognized actuarial loss	187,050	43,995	63,402	294,447
	$186,818	$43,995	$57,700	$288,513
September 30, 2011				
Unrecognized transition obligation	$ —	$ —	$ 3,220	$ 3,220
Unrecognized prior service cost	(373)	—	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$182,113	$30,654	$41,899	$254,666

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2012, 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 is 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. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan which was enhanced, effective January 1, 2011.

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 2012 and 2011, we contributed $46.5 million and $0.9 million in cash to the Plans to achieve a desired level of funding while maximizing the tax deductibility of this payment. In fiscal 2010, we did not make any contributions to our pension plans. Based upon market conditions subsequent to September 30, 2012, the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $30 million and $40 million to the Plans in fiscal 2013. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds.

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, 2012 and 2011.

		Actual Allocation September 30	
Security Class	**Targeted Allocation Range**	**2012**	**2011**
Domestic equities	35%-55%	42.6%	40.4%
International equities	10%-20%	13.9%	13.6%
Fixed income	10%-30%	18.6%	21.3%
Company stock	5%-15%	12.0%	13.5%
Other assets	5%-15%	12.9%	11.2%

At September 30, 2012 and 2011, the Plan held 1,169,700 shares of our common stock, which represented 12.0 percent and 13.5 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.6 million and $1.6 million during fiscal 2012 and 2011.

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. 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, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2012	2011	2012	2011	2010
Discount rate	4.04%	5.05%	5.05%	5.39%[(1)]	5.52%
Rate of compensation increase	3.50%	3.50%	3.50%	4.00%	4.00%
Expected return on plan assets	7.75%	7.75%	7.75%	8.25%	8.25%

(1) The discount rate for the Pension Account Plan increased from 5.39% to 5.68% effective January 1, 2011 due to a curtailment gain recorded in fiscal 2011.

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2012 and 2011:

	2012	2011
	(In thousands)	
Accumulated benefit obligation	$ 468,440	$ 414,489
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 429,432	$ 407,536
Service cost	15,084	14,384
Interest cost	21,568	22,264
Actuarial loss	46,197	12,944
Benefits paid	(24,553)	(27,534)
Divestitures	(7,697)	—
Curtailments	—	(162)
Benefit obligation at end of year	480,031	429,432
Change in plan assets:		
Fair value of plan assets at beginning of year	280,204	301,708
Actual return on plan assets	48,656	5,154
Employer contributions	46,534	876
Benefits paid	(24,553)	(27,534)
Divestitures	(7,697)	—
Fair value of plan assets at end of year	343,144	280,204
Reconciliation:		
Funded status	(136,887)	(149,228)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(136,887)	$(149,228)

Net periodic pension cost for the Plans for fiscal 2012, 2011 and 2010 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2012	2011	2010
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 15,084	$ 14,384	$ 13,499
Interest cost	21,568	22,264	20,870
Expected return on assets	(21,474)	(24,817)	(25,280)
Amortization of prior service cost	(141)	(429)	(960)
Recognized actuarial loss	14,451	9,498	9,290
Curtailment gain	—	(40)	—
Net periodic pension cost	$ 29,488	$ 20,860	$ 17,419

The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2012 and 2011. As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The methods used to determine fair value for the assets held by the Master Trust are fully described in Note 2. Assets at September 30, 2012 include $7.7 million that will be transferred to the purchaser of our Missouri, Illinois and Iowa operations during the first quarter of fiscal 2013. In addition to the assets shown below, the Master Trust had net accounts receivable of $0.5 million and $0.4 million at September 30, 2012 and 2011 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2012			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks — domestic equities	$114,799	$ —	$ —	$114,799
Money market funds	—	21,010	—	21,010
Registered investment companies:				
Domestic funds	19,984	—	—	19,984
International funds	36,714	—	—	36,714
Common/collective trusts — domestic funds	—	52,155	—	52,155
Government securities:				
Mortgage-backed securities	—	19,509	—	19,509
U.S. treasuries	7,597	487	—	8,084
Corporate bonds	—	35,960	—	35,960
Limited partnerships	140	41,786	—	41,926
Real estate	—	—	155	155
Total investments at fair value	$179,234	$170,907	$155	$350,296

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks — domestic equities	$ 94,336	$ —	$ —	$ 94,336
Money market funds	—	9,383	—	9,383
Registered investment companies:				
Domestic funds	12,921	—	—	12,921
International funds	27,528	—	—	27,528
Common/collective trusts — domestic funds	—	40,096	—	40,096
Government securities				
Mortgage-backed securities	—	18,860	—	18,860
U.S. treasuries	4,946	47	—	4,993
Corporate bonds	—	33,636	—	33,636
Limited partnerships	113	37,693	—	37,806
Real estate	—	—	200	200
Total investments at fair value	$139,844	$139,715	$200	$279,759

The fair value of our Level 3 real estate assets was determined based on independent third party appraisals. These assets decreased during the year ended September 30, 2012 due to the sale of a parcel of real estate during fiscal 2012.

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 (SERP) (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.

In August 2009, the Board of Directors determined that there would be no new participants in the SERP subsequent to August 5, 2009, except for any corporate officers who may be appointed to the Management Committee. The SERP is a defined benefit arrangement which provides a benefit equal to 60 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SERP. However, the Board also established a new defined benefit supplemental executive retirement plan (the 2009 SERP), effective August 5, 2009, with each participant being selected by the Board, with each such participant being either (i) a corporate officer (other than such officer who is appointed as a member of the Company's Management Committee), (ii) a division president or (iii) an employee selected in the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of service and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Account Plan (currently 4.69%).

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, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2012	2011	2012	2011	2010
Discount rate	4.04%	5.05%	5.05%	5.39%	5.52%
Rate of compensation increase	3.50%	3.50%	3.50%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2012 and 2011:

	2012	2011
	(In thousands)	
Accumulated benefit obligation	$ 121,815	$ 104,363
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 112,115	$ 108,919
Service cost	2,108	2,768
Interest cost	5,142	5,825
Actuarial loss	15,459	2,140
Benefits paid	(4,638)	(7,537)
Benefit obligation at end of year	130,186	112,115
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	4,638	7,537
Benefits paid	(4,638)	(7,537)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(130,186)	(112,115)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(130,186)	$(112,115)

Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2012 and 2011, assets held in the rabbi trusts consisted of available-for-sale securities of $41.8 million and $38.3 million, which are included in our fair value disclosures in Note 5.

Net periodic pension cost for the supplemental plans for fiscal 2012, 2011 and 2010 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2012	2011	2010
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$2,108	$ 2,768	$2,476
Interest cost	5,142	5,825	5,224
Amortization of transition asset	—	—	—
Amortization of prior service cost	—	—	187
Recognized actuarial loss	2,118	2,239	1,999
Net periodic pension cost	$9,368	$10,832	$9,886

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)	
2013	$ 38,800	$31,108
2014	35,551	13,453
2015	33,953	7,658
2016	33,536	4,680
2017	32,740	7,385
2018-2022	156,231	41,830

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 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 ERISA. 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 $28.3 million to our postretirement benefits plan during fiscal 2013.

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, 2012 and 2011.

	Actual Allocation September 30	
Security Class	2012	2011
Diversified investment funds	97.0%	96.8%
Cash and cash equivalents	3.0%	3.2%

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, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2011, 2010 and 2009. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2012	2011	2012	2011	2010
Discount rate	4.04%	5.05%	5.05%	5.39%	5.52%
Expected return on plan assets	4.70%	5.00%	5.00%	5.00%	5.00%
Initial trend rate	8.00%	8.00%	8.00%	8.00%	7.50%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2019	2018	2018	2016	2015

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2012 and 2011:

	2012	2011
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 263,694	$ 228,234
Service cost	16,353	14,403
Interest cost	13,861	12,813
Plan participants' contributions	3,649	2,892
Actuarial loss	28,815	17,966
Benefits paid	(13,197)	(13,046)
Subsidy payments	—	432
Divestitures	(4,860)	—
Benefit obligation at end of year	308,315	263,694
Change in plan assets:		
Fair value of plan assets at beginning of year	53,065	53,033
Actual return on plan assets	12,912	(1,500)
Employer contributions	22,139	11,254
Plan participants' contributions	3,649	2,892
Benefits paid	(13,197)	(13,046)
Subsidy payments	—	432
Divestitures	(1,496)	—
Fair value of plan assets at end of year	77,072	53,065
Reconciliation:		
Funded status	(231,243)	(210,629)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$(231,243)	$(210,629)

Net periodic postretirement cost for fiscal 2012, 2011 and 2010 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2012	2011	2010
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$16,353	$14,403	$13,439
Interest cost	13,861	12,813	12,071
Expected return on assets	(2,607)	(2,727)	(2,460)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	(1,450)	(1,450)	(1,450)
Recognized actuarial loss	2,648	347	374
Net periodic postretirement cost	$30,316	$24,897	$23,485

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:

	One-Percentage Point Increase	One-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 1,426	$ (1,287)
Effect on postretirement benefit obligation	$21,736	$(18,866)

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, our West Texas, Mid-Tex and Mississippi Divisions as well as our Kansas jurisdiction and Atmos Pipeline – Texas 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.

The following tables set forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2012 and 2011. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2. Assets at September 30, 2012 include $1.5 million that will be transferred to the purchaser of our Missouri, Illinois and Iowa operations during the first quarter of fiscal 2013.

	Assets at Fair Value as of September 30, 2012			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$2,360	$—	$ 2,360
Registered investment companies:				
Domestic funds	7,756	—	—	7,756
International funds	68,452	—	—	68,452
Total investments at fair value	$76,208	$2,360	$—	$78,568

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,707	$—	$ 1,707
Registered investment companies:				
Domestic funds	3,506	—	—	3,506
International funds	47,852	—	—	47,852
Total investments at fair value	$51,358	$1,707	$—	$53,065

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)		
2013	$ 28,317	$ 3,696	$—	$ 32,013
2014	15,174	4,487	—	19,661
2015	17,349	5,251	—	22,600
2016	19,221	6,128	—	25,349
2017	20,520	7,083	—	27,603
2018-2022	107,055	48,114	—	155,169

Defined Contribution Plans

As of September 30, 2012, 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 Holdings, LLC 401K Profit-Sharing Plan (the AEH 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. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees participate in our defined contribution plan, which was enhanced, effective January 1, 2011. Employees participating in the Pension Account Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into the Retirement Savings Plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

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 $10.5 million, $10.2 million, and $9.8 million for fiscal years 2012, 2011 and 2010. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code and applicable Treasury regulations. No discretionary contributions were made for fiscal years 2012, 2011 or 2010. At September 30, 2012 and 2011, the Retirement Savings Plan held 4.9 percent and 4.5 percent of our outstanding common stock.

The AEH 401K Profit-Sharing Plan covers substantially all AEH 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 75 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 four percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEH 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 AEH 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.2 million, $1.3 million and $1.3 million for fiscal years 2012, 2011 and 2010.

10. 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, 2012 and 2011:

	September 30	
	2012	2011
	(In thousands)	
Billed accounts receivable	$177,953	$216,145
Unbilled revenue	42,694	48,006
Other accounts receivable	23,304	16,592
Total accounts receivable	243,951	280,743
Less: allowance for doubtful accounts	(9,425)	(7,440)
Net accounts receivable	$234,526	$273,303

Other current assets

Other current assets as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Assets from risk management activities	$ 24,707	$ 18,344
Deferred gas costs	31,359	33,976
Taxes receivable	1,291	9,215
Current deferred tax asset	27,091	76,725
Prepaid expenses	17,114	22,499
Current portion of leased assets receivable	168	2,013
Materials and supplies	5,872	4,113
Assets held for sale	154,571	140,571
Other	10,609	9,015
Total	$272,782	$316,471

As discussed in Note 6, assets and liabilities related to our Georgia operations are classified as "assets held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2012. On August 1, 2012, we completed the divesture of our operations in Missouri, Illinois and Iowa. Assets and liabilities related to Missouri, Illinois and Iowa were classified as "assets held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2011.

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2012 and 2011:

	September 30	
	2012	2011
	(In thousands)	
Production plant	$ 5,020	$ 7,412
Storage plant	232,260	198,422
Transmission plant	1,185,007	1,126,509
Distribution plant	4,680,877	4,496,263
General plant	717,568	737,850
Intangible plant	39,626	41,096
	6,860,358	6,607,552
Construction in progress	274,112	209,242
	7,134,470	6,816,794
Less: accumulated depreciation and amortization	(1,658,866)	(1,668,876)
Net property, plant and equipment	$ 5,475,604	$ 5,147,918

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Marketable securities	$ 64,398	$ 52,633
Regulatory assets	334,551	278,920
Deferred financing costs	35,101	35,149
Assets from risk management activities	2,283	998
Other	14,929	16,093
Total	$451,262	$383,793

Other current liabilities

Other current liabilities as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Customer credit balances and deposits	$100,926	$106,743
Accrued employee costs	37,675	38,558
Deferred gas costs	23,072	8,130
Accrued interest	34,451	37,557
Liabilities from risk management activities	85,381	15,453
Taxes payable	64,319	57,853
Pension and postretirement obligations	39,625	33,036
Regulatory cost of removal accrual	78,525	35,078
Liabilities held for sale	11,573	18,445
Other	14,118	16,710
Total	$489,665	$367,563

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2012 and 2011 were comprised of the following accounts.

	September 30	
	2012	2011
	(In thousands)	
Postretirement obligations	$221,231	$202,709
Retirement plan obligations	235,965	236,227
Customer advances for construction	12,937	13,967
Regulatory liabilities	5,638	13,823
Asset retirement obligation	10,394	13,574
Liabilities from risk management activities	9,206	78,089
Other	12,555	6,306
Total	$507,926	$564,695

11. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities), we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, granted under the LTIP, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

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

	2012	2011	2010
	(In thousands, except per share data)		
Basic Earnings Per Share from continuing operations			
Income from continuing operations	$192,196	$189,588	$189,851
Less: Income from continuing operations allocated to participating securities	793	1,980	1,943
Income from continuing operations available to common shareholders	$191,403	$187,608	$187,908
Basic weighted average shares outstanding	90,150	90,201	91,852
Income from continuing operations per share — Basic	$ 2.12	$ 2.08	$ 2.05
Basic Earnings Per Share from discontinued operations			
Income from discontinued operations	$ 24,521	$ 18,013	$ 15,988
Less: Income from discontinued operations allocated to participating securities	101	188	164
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Basic weighted average shares outstanding	90,150	90,201	91,852
Income from discontinued operations per share — Basic	$ 0.27	$ 0.20	$ 0.17
Net income per share — Basic	$ 2.39	$ 2.28	$ 2.22
Diluted Earnings Per Share from continuing operations			
Income from continuing operations available to common shareholders	$191,403	$187,608	$187,908
Effect of dilutive stock options and other shares	4	4	5
Income from continuing operations available to common shareholders	$191,407	$187,612	$187,913
Basic weighted average shares outstanding	90,150	90,201	91,852
Additional dilutive stock options and other shares	1,022	451	570
Diluted weighted average shares outstanding	91,172	90,652	92,422
Income from continuing operations per share — Diluted	$ 2.10	$ 2.07	$ 2.03
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Effect of dilutive stock options and other shares	—	—	—
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Basic weighted average shares outstanding	90,150	90,201	91,852
Additional dilutive stock options and other shares	1,022	451	570
Diluted weighted average shares outstanding	91,172	90,652	92,422
Income from discontinued operations per share — Diluted	$ 0.27	$ 0.20	$ 0.17
Net income per share — Diluted	$ 2.37	$ 2.27	$ 2.20

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal years ended September 30, 2012, 2011 and 2010.

12. Income Taxes

The components of income tax expense from continuing operations for 2012, 2011 and 2010 were as follows:

	2012	2011	2010
		(In thousands)	
Current			
Federal	$ 631	$ (13,298)	$ (70,884)
State	6,888	6,841	6,849
Deferred			
Federal	103,971	107,950	172,690
State	(13,237)	5,498	10,831
Investment tax credits	(27)	(172)	(283)
	$ 98,226	$106,819	$119,203

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2012, 2011 and 2010 are set forth below:

	2012	2011	2010
		(In thousands)	
Tax at statutory rate of 35%	$101,648	$103,743	$108,169
Common stock dividends deductible for tax reporting	(2,096)	(1,930)	(1,785)
Penalties	66	2,292	104
Recognition (settlement) of uncertain tax positions	1,831	(4,950)	—
State taxes (net of federal benefit)	(5,958)	8,109	11,493
Other, net	2,735	(445)	1,222
Income tax expense	$ 98,226	$106,819	$119,203

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, 2012 and 2011 are presented below:

	2012	2011
	(In thousands)	
Deferred tax assets:		
Accruals not currently deductible for tax purposes	$ 7,906	$ 10,327
Customer advances	4,721	5,271
Nonqualified benefit plans	48,513	43,924
Postretirement benefits	62,802	62,274
Treasury lock agreements	25,448	20,060
Unamortized investment tax credit	14	120
Tax net operating loss and credit carryforwards	164,419	95,293
Difference between book and tax on mark to market accounting	2,342	8,039
Other, net	7,223	3,529
Total deferred tax assets	323,388	248,837
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,254,698)	(1,108,063)
Pension funding	(32,812)	(7,533)
Gas cost adjustments	(21,806)	(13,570)
Cost expensed for tax purposes and capitalized for book purposes	(2,065)	(3,039)
Total deferred tax liabilities	(1,311,381)	(1,132,205)
Net deferred tax liabilities	$ (987,993)	$ (883,368)
Deferred credits for rate regulated entities	$ 140	$ 325

At September 30, 2012, we had $10.1 million of federal alternative minimum tax credit carryforwards, $143.2 million of federal net operating loss carryforwards, $10.6 million of state net operating loss carryforwards and $0.5 million of state tax credits. The alternative minimum tax credit carryforwards do not expire. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2029. Depending on the jurisdiction in which the state net operating loss was generated, the state net operating loss carryforwards will begin to expire between 2016 and 2030. The state tax credits will begin to expire in 2018.

At September 30, 2012, we had recorded liabilities associated with uncertain tax positions totaling $1.8 million. The realization of these tax benefits would reduce our income tax expense by approximately $1.8 million.

Additionally, results for fiscal 2012 were favorably impacted by a state tax benefit of $13.6 million. Due to the completion of the sale of our Missouri, Iowa and Illinois service areas in the fiscal fourth quarter, the Company updated its analysis of the tax rate at which deferred taxes would reverse in the future to reflect the sale of these service areas. The updated analysis supported a reduction in the deferred tax rate which when applied to the balance of taxable income deferred to future periods resulted in a reduction of the Company's overall deferred tax liability.

At September 30, 2010, we had accrued liabilities associated with uncertain tax positions totaling $6.7 million. During the fiscal year ended September 30, 2011, the IRS completed its audit of fiscal years 2005-2007. All uncertain tax positions were effectively settled upon completion of the audit. As a result of the settlement, we reduced our unrecognized tax benefits by $6.7 million in the second quarter of fiscal 2011. Income tax expense was reduced by $5.0 million in the second quarter due to the realization of the tax positions which were previously uncertain.

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. We recognized a tax expense of $0.01 million, $0.01 million and $0.5 million related to penalty and interest expenses during the fiscal years ended September 30, 2012, 2011 and 2010.

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 2007.

13. Commitments and Contingencies

Litigation

Since April 2009, Atmos Energy and two subsidiaries of AEH, Atmos Energy Marketing, LLC (AEM) and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On October 17, 2011, we filed our brief of appellants with the Kentucky Court of Appeals (Court), appealing the verdict of the trial court. The appellees in this case subsequently filed their appellees' brief with the Court on January 16, 2012, with our reply brief being filed with the Court on March 19, 2012. Oral arguments were held in the case on August 27, 2012; however, the Court has yet to render a decision.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, *Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles*, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. On March 27, 2012 the court denied the motion to dismiss. Since that time, we have been engaged in discovery activities in this case.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We are a party to other litigation and 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, Tennessee and Keokuk, Iowa, 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. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa 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

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2012, AEH was committed to purchase 72.2 Bcf within one year, 29.0 Bcf within one to three years and 29.0 Bcf after three years under indexed contracts. AEH is committed to purchase 3.8 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $2.46 to $6.36 per Mcf. Purchases under these contracts totaled $978.8 million, $1,498.6 million and $1,562.8 million for 2012, 2011 and 2010.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of September 30, 2012 are as follows (in thousands):

2013	$259,235
2014	74,604
2015	—
2016	—
2017	—
Thereafter	—
	$333,839

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts as of September 30, 2012 are as follows (in thousands):

2013	$19,456
2014	10,554
2015	4,504
2016	278
2017	37
Thereafter	128
	$34,957

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.

The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities in our Mid-Tex Division agreed to a program of installing 100,000 replacements through September 30, 2012, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing 98,675 lines for a cost of $116.3 million as of September 30, 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

14. Leases

Capital and Operating Leases

We have entered into operating leases for office and warehouse space, vehicles and heavy equipment used in our operations. The remaining lease terms range from one to 21 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 and $1.3 million at September 30, 2012 and 2011. Accumulated depreciation for these capital leases totaled $0.9 and $0.9 million at September 30, 2012 and 2011. 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, 2012 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2013	$ 186	$ 17,571
2014	186	17,215
2015	186	15,940
2016	186	15,036
2017	186	14,597
Thereafter	78	100,632
Total minimum lease payments	1,008	$180,991
Less amount representing interest	286	
Present value of net minimum lease payments	$ 722	

Consolidated lease and rental expense amounted to $33.6 million, $35.5 million and $36.7 million for fiscal 2012, 2011 and 2010.

15. 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, 2012, 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. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2012 and 2011.

	September 30, 2012	September 30, 2011
Investment grade	60%	54%
Non-investment grade	40%	46%
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, 2012. 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]	Nonregulated Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$ 4	$ 4
Non-investment grade counterparties	—	—	—
	$—	$ 4	$ 4

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

16. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for fiscal 2012, 2011 and 2010 are presented below.

	2012	2011	2010
		(In thousands)	
Cash paid for interest	$150,606	$157,976	$161,925
Cash received for income taxes	$ (432)	$ (8,329)	$ (63,677)

There were no significant noncash investing and financing transactions during fiscal 2012, 2011 and 2010. All cash flows and noncash activities related to our commodity financial instruments are considered as operating activities.

17. 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 three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in nine 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 three segments:

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

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, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,144,376	$ 92,604	$1,201,503	$ —	$3,438,483
Intersegment revenues	954	154,747	149,800	(305,501)	—
	2,145,330	247,351	1,351,303	(305,501)	3,438,483
Purchased gas cost	1,122,587	—	1,296,179	(304,022)	2,114,744
Gross profit	1,022,743	247,351	55,124	(1,479)	1,323,739
Operating expenses					
Operation and maintenance	353,879	71,521	29,697	(1,484)	453,613
Depreciation and amortization	202,026	31,438	4,061	—	237,525
Taxes, other than income	162,377	15,568	3,128	—	181,073
Asset impairments	—	—	5,288	—	5,288
Total operating expenses	718,282	118,527	42,174	(1,484)	877,499
Operating income	304,461	128,824	12,950	5	446,240
Miscellaneous income (expense)	(12,657)	(1,051)	1,035	(1,971)	(14,644)
Interest charges	110,642	29,414	3,084	(1,966)	141,174
Income from continuing operations before income taxes	181,162	98,359	10,901	—	290,422
Income tax expense	57,314	35,300	5,612	—	98,226
Income from continuing operations	123,848	63,059	5,289	—	192,196
Income from discontinued operations, net of tax	18,172	—	—	—	18,172
Gain on sale of discontinued operations, net of tax	6,349	—	—	—	6,349
Net income	$ 148,369	$ 63,059	$ 5,289	$ —	$ 216,717
Capital expenditures	$ 546,818	$175,768	$ 10,272	$ —	$ 732,858

	Year Ended September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,469,781	$ 87,141	$1,729,513	$ —	$4,286,435
Intersegment revenues	883	132,232	295,380	(428,495)	—
	2,470,664	219,373	2,024,893	(428,495)	4,286,435
Purchased gas cost	1,452,721	—	1,959,893	(426,999)	2,985,615
Gross profit	1,017,943	219,373	65,000	(1,496)	1,300,820
Operating expenses					
Operation and maintenance	341,758	70,401	32,308	(1,502)	442,965
Depreciation and amortization	193,642	25,997	4,193	—	223,832
Taxes, other than income	160,455	14,700	2,612	—	177,767
Asset impairments	—	—	30,270	—	30,270
Total operating expenses	695,855	111,098	69,383	(1,502)	874,834
Operating income (loss)	322,088	108,275	(4,383)	6	425,986
Miscellaneous income	16,242	4,715	657	(430)	21,184
Interest charges	115,740	31,432	4,015	(424)	150,763
Income (loss) from continuing operations before income taxes	222,590	81,558	(7,741)	—	296,407
Income tax expense (benefit)	77,885	29,143	(209)	—	106,819
Income (loss) from continuing operations	144,705	52,415	(7,532)	—	189,588
Income from discontinued operations, net of tax	18,013	—	—	—	18,013
Net income (loss)	$ 162,718	$ 52,415	$ (7,532)	$ —	$ 207,601
Capital expenditures	$ 496,899	$118,452	$ 7,614	$ —	$ 622,965

	Year Ended September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,782,993	$ 97,023	$1,781,044	$ —	$4,661,060
Intersegment revenues	870	105,990	365,614	(472,474)	—
	2,783,863	203,013	2,146,658	(472,474)	4,661,060
Purchased gas cost	1,785,221	—	2,032,567	(470,864)	3,346,924
Gross profit	998,642	203,013	114,091	(1,610)	1,314,136
Operating expenses					
Operation and maintenance	349,465	72,249	34,517	(1,610)	454,621
Depreciation and amortization	182,097	21,368	5,074	—	208,539
Taxes, other than income	170,229	12,358	4,556	—	187,143
Total operating expenses	701,791	105,975	44,147	(1,610)	850,303
Operating income	296,851	97,038	69,944	—	463,833
Miscellaneous income (expense)	1,132	135	3,859	(5,717)	(591)
Interest charges	118,147	31,174	10,584	(5,717)	154,188
Income from continuing operations before income taxes	179,836	65,999	63,219	—	309,054
Income tax expense	69,875	24,513	24,815	—	119,203
Income from continuing operations	109,961	41,486	38,404	—	189,851
Income from discontinued operations, net of tax	15,988	—	—	—	15,988
Net income	$ 125,949	$ 41,486	$ 38,404	$ —	$ 205,839
Capital expenditures	$ 437,815	$ 95,835	$ 8,986	$ —	$ 542,636

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

	2012	2011	2010
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,351,479	$1,535,887	$1,751,186
Commercial	587,651	685,380	775,714
Industrial	71,960	96,636	101,814
Public authority and other	54,334	68,676	69,944
Total gas sales revenues	2,065,424	2,386,579	2,698,658
Transportation revenues	53,924	57,331	56,539
Other gas revenues	25,028	25,871	27,796
Total natural gas distribution revenues	2,144,376	2,469,781	2,782,993
Regulated transmission and storage revenues	92,604	87,141	97,023
Nonregulated revenues	1,201,503	1,729,513	1,781,044
Total operating revenues	$3,438,483	$4,286,435	$4,661,060

Balance sheet information at September 30, 2012 and 2011 by segment is presented in the following tables.

	September 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,432,017	$ 979,443	$ 64,144	$ —	$5,475,604
Investment in subsidiaries	747,496	—	(2,096)	(745,400)	—
Current assets					
Cash and cash equivalents	12,787	—	51,452	—	64,239
Assets from risk management activities	6,934	—	17,773	—	24,707
Other current assets	546,187	11,788	404,097	(223,056)	739,016
Intercompany receivables	636,557	—	—	(636,557)	—
Total current assets	1,202,465	11,788	473,322	(859,613)	827,962
Intangible assets	—	—	164	—	164
Goodwill	573,550	132,422	34,711	—	740,683
Noncurrent assets from risk management activities	2,283	—	—	—	2,283
Deferred charges and other assets	417,893	24,353	6,733	—	448,979
	$7,375,704	$1,148,006	$576,978	$(1,605,013)	$7,495,675
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,359,243	$ 328,161	$419,335	$ (747,496)	$2,359,243
Long-term debt	1,956,305	—	—	—	1,956,305
Total capitalization	4,315,548	328,161	419,335	(747,496)	4,315,548
Current liabilities					
Current maturities of long-term debt	—	—	131	—	131
Short-term debt	782,719	—	—	(211,790)	570,929
Liabilities from risk management activities	85,366	—	15	—	85,381
Other current liabilities	526,089	12,478	90,116	(9,170)	619,513
Intercompany payables	—	584,578	51,979	(636,557)	—
Total current liabilities	1,394,174	597,056	142,241	(857,517)	1,275,954
Deferred income taxes	789,288	220,647	5,148	—	1,015,083
Noncurrent liabilities from risk management activities	—	—	9,206	—	9,206
Regulatory cost of removal obligation	381,164	—	—	—	381,164
Deferred credits and other liabilities	495,530	2,142	1,048	—	498,720
	$7,375,704	$1,148,006	$576,978	$(1,605,013)	$7,495,675

	September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,248,198	$ 838,302	$ 61,418	$ —	$5,147,918
Investment in subsidiaries	670,993	—	(2,096)	(668,897)	—
Current assets					
Cash and cash equivalents	24,646	—	106,773	—	131,419
Assets from risk management activities	843	—	17,501	—	18,344
Other current assets	655,716	15,413	386,215	(196,154)	861,190
Intercompany receivables	569,898	—	—	(569,898)	—
Total current assets	1,251,103	15,413	510,489	(766,052)	1,010,953
Intangible assets	—	—	207	—	207
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	998	—	—	—	998
Deferred charges and other assets	353,960	18,028	10,807	—	382,795
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,255,421	$ 265,102	$405,891	$ (670,993)	$2,255,421
Long-term debt	2,205,986	—	131	—	2,206,117
Total capitalization	4,461,407	265,102	406,022	(670,993)	4,461,538
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	387,691	—	—	(181,295)	206,396
Liabilities from risk management activities	11,916	—	3,537	—	15,453
Other current liabilities	474,783	10,369	170,926	(12,763)	643,315
Intercompany payables	—	543,084	26,814	(569,898)	—
Total current liabilities	876,693	553,453	201,408	(763,956)	867,598
Deferred income taxes	789,649	173,351	(2,907)	—	960,093
Noncurrent liabilities from risk management activities	67,862	—	10,227	—	78,089
Regulatory cost of removal obligation	428,947	—	—	—	428,947
Deferred credits and other liabilities	473,602	12,218	786	—	486,606
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871

18. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. Prior-period amounts have been restated to reflect continuing operations. 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 2012:				
Operating revenues				
Natural gas distribution	$ 676,113[1]	$ 871,067[2]	$ 315,634[3]	$282,516
Regulated transmission and storage	56,759	58,037	67,073	65,482
Nonregulated	444,176	370,763	256,250	280,114
Intersegment eliminations	(93,054)	(74,358)	(62,543)	(75,546)
	1,083,994	1,225,509	576,414	552,566
Gross profit	355,392[1]	425,787[2]	293,171[3]	249,389
Operating income	139,471[1]	202,432[2]	81,546[3]	22,791
Income (loss) from continuing operations	62,384	102,084	28,014	(286)
Income from discontinued operations	6,123	7,027	3,118	1,904
Gain on sale of discontinued operations	—	—	—	6,349
Net income	68,507	109,111	31,132	7,967
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ —
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share — basic	$ 0.75	$ 1.20	$ 0.34	$ 0.09
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ —
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share — diluted	$ 0.75	$ 1.20	$ 0.34	$ 0.09

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2011:				
Operating revenues				
Natural gas distribution	$ 687,426[4]	$1,052,291[5]	$ 396,584[6]	$334,363[7]
Regulated transmission and storage	49,007	54,976	53,570	61,820
Nonregulated	475,640	583,531	491,285	474,437
Intersegment eliminations	(94,847)	(134,424)	(108,271)	(90,953)
	1,117,226	1,556,374	833,168	779,667
Gross profit	357,582[4]	444,466[5]	261,612[6]	237,160[7]
Operating income	150,773[4]	204,624[5]	31,394[6]	39,195[7]
Income (loss) from continuing operations	68,208	124,293	(3,150)	237
Income from discontinued operations	5,789	7,916	2,584	1,724
Net income (loss)	73,997	132,209	(566)	1,961
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.75	$ 1.36	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.06	0.09	$ 0.03	$ 0.02
Net income (loss) per share — basic	$ 0.81	$ 1.45	$ (0.01)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.75	$ 1.36	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.06	$ 0.09	$ 0.03	$ 0.02
Net income (loss) per share — diluted	$ 0.81	$ 1.45	$ (0.01)	$ 0.02

(1) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.2 million, $7.5 million and $4.9 million, which were not previously reported as discontinued operations.

(2) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.9 million, $8.5 million and $5.9 million, which were not previously reported as discontinued operations.

(3) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $9.4 million, $5.6 million and $3.2 million, which were not previously reported as discontinued operations.

(4) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $16.0 million, $7.1 million and $4.5 million, which were not previously reported as discontinued operations.

(5) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $25.1 million, $9.2 million and $6.6 million, which were not previously reported as discontinued operations.

(6) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $10.4 million, $5.2 million and $2.7 million, which were not previously reported as discontinued operations.

(7) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $9.6 million, $4.9 million and $2.1 million, which were not previously reported as discontinued operations.

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, 2012 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, 2012, 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/ KIM R. COCKLIN	/s/ BRET J. ECKERT
Kim R. Cocklin President and Chief Executive Officer	Bret J. Eckert Senior Vice President and Chief Financial Officer

November 12, 2012

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, 2012, 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, 2012, 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, 2012 and 2011, and the related statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2012 of Atmos Energy Corporation and our report dated November 12, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2012

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, 2012 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 13, 2013. Information regarding executive officers is reported below:

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2012, 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	65	15	Executive Chairman of the Board
Kim R. Cocklin	61	6	President and Chief Executive Officer
Louis P. Gregory	57	12	Senior Vice President and General Counsel
Michael E. Haefner	52	4	Senior Vice President, Human Resources
Bret J. Eckert	45	—	Senior Vice President and Chief Financial Officer

Robert W. Best was named Executive Chairman of the Board on October 1, 2010. From March 1997 through September 2008, Mr. Best served the Company as Chairman of the Board, President and Chief Executive Officer. From October 1, 2008 through September 30, 2010, Mr. Best continued to serve the Company as Chairman of the Board and Chief Executive Officer.

Kim R. Cocklin was named President and Chief Executive Officer effective October 1, 2010. Mr. Cocklin joined the Company in June 2006 and served as President and Chief Operating Officer of the Company from October 1, 2008 through September 30, 2010, after having served as Senior Vice President, Regulated Operations from October 2006 through September 2008. Mr. Cocklin was Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 through May 2006. Mr. Cocklin was appointed to the Board of Directors on November 10, 2009.

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.

Bret J. Eckert joined the Company in June 2012 as Senior Vice President, and on October 1, 2012 he was appointed Chief Financial Officer. Prior to joining the Company, Mr. Eckert was an Assurance Partner with Ernst & Young LLP where he developed extensive accounting and financial experience in the natural gas industry over his 22-year career.

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 13, 2013.

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 13, 2013.

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 13, 2013. 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 13, 2013.

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 13, 2013.

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 10.6(a) through 10.13(e) 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/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and Chief Financial Officer

Date: November 12, 2012

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Kim R. Cocklin and Bret J. Eckert, 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/ KIM R. COCKLIN Kim R. Cocklin	President, Chief Executive Officer and Director	November 12, 2012
/s/ BRET J. ECKERT Bret J. Eckert	Senior Vice President and Chief Financial Officer	November 12, 2012
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Vice President and Controller (Principal Accounting Officer)	November 12, 2012
/s/ ROBERT W. BEST Robert W. Best	Executive Chairman of the Board	November 12, 2012
/s/ RICHARD W. DOUGLAS Richard W. Douglas	Director	November 12, 2012
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 12, 2012
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 12, 2012
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 12, 2012
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 12, 2012
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 12, 2012
/s/ RICHARD A. SAMPSON Richard A. Sampson	Director	November 12, 2012
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 12, 2012
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 12, 2012
/s/ RICHARD WARE II Richard Ware II	Director	November 12, 2012

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2012

	Balance at beginning of period	Additions: Charged to cost & expenses	Additions: Charged to other accounts	Deductions	Balance at end of period
		(In thousands)			
2012					
Allowance for doubtful accounts	$ 7,440	$8,901	$—	$6,916[1]	$ 9,425
2011					
Allowance for doubtful accounts	$12,701	$2,201	$—	$7,462[1]	$ 7,440
2010					
Allowance for doubtful accounts	$11,478	$7,694	$—	$6,471[1]	$12,701

[1] Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession	
2.1(a)	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Midstates) Corp. as Buyer, dated as of May 12, 2011	Exhibit 2.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
2.1(b)	Amendment No. 1 to Asset Purchase Agreement	
2.2	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Georgia) Corp. as Buyer, dated as of August 8, 2012	Exhibit 2.1 to Form 8-K dated August 8, 2012 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation — Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation — Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 3, 2010)	Exhibit 3.2 of Form 8-K dated February 3, 2010 (File No. 1-10042)
	Instruments Defining Rights of Security Holders, Including Indentures	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	
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 6 3/4% 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 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(c)	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(d)	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(e)	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)
4.7(f)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 10, 2011 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Material Contracts	
10.1	Term Loan Credit Agreement, dated as of September 27, 2012 among Atmos Energy Corporation, the lenders from time to time party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, U.S. Bank National Association, as Syndication Agent and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Documentation Agent	Exhibit 10.1 to Form 8-K dated September 27, 2012 (File No. 1-10042)
10.2	Revolving Credit Agreement, dated as of May 2, 2011 among Atmos Energy Corporation, the Lenders from time to time parties thereto, The Royal Bank of Scotland plc as Administrative Agent, Crédit Agricole Corporate and Investment Bank as Syndication Agent, Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A. as Co-Documentation Agents	Exhibit 10.1 to Form 8-K dated May 2, 2011 (File No. 1-10042)
10.3(a)	Fifth Amended and Restated Credit Agreement, dated as of December 8, 2010, among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank, a swing line bank and a bank; Société Générale as co-syndication agent, an issuing bank and a bank and The Royal Bank of Scotland plc, as co-syndication agent and a bank; and Natixis, New York Branch, Crédit Agricole Corporate and Investment Bank, and Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A. as co-documentation agents and the other financial institutions that become parties thereto	Exhibit 10.1 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.3(b)	Third Amended and Restated Intercreditor Agreement, dated as of December 8, 2010, (as amended, supplemented and otherwise modified from time to time, the "Agreement"), among BNP Paribas, a bank organized under the laws of France, in its capacity as Collateral Agent (together with its successors and assigns in such capacity, the "Agent") for the Banks thereinafter referred to, and each bank and other financial institution which is now or hereafter a party to the Agreement in its capacity as a Bank and, as applicable, as a Swap Bank (collectively, the "Swap Banks") and/or a Physical Trade Bank (collectively, the "Physical Trade Banks")	Exhibit 10.2 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.4(a)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Master Confirmation dated July 1, 2010	Exhibit 10.6(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.4(b)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Supplemental Confirmation dated July 1, 2010	Exhibit 10.6(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.5(a)	Guaranty of Algonquin Power & Utilities Corp. dated May 12, 2011	Exhibit 10.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
10.5(b)	Guaranty of Algonquin Power & Utilities Corp. dated August 8, 2012	Exhibit 10.1 to Form 8-K dated August 8, 2012 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.6(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.6(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.7(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)
10.7(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)
10.8(a)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	Exhibit 10.14 to Form 10-K for fiscal year ended September 30, 2011 (File No. 1-10042)
10.8(b)*	Amendment No 1 to the Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	
10.9(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)
10.9(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of November 12, 2009)	Exhibit 10.10(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(c)*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan, Effective Date August 5, 2009	Exhibit 10.10(c) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(d)*	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)
10.9(e)*	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)
10.10(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)
10.10(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)
10.10(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)
10.11*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2012	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2011 (File No. 1-10042)
10.12*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan, Amended and Restated as of October 1, 2009	Exhibit 10.13 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.13(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 10, 2011)	Exhibit 99.1 to Form S-8 dated October 28, 2011 (File No. 333-177593)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13(b)*	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)
10.13(c)*	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)
10.13(d)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.13(e)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
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, 2012
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
	Interactive Data File	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

* 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.

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, 2011

OR

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

For the transition period from to

Commission file number 1-10042

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

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

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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark 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 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, 2011, was $3,008,806,271.

As of November 14, 2011, the registrant had 90,364,061 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 8, 2012, 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
PAP	Pension Account Plan
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 439 of the 440 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.
SRF	Stable Rate Filing
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 three 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. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, we will operate in nine states. 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 principally 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 safely operating our regulated and nonregulated businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

We have continued to grow our earnings after giving effect to our acquisitions and have experienced more than 25 consecutive years of increasing dividends. 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.

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 three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and

- The *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

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 rate base, 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. See Note 6 in the consolidated financial statements for a complete description of the anticipated sale of our Illinois, Iowa and Missouri service areas. 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 adjustment 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 approximately 94 percent of residential and commercial margins 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, 2011 we had WNA for our residential and commercial meters in the following service areas for the following periods:

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

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.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically 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 2011 were Anadarko Energy Services, BP Energy Company, ConocoPhillips, 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 4.4 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2011 was on February 2, 2011, when sales to customers reached approximately 4.4 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 45 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 primarily by our Atmos Pipeline — Texas Division.

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.

Below, we briefly describe 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, 2011, we held 1,116 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 fiscal 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers (Settled Cities) that has allowed us, beginning in fiscal 2008, to update rates for customers in these cities through an annual rate review mechanism (RRM). 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. In June 2011, we reached an agreement with the City of Dallas to enter into the Dallas Annual Rate Review (DARR). This rate review provides for an annual rate review without the necessity of filing a general rate case. The first filing made under this mechanism will be in January 2012.

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.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 189 communities, some of which of the Missouri communities are located in our Atmos Energy Colorado-Kansas Division.

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 nonregulated 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 fiscal 2008 and its Amarillo and Lubbock service areas during fiscal 2009 to update rates for customers in these service areas through an RRM.

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	05/01/2011	$807,733	9.36%	11.80%
Atmos Pipeline — Texas — GRIP	Texas	08/01/2011	816,976	9.36%	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	10.25%
	Kansas	08/01/2010	144,583	(2)	(2)
Kentucky/Mid-States	Georgia	03/31/2010	96,330[3]	8.61%	10.70%
	Illinois	11/01/2000	24,564	9.18%	11.56%
	Iowa	03/01/2001	5,000	(2)	11.00%
	Kentucky	06/01/2010	208,702[4]	(2)	(2)
	Missouri	09/01/2010	66,459	(2)	(2)
	Tennessee	04/01/2009	190,100	8.24%	10.30%
	Virginia	11/23/2009	36,861	8.48%	9.50% - 10.50%
Louisiana	Trans LA	04/01/2011	93,260	8.37%	10.00% - 10.80%
	LGS	07/01/2011	273,775	8.56%	10.40%
Mid-Tex — Settled Cities	Texas	09/01/2011	1,389,187[5]	8.29%	9.70%
Mid-Tex — Dallas	Texas	06/22/2011	1,268,601[5]	8.45%	10.10%
Mid-Tex — Environs GRIP	Texas	06/27/2011	1,268,601[5]	8.60%	10.40%
Mississippi	Mississippi	04/05/2011	239,197	(2)	9.86%
West Texas	Amarillo	08/01/2011	(2)	(2)	9.60%
	Lubbock	09/09/2011	60,892	8.19%	9.60%
	West Texas	08/01/2011	146,039	8.19%	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider(6)	WNA	Performance-Based Rate Program(7)	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	50/50	Yes(8)	No	No	110,709
	Kansas	(2)	Yes	Yes	No	128,679
Kentucky/Mid-States	Georgia	52/48	No	Yes	Yes	63,897
	Illinois	67/33	No	No	No	22,778
	Iowa	57/43	No	No	No	4,334
	Kentucky	(2)	Yes	Yes	Yes	176,246
	Missouri	49/51	No	No	No	56,643
	Tennessee	52/48	Yes	Yes	Yes	133,634
	Virginia	51/49	Yes	Yes	No	23,310
Louisiana.	Trans LA	52/48	No	Yes	No	75,813
	LGS	52/48	No	Yes	No	277,838
Mid-Tex — Settled Cities	Texas	50/50	Yes	Yes	No	1,259,042
Mid-Tex — Dallas & Environs	Texas	51/49	Yes	Yes	No	314,760
Mississippi	Mississippi	50/50	No	Yes	No	266,074
West Texas	Amarillo	52/48	Yes	Yes	No	70,431
	Lubbock	52/48	Yes	Yes	No	73,748
	West Texas	52/48	Yes	Yes	No	155,255

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the most recent 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) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $36.1 million included in the October 2011 Pipeline Replacement Program (PRP) surcharge. A total of $36.1 million of the Georgia rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.56 percent and an authorized return on equity of 10.70 percent.

(4) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $24.0 million included in the October 2011 PRP surcharge. A total of $24.0 million of the Kentucky rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.74 percent and an authorized return on equity of 10.50 percent.

(5) The Mid-Tex Rate Base amounts for the Settled Cities and Dallas & Environs areas represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base.

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

(7) 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.

(8) The recovery of the gas portion of uncollectible accounts gas cost adjustment has been approved for a two-year pilot program.

Natural Gas Distribution Sales and Statistical Data - Continuing Operations

	Fiscal Year Ended September 30				
	2011	**2010**	**2009**	**2008**	**2007**
METERS IN SERVICE, end of year					
Residential	2,855,998	2,836,483	2,826,814	2,834,884	2,815,974
Commercial	261,220	253,339	256,384	259,154	262,260
Industrial	2,008	2,029	2,136	2,183	2,281
Public authority and other	10,212	10,178	9,211	9,197	19,143
Total meters	3,129,438	3,102,029	3,094,545	3,105,418	3,099,658
SALES VOLUMES — MMcf[(2)]					
Gas Sales Volumes					
Residential	161,012	185,143	154,475	157,816	161,493
Commercial	91,215	99,924	88,445	90,992	92,601
Industrial	18,757	18,714	18,242	21,352	22,479
Public authority and other	10,482	10,107	12,393	13,739	12,265
Total gas sales volumes	281,466	313,888	273,555	283,899	288,838
Transportation volumes	132,357	128,965	123,972	133,997	127,066
Total throughput	413,823	442,853	397,527	417,896	415,904
OPERATING REVENUES (000's)[(2)]					
Gas Sales Revenues					
Residential	$1,570,723	$1,784,051	$1,768,082	$2,068,040	$1,924,523
Commercial	698,366	787,433	807,109	1,044,768	941,827
Industrial	106,569	110,280	132,487	208,681	190,812
Public authority and other	69,176	70,402	88,972	137,585	114,087
Total gas sales revenues	2,444,834	2,752,166	2,796,650	3,459,074	3,171,249
Transportation revenues	60,430	59,381	56,961	57,405	56,814
Other gas revenues	26,599	31,091	31,185	35,183	35,448
Total operating revenues	$2,531,863	$2,842,638	$2,884,796	$3,551,662	$3,263,511

Natural Gas Distribution Sales and Statistical Data - Discontinued Operations

	Fiscal Year Ended September 30				
	2011	**2010**	**2009**	**2008**	**2007**
Meters in service, end of period	83,753	84,011	84,299	86,361	87,469
Sales volumes — MMcf					
Total gas sales volumes	8,461	8,740	8,562	8,777	8,489
Transportation volumes	6,190	6,900	6,719	7,086	8,043
Total throughput	14,651	15,640	15,281	15,863	16,532
Operating revenues (000's)	$80,028	$69,855	$99,969	$103,468	$95,254

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data - Other Consolidated Statistics

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
Inventory storage balance — Bcf	55.0	54.3	57.0	58.3	58.0
Heating degree days[1]					
Actual (weighted average)	2,733	2,780	2,713	2,820	2,879
Percent of normal	99%	102%	100%	100%	100%
Average transportation revenue per Mcf	$ 0.46	$ 0.46	$ 0.46	$ 0.43	$ 0.44
Average cost of gas per Mcf sold	$ 5.30	$ 5.77	$ 6.95	$ 9.05	$ 8.09
Employees	4,753	4,714	4,691	4,558	4,472

Natural Gas Distribution Sales and Statistical Data by Division

	Fiscal Year Ended September 30, 2011							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado-Kansas	Other[3]	Total
METERS IN SERVICE FROM CONTINUING OPERATIONS								
Residential	1,449,673	349,993	331,272	271,346	237,059	216,655	—	2,855,998
Commercial	123,993	43,875	22,379	24,773	25,617	20,583	—	261,220
Industrial	136	798	—	482	501	91	—	2,008
Public authority and other	—	2,423	—	2,833	2,897	2,059	—	10,212
Total meters	1,573,802	397,089	353,651	299,434	266,074	239,388	—	3,129,438
SALES VOLUMES FROM CONTINUING OPERATIONS — MMcf[2]								
Gas Sales Volumes								
Residential	77,075	22,273	13,939	16,280	14,077	17,368	—	161,012
Commercial	50,056	13,407	7,448	6,932	6,630	6,742	—	91,215
Industrial	3,105	5,626	—	4,108	5,823	95	—	18,757
Public authority and other	—	1,395	—	3,294	3,418	2,375	—	10,482
Total	130,236	42,701	21,387	30,614	29,948	26,580	—	281,466
Transportation volumes	46,594	38,801	5,893	24,162	5,237	11,670	—	132,357
Total throughput	176,830	81,502	27,280	54,776	35,185	38,250	—	413,823
OPERATING MARGIN FROM CONTINUING OPERATIONS (000's)[2]	$ 490,484	$152,293	$125,894	$ 99,353	$ 93,042	$ 83,298	$ —	$1,044,364
OPERATING EXPENSES FROM CONTINUING OPERATIONS (000's)[2]								
Operation and maintenance	$ 147,967	$ 58,315	$ 42,219	$ 35,908	$ 39,895	$ 31,684	$ (7,905)	$ 348,083
Depreciation and amortization	$ 95,798	$ 29,644	$ 24,460	$ 16,735	$ 13,188	$ 17,084	$ —	$ 196,909
Taxes, other than income	$ 102,515	$ 10,828	$ 8,773	$ 17,024	$ 13,621	$ 8,610	$ —	$ 161,371
OPERATING INCOME FROM CONTINUING OPERATIONS (000's)[2]	$ 144,204	$ 53,506	$ 50,442	$ 29,686	$ 26,338	$ 25,920	$ 7,905	$ 338,001
CONSOLIDATED CAPITAL EXPENDITURES (000's)	$ 220,032	$ 65,766	$ 41,489	$ 40,387	$ 37,115	$ 31,399	$ 60,711	$ 496,899
PROPERTY, PLANT AND EQUIPMENT, EXCLUDING ASSETS HELD FOR SALE (000's)	$1,965,351	$663,837	$431,773	$393,545	$308,891	$311,013	$173,788	$4,248,198
OTHER CONSOLIDATED STATISTICS								
Heating Degree Days[1]								
Actual	2,100	3,920	1,431	3,541	2,707	5,692	—	2,733
Percent of normal	100%	99%	94%	99%	101%	101%	—	99%
Miles of pipe	29,296	12,215	8,333	7,712	6,563	6,750	—	70,869
Employees	1,668	568	438	351	363	287	1,078	4,753

See footnotes following these tables.

	Fiscal Year Ended September 30, 2010							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado-Kansas	Other[3]	Total
METERS IN SERVICE FROM CONTINUING OPERATIONS								
Residential	1,429,287	350,238	331,784	271,418	237,304	216,452	—	2,836,483
Commercial	116,240	43,554	22,420	24,919	25,520	20,686	—	253,339
Industrial	145	801	—	484	513	86	—	2,029
Public authority and other	—	2,411	—	2,809	2,896	2,062	—	10,178
Total meters	1,545,672	397,004	354,204	299,630	266,233	239,286	—	3,102,029
SALES VOLUMES FROM CONTINUING OPERATIONS — MMcf[2]								
Gas Sales Volumes								
Residential	92,489	22,897	15,810	19,772	15,775	18,400	—	185,143
Commercial	55,916	13,948	7,821	7,892	7,209	7,138	—	99,924
Industrial	3,227	5,615	—	4,317	5,424	131	—	18,714
Public authority and other	—	1,422	—	3,482	3,103	2,100	—	10,107
Total	151,632	43,882	23,631	35,463	31,511	27,769	—	313,888
Transportation volumes	45,822	36,882	5,626	22,429	5,551	12,655	—	128,965
Total throughput	197,454	80,764	29,257	57,892	37,062	40,424	—	442,853
OPERATING MARGIN FROM CONTINUING OPERATIONS (000's)[2]	$ 475,852	$143,347	$123,344	$105,476	$ 94,203	$ 79,789	$ —	$1,022,011
OPERATING EXPENSES FROM CONTINUING OPERATIONS (000's)[2]								
Operation and maintenance	$ 145,166	$ 56,481	$ 43,604	$ 36,696	$ 41,542	$ 30,892	$ 976	$ 355,357
Depreciation and amortization	$ 89,411	$ 28,066	$ 22,986	$ 15,881	$ 12,621	$ 16,182	$ —	$ 185,147
Taxes, other than income	$ 106,620	$ 12,562	$ 10,995	$ 19,390	$ 13,599	$ 8,172	$ —	$ 171,338
OPERATING INCOME FROM CONTINUING OPERATIONS (000's)[2]	$ 134,655	$ 46,238	$ 45,759	$ 33,509	$ 26,441	$ 24,543	$ (976)	$ 310,169
CONSOLIDATED CAPITAL EXPENDITURES (000's)	$ 196,109	$ 62,808	$ 47,193	$ 39,387	$ 28,538	$ 29,792	$ 33,988	$ 437,815
CONSOLIDATED PROPERTY, PLANT AND EQUIPMENT (000's)	$1,761,087	$750,225	$413,189	$319,053	$284,195	$300,380	$130,983	$3,959,112
OTHER CONSOLIDATED STATISTICS								
Heating Degree Days[1]								
Actual	2,100	3,924	1,532	3,537	2,734	5,909	—	2,780
Percent of normal	103%	100%	96%	99%	102%	106%	—	102%
Miles of pipe	29,156	12,196	8,381	7,666	6,546	7,175	—	71,120
Employees	1,650	587	439	344	371	284	1,039	4,714

Natural Gas Distribution Sales and Statistical Data by Division - Discontinued Operations

	Fiscal Year Ended September 30, 2011			Fiscal Year Ended September 30, 2010		
	Kentucky/ Mid-States	Colorado-Kansas	Total	Kentucky/ Mid-States	Colorado-Kansas	Total
Meters in service, end of period	83,325	428	83,753	83,577	434	84,011
Sales volumes — MMcf						
Total gas sales volumes	7,963	498	8,461	8,251	489	8,740
Transportation volumes	6,190	—	6,190	6,900	—	6,900
Total throughput	14,153	498	14,651	15,151	489	15,640
Operating income (000's)	$13,395	$1,020	$14,415	$11,628	$657	$12,285

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 and lending arrangements 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. Rates are 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 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				
	2011	2010	2009	2008	2007
CUSTOMERS, end of year					
Industrial	71	65	68	62	65
Other	156	176	168	189	196
Total	227	241	236	251	261
PIPELINE TRANSPORTATION VOLUMES — MMcf[1]	620,904	634,885	706,132	782,876	699,006
OPERATING REVENUES (000's)[1]	$219,373	$203,013	$209,658	$195,917	$163,229
Employees, at year end	64	62	62	60	54

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

Nonregulated Segment Overview

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin. Certain of these arrangements are with regulatory affiliates, which have been approved by applicable state regulatory commissions.

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials) have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher natural gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Nonregulated Sales and Statistical Data

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
CUSTOMERS, end of year					
Industrial	697	652	631	624	677
Municipal	65	61	63	55	68
Other	362	339	321	312	281
Total	1,124	1,052	1,015	991	1,026
INVENTORY STORAGE BALANCE — Bcf	15.7	17.9	19.9	12.4	21.3
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[1]	446,903	420,203	441,081	457,952	423,895
OPERATING REVENUES (000's)[1]	$2,024,893	$2,146,658	$2,283,988	$4,117,299	$2,901,879

(1) Sales volumes 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 rate strategy focuses 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 73 percent of our gross margin. We also have accelerated recovery of capital for approximately 11 percent of our gross margin. Combined, we have rate structures with accelerated recovery of all or a portion of our expenditures for approximately 84 percent of our gross margin. Additionally, we have WNA mechanisms in eight states that serve to minimize the effects of weather on approximately 94 percent of our gross margin. Finally, we have the ability to recover the gas cost portion of bad debts for approximately 73 percent of our gross margin. These mechanisms work in tandem to provide substantial 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 and inclusion of other taxes in gas costs 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 Energy's operating areas, 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, 2011, 2010 and 2009 were derived from sales at rates set by or subject to approval by local or state authorities. Net operating income increases resulting from ratemaking activity totaling $72.4 million, $56.8 million and $54.4 million, became effective in fiscal 2011, 2010 and 2009 as summarized below:

	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
Rate Action	2011	2010	2009
		(In thousands)	
Rate case filings	$20,502	$23,663	$ 2,959
Infrastructure programs	15,033	18,989	12,049
Annual rate filing mechanisms	35,216	13,757	38,764
Other ratemaking activity	1,675	392	631
	$72,426	$56,801	$54,403

Additionally, the following ratemaking efforts were initiated during fiscal 2011 but had not been completed as of September 30, 2011:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	PRP[(1)(2)]	Georgia	$1,192
	PRP[(1)(3)]	Kentucky	2,529
Mississippi	Stable Rate Filing	Mississippi	5,303
West Texas & Lubbock Environs	Rate Case[(4)]	Railroad Commission of Texas (RRC)	545
			$9,569

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

(2) The Georgia Commission issued a final order on October 5, 2011 approving a $1.2 million increase to operating income.

(3) The Kentucky Commission approved an increase of $2.5 million effective October 1, 2011.

(4) On September 30, 2011 the Company and Commission Staff signed a settlement and submitted to the Commission for their approval.

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 safely deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase in Annual Operating Income (In thousands)	Effective Date
2011 Rate Case Filings:			
West Texas — Amarillo Environs	Texas	$ 78	07/26/2011
Atmos Pipeline — Texas	Texas	20,424	05/01/2011
Total 2011 Rate Case Filings		$20,502	
2010 Rate Case Filings:			
Kentucky/Mid-States	Missouri	$ 3,977	09/01/2010
Colorado-Kansas	Kansas	3,855	08/01/2010
Kentucky/Mid-States	Kentucky	6,636	06/01/2010
Kentucky/Mid-States	Georgia	2,935	03/31/2010
Mid-Tex	Texas(1)	2,963	01/26/2010
Colorado-Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$23,663	
2009 Rate Case Filings:			
Kentucky/Mid-States	Tennessee	$ 2,513	04/01/2009
West Texas	Texas	446	Various
Total 2009 Rate Case Filings		$ 2,959	

(1) In its final order, the RRC approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Operating income should increase $0.2 million, net of the GRIP 2008 rates that will be superseded. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

Infrastructure Programs

As discussed above in "Natural Gas Distribution Segment Overview," infrastructure programs such as GRIP allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2011, 2010 and 2009:

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2011 Infrastructure Programs:				
Atmos Pipeline — Texas	12/2010	$ 72,980	$12,605	07/26/2011
Mid-Tex/Environs	12/2010	107,840	576	06/27/2011
West Texas/Lubbock & WT Cities Environs	12/2010	17,677	343	06/01/2011
Kentucky/Mid-States-Kentucky [1]	09/2011	3,329	468	06/01/2011
Kentucky/Mid-States-Missouri[2]	09/2010	2,367	277	02/14/2011
Kentucky/Mid-States-Georgia[1]	09/2009	5,359	764	10/01/2010
Total 2011 Infrastructure Programs		$209,552	$15,033	
2010 Infrastructure Programs:				
Mid-Tex[3]	12/2009	$ 16,957	$ 2,983	09/01/2010
West Texas	12/2009	19,158	363	06/14/2010
Atmos Pipeline — Texas	12/2009	95,504	13,405	04/20/2010
Kentucky/Mid-States-Missouri[2]	06/2009	3,578	563	03/02/2010
Colorado-Kansas-Kansas[4]	08/2009	6,917	766	12/12/2009
Kentucky/Mid-States-Georgia[1]	09/2008	6,327	909	10/01/2009
Total 2010 Infrastructure Programs		$148,441	$18,989	
2009 Infrastructure Programs:				
Mid-Tex[5]	12/2008	$105,777	$ 2,732	09/09/2009
Atmos Pipeline — Texas	12/2008	51,308	6,342	04/28/2009
Mid-Tex[3]	12/2007	57,385	1,837	01/26/2009
Kentucky/Mid-States-Missouri[2]	03/2008	3,367	408	11/04/2008
Kentucky/Mid-States-Georgia[1]	09/2007	748	198	10/01/2008
West Texas[6]	2007/08	27,425	532	Various
Total 2009 Infrastructure Programs		$246,010	$12,049	

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

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

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

(6) 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 revenue is applicable to environs customers only.

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 the 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	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2010	$ 5,126	09/27/2011
Mid-Tex	Dallas	12/31/2010	1,084	09/27/2011
West Texas	Lubbock	12/31/2010	319	09/08/2011
West Texas	Amarillo	12/31/2010	(492)	08/01/2011
Louisiana	LGS	12/31/2010	4,109	07/01/2011
Mid-Tex	Dallas	12/31/2010	1,598	07/01/2011
Louisiana	TransLa	09/30/2010	350	04/01/2011
Mid-Tex	Settled Cities	12/31/2009	23,122	10/01/2010
Total 2011 Filings			$35,216	
2010 Filings:				
West Texas	Lubbock	12/31/2009	$ (902)	09/01/2010
West Texas	WT Cities	12/31/2009	700	08/15/2010
West Texas	Amarillo	12/31/2009	1,200	08/01/2010
Louisiana	LGS	12/31/2009	3,854	07/01/2010
Louisiana	TransLa	09/30/2009	1,733	04/01/2010
Mississippi	Mississippi	06/30/2009	3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$13,757	
2009 Filings:				
Mid-Tex	Settled Cities	12/31/2008	$ 1,979	08/01/2009
West Texas	WT Cities	12/31/2008	6,599	08/01/2009
Louisiana	LGS	12/31/2008	3,307	07/01/2009
Louisiana	TransLa	09/30/2008	611	04/01/2009
Mississippi	Mississippi	06/30/2008	—	N/A
Mid-Tex	Settled Cities	12/31/2007	21,800	11/08/2008
West Texas	WT Cities	12/31/2007	4,468	11/20/2008
Total 2009 Filings			$38,764	

In June 2011, we reached an agreement with the City of Dallas to enter into the DARR. This rate review provides for an annual rate review without the necessity of filing a general rate case. The first filing made under this mechanism will be in January 2012.

In August 2010, we reached an agreement to extend the RRM in our Mid-Tex Division for an additional two-year period beginning October 1, 2010; however, the Mid-Tex Division will be required to file a general system-wide rate case on or before June 1, 2013. This extension provides for an annual rate adjustment to reflect changes in the Mid-Tex Division's costs of service and additions to capital investment from year to year, without the necessity of filing a general rate case.

The settlement also allows us to expand our existing program to replace steel service lines in the Mid-Tex Division's natural gas delivery system. On October 13, 2010, the City of Dallas approved the recovery of the return, depreciation and taxes associated with the replacement of 100,000 steel service lines across the Mid-Tex Division by September 30, 2012. The RRM 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 440 incorporated cities served by the Mid-Tex Division, 439 of these cities are part of the RRM process.

The West Texas RRM was entered into in August 2008 as a result of a settlement with the West Texas Coalition of Cities. The Lubbock and Amarillo RRMs were entered into in the spring of 2009. The West Texas Coalition of Cities agreed to extend its RRM for one additional cycle as part of the settlement of this fiscal year's filing.

During fiscal 2011, the RRC's Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expense associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2011, 2010 and 2009:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income	Effective Date
			(In thousands)	
2011 Other Rate Activity:				
West Texas	Triangle	Special Contract	$ 641	07/01/2011
Colorado-Kansas	Kansas	Ad Valorem(1)	685	01/01/2011
Colorado-Kansas	Colorado	AMI(2)	349	12/01/2010
Total 2011 Other Rate Activity			$1,675	
2010 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem(1)	$ 392	01/05/2010
Total 2010 Other Rate Activity			$ 392	
2009 Other Rate Activity:				
Colorado-Kansas	Kansas	Tax Surcharge(3)	$ 631	02/01/2009
Total 2009 Other Rate Activity			$ 631	

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates.

(2) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of our Colorado service area.

(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.

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 the necessary and appropriate steps to comply with these regulations.

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.

Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services. The increased competition has reduced margins most notably on its high-volume accounts.

Employees

At September 30, 2011, we had 4,949 employees, consisting of 4,817 employees in our regulated operations and 132 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 during fiscal 2011, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any violations 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 few 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.

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 nonregulated segment because the commodity financial instruments markets could become unavailable to us. Our nonregulated segment depends primarily upon a committed 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 nonregulated 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 in the last few years, 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 improving current economic conditions, 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. Additionally, our industrial customers may seek alternative energy sources, which could result in lower sales volumes.

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. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of the health care benefits for our employees.

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 few 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. Also, our costs of providing such benefits are subject to the continuing recovery of these costs through rates.

In addition, the costs of providing health care benefits to our employees could significantly increase over the next five to ten years. Although the full effects of the Health Care Reform Act should not impact the Company until 2014, the future cost of compliance with the provisions of this legislation is difficult to measure at this time.

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 caused by market supply and demand dynamics 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, particularly in our nonregulated business segments, which could lead to volatility in our earnings.

Physical trading in our nonregulated business segments 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. 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. 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. 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 before the open positions can be closed.

Further, the timing of the recognition for financial accounting purposes of gains or losses resulting from changes in the fair value of derivative financial instruments designated as hedges usually does not match 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. Also, if the local physical markets in which we trade do not move consistently with the NYMEX futures market upon which most of our commodity derivative financial instruments are valued, we could experience increased volatility in the financial results of our nonregulated segment.

Our nonregulated segment manages margins and limits 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. Any significant 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 compared to historical norms for both short and long-term 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 they 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 rapid changes in the capital markets.

We may experience increased federal, state and local regulation of the safety of our operations.

We are committed to constantly monitoring and maintaining our pipeline and distribution system to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 76,000 miles of pipeline and distribution lines. The pipeline replacement programs currently underway in several of our divisions typify the preventive maintenance and continual renewal that we perform on our natural gas distribution system in the 12 states in which we currently operate. The safety and protection of the public, our customers and our employees is our top priority. However, due primarily to the recent unfortunate pipeline incident in California, we anticipate companies in the natural gas distribution business may be subjected to even greater federal, state and local oversight of the safety of their operations in the future. Although we believe these costs are ultimately recoverable through our rates, costs of complying with such increased regulations may have at least a short-term adverse impact on our operating costs and financial results.

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. 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 have been a number of new federal and state legislative and regulatory initiatives proposed 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. However, neither this bill nor a related bill in the U.S. Senate, the Clean Energy and Emissions Power Act was passed by Congress. The adoption of this type of 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 in the future 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 that may be adopted 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 nonregulated 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. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our natural gas distribution and regulated transmission and storage operations.

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 serve any growth in the number of our customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. In addition, although we should ultimately recover the cost of the expenditures through rates, we must make significant capital expenditures during the next fiscal year in executing our steel service line replacement program in the Mid-Tex Division. 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 operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services.

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, 2011, our natural gas distribution segment owned an aggregate of 70,869 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 5,861 miles of gas transmission and gathering lines and our nonregulated segment owned 105 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 at September 30, 2011:

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	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated 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	60,458,299	30,549,198	91,007,497	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 at September 30, 2011:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Natural Gas Distribution Segment[2]			
	Colorado-Kansas Division	4,243,909	108,039
	Kentucky/Mid-States Division	16,835,380	444,339
	Louisiana Division	2,643,192	161,473
	Mississippi Division	3,875,429	165,402
	West Texas Division	2,375,000	81,000
Total		29,972,910	960,253
Nonregulated Segment			
	Atmos Energy Marketing, LLC	8,026,869	250,937
	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total		9,700,869	318,444
Total Contracted Storage Capacity		39,673,779	1,278,697

(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.

(2) On October 1, 2011, our Mid-Tex Division signed a new storage contract with a maximum storage quantity of 500,000 MMBtu and maximum daily withdrawal quantity of 50,000 MMBtu.

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. The headquarters for our nonregulated operations are in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

ITEM 3. *Legal Proceedings.*

See Note 13 to the consolidated financial statements.

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 2011 and 2010 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:

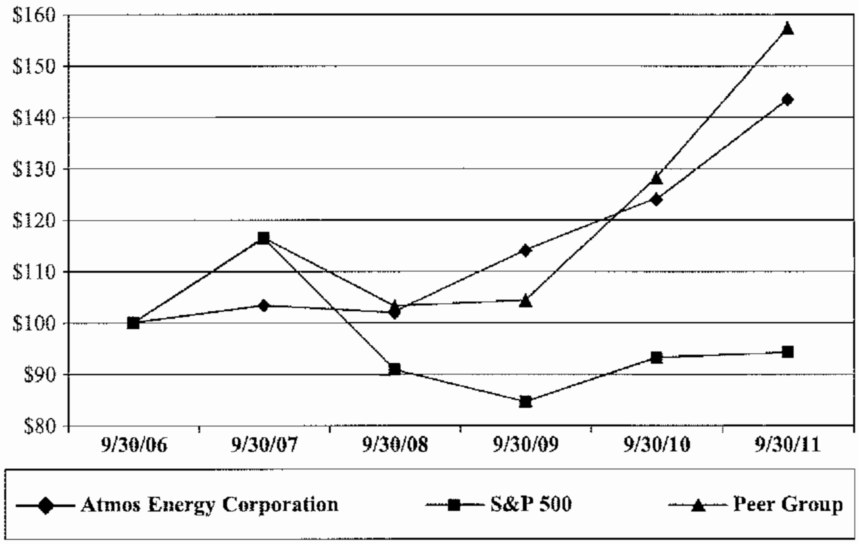
	Fiscal 2011			Fiscal 2010		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$31.72	$29.10	$.340	$30.06	$27.39	$.335
March 31	34.98	31.51	.340	29.52	26.52	.335
June 30	34.94	31.34	.340	29.98	26.41	.335
September 30	34.32	28.87	.340	29.81	26.82	.335
			$1.36			$1.34

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, 2011 was 18,746. 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 2011 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 a customized peer company group, the Comparison Company Index, 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, 2006 in our common stock, the S&P 500 Index and in the common stock of the companies in the Comparison Company Index, 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					
	9/30/06	9/30/07	9/30/08	9/30/09	9/30/10	9/30/11
Atmos Energy Corporation	100.00	103.36	101.92	113.82	123.97	143.45
S&P 500	100.00	116.44	90.85	84.58	93.17	94.24
Peer Group	100.00	116.52	103.24	104.34	128.20	157.38

The 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, 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 following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2011.

	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 . .	86,766	$22.16	319,700
Total equity compensation plans approved by security holders. . .	86,766	22.16	319,700
Equity compensation plans not approved by security holders. . .	—	—	—
Total	86,766	$22.16	319,700

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				
	2011[1]	2010	2009[1]	2008	2007 [1]
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$4,347,634	$4,719,835	$4,869,111	$7,117,837	$5,803,177
Gross profit	1,327,241	1,337,505	1,319,678	1,293,922	1,221,078
Operating expenses[1]	885,342	860,354	883,312	878,399	835,353
Operating income	441,899	477,151	436,366	415,523	385,725
Miscellaneous income (expense)	21,499	(156)	(3,067)	3,017	9,227
Interest charges	150,825	154,360	152,638	137,218	145,019
Income from continuing operations before income taxes	312,573	322,635	280,661	281,322	249,933
Income tax expense	113,689	124,362	97,362	107,837	89,105
Income from continuing operations	198,884	198,273	183,299	173,485	160,828
Income from discontinued operations, net of tax	8,717	7,566	7,679	6,846	7,664
Net income	$ 207,601	$ 205,839	$ 190,978	$ 180,331	$ 168,492
Weighted average diluted shares outstanding	90,652	92,422	91,620	89,941	87,486
Income per share from continuing operations — diluted	$ 2.17	$ 2.12	$ 1.98	$ 1.91	$ 1.82
Income per share from discontinued operations — diluted	0.10	0.08	0.09	0.08	0.09
Diluted net income per share	$ 2.27	$ 2.20	$ 2.07	$ 1.99	$ 1.91
Cash flows from operations	$ 582,844	$ 726,476	$ 919,233	$ 370,933	$ 547,095
Cash dividends paid per share	$ 1.36	$ 1.34	$ 1.32	$ 1.30	$ 1.28
Natural gas distribution throughput from continuing operations (MMcf)[2]	409,369	438,535	393,604	413,491	411,337
Natural gas distribution throughput from discontinued operations (MMcf)[2]	14,651	15,640	15,281	15,863	16,532
Total regulated transmission and storage transportation volumes (MMcf)[2]	435,012	428,599	528,689	595,542	505,493
Total nonregulated delivered gas sales volumes (MMcf)[2]	384,799	353,853	370,569	389,392	370,668
Financial Condition					
Net property, plant and equipment[5]	$5,147,918	$4,793,075	$4,439,103	$4,136,859	$3,836,836
Working capital[6]	143,355	(290,887)	91,519	78,017	149,217
Total assets	7,282,871	6,763,791	6,367,083	6,386,699	5,895,197
Short-term debt, inclusive of current maturities of long-term debt	208,830	486,231	72,681	351,327	154,430
Capitalization:					
Shareholders' equity	2,255,421	2,178,348	2,176,761	2,052,492	1,965,754
Long-term debt (excluding current maturities)	2,206,117	1,809,551	2,169,400	2,119,792	2,126,315
Total capitalization	4,461,538	3,987,899	4,346,161	4,172,284	4,092,069
Capital expenditures	622,965	542,636	509,494	472,273	392,435
Financial Ratios					
Capitalization ratio[3]	48.3%	48.7%	49.3%	45.4%	46.3%
Return on average shareholders' equity[4]	9.1%	9.1%	8.9%	8.8%	8.8%

(1) Financial results for fiscal years 2011, 2009 and 2007 include a $30.3 million, $5.4 million and a $6.3 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.

(5) Amount shown for fiscal 2011 are net of assets held for sale.

(6) Amount shown for fiscal 2011 includes assets held for sale.

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 adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

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 periodically. 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 nonregulated segments are recognized in the period in which actual volumes are transported and storage services are provided.

Operating revenues for our nonregulated 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 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.

Our nonregulated 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 which we seek to maximize the economic value associated with storage and transportation capacity we own or control in both our natural gas distribution and nonregulated businesses. 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 nonregulated segment, we have designated the natural gas inventory held by this operating segment 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 nonregulated 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 nonregulated 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 with Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designate these Treasury lock agreements as cash flow hedges at the time the agreements are executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements are recorded as a component of accumulated other comprehensive income (loss). The realized gain or loss recognized upon settlement of each Treasury lock agreement is 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. Hedge ineffectiveness, to the extent incurred, is reported as a component of interest expense.

Impairment assessments — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. As of September 30, 2011, 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 using a September 30 measurement date 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. 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 periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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.

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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 and 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 $1.9 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $0.8 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. Adverse developments in the global financial and credit markets in the last few years 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 further 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 62 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 fiscal 2011, we earned $207.6 million, or $2.27 per diluted share, which represents a one percent increase in net income and a three percent increase in diluted net income per share over fiscal 2010. During fiscal 2011, recent improvements in rate designs in our natural gas distribution segment and a successful regulatory outcome in our regulated transmission and storage segment offset a seven percent year-over-year decline in consolidated natural gas distribution throughput due to warmer weather and a 108 percent decrease in asset optimization margins as a result of weak natural gas market fundamentals. Results for fiscal 2011 were influenced by several non-recurring items, which increased diluted earnings per share by $0.03. The increase in fiscal 2011 earnings per share also reflects the favorable impact of our accelerated share buyback agreement initiated in the fourth quarter of fiscal 2010 and completed in the second quarter of fiscal 2011, which increased diluted earnings per share by $0.08.

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals. Due to the pending sales transaction, the results of operations for these three service areas are shown in discontinued operations.

On June 10, 2011 we issued $400 million of 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks associated with the offering. Substantially all of the net proceeds of approximately $394 million were used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

During the year ended September 30, 2011, we executed on our strategy to streamline our credit facilities, as follows:

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased in fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.
- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

After giving effect to these changes, we now have $985 million of liquidity available to us from our commercial paper program and four committed credit facilities and have reduced our financing costs. We believe this availability provides sufficient liquidity to fund our working capital needs.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2011, 2010 and 2009.

	For the Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Operating revenues	$4,347,634	$4,719,835	$4,869,111
Gross profit	1,327,241	1,337,505	1,319,678
Operating expenses	885,342	860,354	883,312
Operating income	441,899	477,151	436,366
Miscellaneous income (expense)	21,499	(156)	(3,067)
Interest charges	150,825	154,360	152,638
Income from continuing operations before income taxes	312,573	322,635	280,661
Income tax expense	113,689	124,362	97,362
Income from continuing operations	198,884	198,273	183,299
Income from discontinued operations, net of tax	8,717	7,566	7,679
Net income	$ 207,601	$ 205,839	$ 190,978
Diluted net income per share from continuing operations	$ 2.17	$ 2.12	$ 1.98
Diluted net income per share from discontinued operations	$ 0.10	$ 0.08	$ 0.09
Diluted net income per share	$ 2.27	$ 2.20	$ 2.07

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 104 percent, 81 percent and 83 percent to our consolidated net income for fiscal years 2011, 2010, and 2009. 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		
	2011	2010	2009
	(In thousands)		
Natural gas distribution segment	$162,718	$125,949	$116,807
Regulated transmission and storage segment	52,415	41,486	41,056
Nonregulated segment	(7,532)	38,404	33,115
Net income	$207,601	$205,839	$190,978

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		
	2011	2010	2009
	(In thousands, except per share data)		
Regulated operations	$215,133	$167,435	$157,863
Nonregulated operations	(7,532)	38,404	33,115
Consolidated net income	$207,601	$205,839	$190,978
Diluted EPS from regulated operations	$ 2.35	$ 1.79	$ 1.71
Diluted EPS from nonregulated operations	(0.08)	0.41	0.36
Consolidated diluted EPS	$ 2.27	$ 2.20	$ 2.07

We reported net income of $207.6 million, or $2.27 per diluted share for the year ended September 30, 2011, compared with net income of $205.8 million or $2.20 per diluted share in the prior year. Income from continuing operations was $198.9 million, or $2.17 per diluted share compared with $198.3 million, or $2.12 per diluted share in the prior-year period. Income from discontinued operations was $8.7 million or $0.10 per diluted share for the year, compared with $7.6 million or $0.08 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current year reduced net income by $6.6 million or $0.07 per diluted share compared with net losses recorded in the prior year of $4.3 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In the prior year, net income included the net positive impact of a state sales tax refund of $4.6 million, or $0.05 per diluted share. In the current year, net income includes the net positive impact of several one-time items totaling $3.2 million, or $0.03 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $30.3 million unfavorable impact related to the non-cash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

Net income during fiscal 2010 increased eight percent over fiscal 2009. Net income from our regulated operations increased six percent during fiscal 2010. The increase primarily reflects colder than normal weather in most of our service areas during fiscal 2010 as well as the net favorable impact of various ratemaking activities in our natural gas distribution segment. Net income in our nonregulated operations increased $5.3 million during fiscal 2010 primarily due to the impact of unrealized margins. Non-cash, net unrealized losses totaled $4.3 million which reduced earnings per share by $0.05 per diluted share in fiscal 2010 compared to fiscal 2009, when net unrealized losses totaled $21.6 million, which reduced earnings per share by $0.23 per diluted share.

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, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore the cost of gas typically does not have an impact on our gross profit as 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.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs 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. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 73 percent of our residential and commercial margins.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2011, 2010 and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands, unless otherwise noted)				
Gross profit	$1,044,364	$1,022,011	$997,604	$ 22,353	$24,407
Operating expenses	706,363	711,842	719,626	(5,479)	(7,784)
Operating income	338,001	310,169	277,978	27,832	32,191
Miscellaneous income	16,557	1,567	6,002	14,990	(4,435)
Interest charges	115,802	118,319	123,863	(2,517)	(5,544)
Income from continuing operations before income taxes	238,756	193,417	160,117	45,339	33,300
Income tax expense	84,755	75,034	50,989	9,721	24,045
Income from continuing operations	154,001	118,383	109,128	35,618	9,255
Income from discontinued operations, net of tax	8,717	7,566	7,679	1,151	(113)
Net Income	$ 162,718	$ 125,949	$116,807	$ 36,769	$ 9,142
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	281,466	313,888	273,555	(32,422)	40,333
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	127,903	124,647	120,049	3,256	4,598
Consolidated natural gas distribution throughput from continuing operations — MMcf	409,369	438,535	393,604	(29,166)	44,931
Consolidated natural gas distribution throughput from discontinued operations — MMcf	14,651	15,640	15,281	(989)	359
Total consolidated natural gas distribution throughput — MMcf	424,020	454,175	408,885	(30,155)	45,290
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.47	$ 0.47	$ —	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.30	$ 5.77	$ 6.95	$ (0.47)	$ (1.18)

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the fiscal years ended September 30, 2011, 2010 and 2009. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(In thousands)		
Mid-Tex	$144,204	$134,655	$127,625	$ 9,549	$ 7,030
Kentucky/Mid-States	53,506	46,238	37,683	7,268	8,555
Louisiana	50,442	45,759	43,434	4,683	2,325
West Texas	29,686	33,509	23,338	(3,823)	10,171
Mississippi	26,338	26,441	21,287	(103)	5,154
Colorado-Kansas	25,920	24,543	20,580	1,377	3,963
Other	7,905	(976)	4,031	8,881	(5,007)
Total	$338,001	$310,169	$277,978	$27,832	$32,191

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

The $22.4 million increase in natural gas distribution gross profit primarily reflects a $40.4 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Kentucky and Kansas service areas.

These increases were partially offset by:

- $12.0 million decrease due to a seven percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather this fiscal year compared to the same period last year in most of our service areas.
- $8.1 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $5.5 million, primarily due to the following:

- $10.0 million decrease in taxes, other than income, due to lower revenue-related taxes.
- $6.4 million decrease in employee-related expenses.

These decreases were partially offset by:

- $5.4 million increase due to the absence of a state sales tax reimbursement received in the prior year.
- $11.8 million increase in depreciation and amortization expense.
- $1.8 million increase in vehicles and equipment expense.

Net income for this segment for the year-to-date period was also favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $24.4 million increase in natural gas distribution gross profit primarily reflects rate adjustments and increased throughput as follows:

- $33.4 million net increase in rate adjustments, primarily in the West Texas, Mid-Tex, Louisiana, Kentucky, Tennessee, Virginia and Mississippi service areas.

- $10.6 million increase as a result of an 11 percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

These increases were partially offset by:

- $7.6 million decrease due to a non-recurring adjustment recorded in the prior-year period to update the estimate for gas delivered to customers but not yet billed to reflect base rate changes.
- $7.0 million decrease related to a prior-year reversal of an accrual for estimated unrecoverable gas costs that did not recur in the current year.
- $1.6 million decrease in revenue-related taxes, primarily due to a decrease in revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $7.8 million, primarily due to the following:

- $5.4 million decrease due to a state sales tax reimbursement received in March 2010.
- $4.6 million decrease due to the absence of an impairment charge for available-for-sale securities recorded in the prior year.
- $4.5 million decrease in contract labor expenses.
- $4.6 million decrease in travel, legal and other administrative costs.

These decreases were partially offset by:

- $7.5 million increase in employee-related expenses.
- $4.5 million increase in taxes, other than income.

Miscellaneous income decreased $4.4 million due to lower interest income. Interest charges decreased $5.5 million primarily due to lower short-term debt balances and interest rates.

Additionally, results for the fiscal year ended September 30, 2009, were favorably impacted by a one-time tax benefit of $10.5 million. During the second quarter of fiscal 2009, the Company completed a study of the calculations used to estimate its deferred tax rate, and concluded that revisions to these calculations to include more specific jurisdictional tax rates would result in a more accurate calculation of the tax rate at which deferred taxes would reverse in the future. Accordingly, the Company modified the tax rate used to calculate deferred taxes from 38 percent to an individual rate for each legal entity. These rates vary from 36-41 percent depending on the jurisdiction of the legal entity.

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 excess gas.

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 Mid-Tex service area. 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 and demand for natural gas 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. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our 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, 2011, 2010, and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$125,973	$102,891	$ 89,348	$ 23,082	$ 13,543
Third-party transportation	73,676	73,648	95,314	28	(21,666)
Storage and park and lend services	7,995	10,657	11,858	(2,662)	(1,201)
Other	11,729	15,817	13,138	(4,088)	2,679
Gross profit	219,373	203,013	209,658	16,360	(6,645)
Operating expenses	111,098	105,975	116,495	5,123	(10,520)
Operating income	108,275	97,038	93,163	11,237	3,875
Miscellaneous income	4,715	135	1,433	4,580	(1,298)
Interest charges	31,432	31,174	30,982	258	192
Income before income taxes	81,558	65,999	63,614	15,559	2,385
Income tax expense	29,143	24,513	22,558	4,630	1,955
Net income	$ 52,415	$ 41,486	$ 41,056	$ 10,929	$ 430
Gross pipeline transportation volumes — MMcf	620,904	634,885	706,132	(13,981)	(71,247)
Consolidated pipeline transportation volumes — MMcf	435,012	428,599	528,689	6,413	(100,090)

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

On April 18, 2011, the Railroad Commission of Texas (RRC) issued an order in the rate case of Atmos Pipeline — Texas (APT) that was originally filed in September 2010. The RRC approved an annual operating income increase of $20.4 million as well as the following major provisions that went into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity
- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- An annual adjustment mechanism, which was approved for a three-year pilot program, that will adjust regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly customer charges.

The $16.4 million increase in regulated transmission and storage gross profit was attributable primarily to the following:

- $23.4 million net increase as a result of the rate case that was finalized and became effective in May 2011.
- $3.2 million increase associated with our most recent GRIP filing.

These increases were partially offset by the following:

- $4.8 million decrease due to the absence of the sale of excess gas, which occurred in the prior year.
- $4.4 million decrease due to a decline in throughput to our Mid-Tex Division primarily due to warmer than normal weather during fiscal 2011.

Operating expenses increased $5.1 million primarily due to the following:

- $4.6 million increase due to higher depreciation expense.
- $2.0 million increase due to the absence of a state sales tax reimbursement received in the prior year.

These increases were partially offset by the following:

- $0.8 million decrease related to lower levels of pipeline maintenance activities.
- $0.7 million decrease due to lower employee-related expenses.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $6.6 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $13.3 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.
- $2.6 million decrease due to decreased through-system volumes primarily associated with market conditions that resulted in reduced wellhead production, decreased drilling activity and increased competition, partially offset by increased deliveries to our Mid-Tex Division.
- $1.6 million net decrease in market-based demand fees, priority reservation fees and compression activity associated with lower throughput.

These decreases were partially offset by the following:

- $9.3 million increase associated with our GRIP filings.
- $2.0 million increase of excess inventory sales in the current-year period.

Operating expenses decreased $10.5 million primarily due to:

- $11.8 million decrease related to reduced contract labor.
- $2.0 million decrease due to a state sales tax reimbursement received in March 2010.

These decreases were partially offset by a $2.1 million increase in taxes, other than income due to higher ad valorem and payroll taxes.

Miscellaneous income decreased $1.3 million due primarily to a decline in intercompany interest income.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEH continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEH may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions. If AEH elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to offset the original financial instruments. If AEH elects to defer the withdrawal of gas, it will execute new financial instruments to correspond to the revised withdrawal schedule and allow the original financial instrument to settle as contracted.

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

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

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could cause an increase in the amount of cash required to collateralize our risk management liabilities.

Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the fiscal years ended September 30, 2011, 2010 and 2009 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

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

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$ 58,990	$ 59,523	$ 75,341	$ (533)	$(15,818)
Storage and transportation services	14,570	13,206	12,784	1,364	422
Other	5,265	5,347	9,365	(82)	(4,018)
	78,825	78,076	97,490	749	(19,414)
Asset optimization[1]	(3,424)	43,805	52,507	(47,229)	(8,702)
Total realized margins	75,401	121,881	149,997	(46,480)	(28,116)
Unrealized margins	(10,401)	(7,790)	(35,889)	(2,611)	28,099
Gross profit	65,000	114,091	114,108	(49,091)	(17)
Operating expenses, excluding asset impairment	39,113	44,147	49,046	(5,034)	(4,899)
Asset impairment	30,270	—	181	30,270	(181)
Operating income (loss)	(4,383)	69,944	64,881	(74,327)	5,063
Miscellaneous income	657	3,859	6,399	(3,202)	(2,540)
Interest charges	4,015	10,584	14,350	(6,569)	(3,766)
Income (loss) before income taxes	(7,741)	63,219	56,930	(70,960)	6,289
Income tax expense (benefit)	(209)	24,815	23,815	(25,024)	1,000
Net income (loss)	$ (7,532)	$ 38,404	$ 33,115	$(45,936)	$ 5,289
Gross nonregulated delivered gas sales volumes — MMcf	446,903	420,203	441,081	26,700	(20,878)
Consolidated nonregulated delivered gas sales volumes — MMcf	384,799	353,853	370,569	30,946	(16,716)
Net physical position (Bcf)	21.0	15.7	15.9	5.3	(0.2)

(1) Net of storage fees of $15.2 million, $13.2 million and $10.8 million.

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

Realized margins for gas delivery, storage and transportation services and other services were $78.8 million during the year ended September 30, 2011 compared with $78.1 million for the prior-year period. The increase primarily reflects the following:

- $1.4 million increase in margins from storage and transportation services, primarily attributable to new drilling projects in the Barnett Shale area.

- $0.6 million decrease in gas delivery and other services primarily due to lower per-unit margins partially offset by a nine percent increase in consolidated delivered gas sales volumes due to new customers in the power generation market. Per-unit margins were $0.13/Mcf in the current year compared with $0.14/Mcf in the prior year. The year-over-year decrease in per-unit margins reflects the impact of increased competition and lower basis spreads.

The $47.2 million decrease in realized asset optimization margins from the prior year primarily reflects the unfavorable impact of weak natural gas market fundamentals which provided fewer favorable trading opportunities.

Unrealized margins decreased $2.6 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses decreased $5.0 million primarily due to lower employee-related expenses and ad valorem taxes.

During fiscal 2011, our nonregulated segment recognized $30.3 million of non-cash asset impairment charges associated with two projects. In March 2011, we recorded a $19.3 million charge to substantially write off our investment in Fort Necessity. This project began in February 2008 when Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. At that time, we evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Additionally, during the third quarter of fiscal 2011, we recorded an $11.0 million non-cash charge to impair certain natural gas gathering assets of Atmos Gathering Company. The charge reflected a reduction in the value of the project due to the current low natural gas price environment and the adverse impact of an ongoing lawsuit associated with the project.

Interest charges decreased $6.6 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEH monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEH's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEH's economic value and its potential gross profit (loss) at September 30, 2011 and 2010.

	September 30	
	2011	2010
	(In millions, unless otherwise noted)	
Economic value	$ 4.9	$ (7.5)
Associated unrealized losses	14.7	12.8
Subtotal	19.6	5.3
Related fees[(1)]	(17.7)	(10.6)
Potential gross profit (loss)	$ 1.9	$ (5.3)
Net physical position (Bcf)	21.0	15.7

(1) Related fees represent the contractual costs to acquire the storage capacity utilized in our nonregulated segment's asset optimization operations. The fees primarily consist of demand fees and contractual obligations to sell gas below market index in exchange for the right to manage and optimize third party storage assets for the positions we have entered into as of September 30, 2011 and 2010.

During the 2011 fiscal year, our nonregulated segment's economic value increased from a negative economic value of ($7.5) million, or ($0.48)/Mcf at September 30, 2010 to $4.9 million, or $0.23/Mcf at September 30, 2011.

The increase in economic value was attributable to several factors including an increase in the captured spread value resulting from realizing financial instruments with lower spread values, entering into financial hedges with higher average prices and rolling financial instruments to forward periods to capture incremental value. Additionally, as a result of falling gas prices throughout the year, we injected a net 5.3 Bcf, which reduced the overall weighted average cost of gas held in storage.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEH actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit as of September 30, 2011 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

Realized margins for gas delivery, storage and transportation services and other services contributed 64 percent to total realized margins during fiscal 2010, with asset optimization activities contributing the remaining 36 percent. In fiscal 2009, gas delivery, storage and transportation services and other services represented 65 percent of the nonregulated segment's realized margins with asset optimization contributing the remaining 35 percent. The $28.1 million decrease in realized gross profit reflected:

- $19.4 million decrease in gas delivery, storage and transportation services and other services as a result of narrowing basis spreads, combined with lower delivered sales volumes. Per-unit delivered gas margins were $0.14/Mcf in fiscal 2010, compared with $0.17/Mcf in fiscal 2009, while delivered gas volumes were 5 percent lower in fiscal 2010 when compared with fiscal 2009.

- $8.7 million decrease in asset optimization due to lower margins earned on storage optimization activities, lower basis gains earned from utilizing leased capacity and lower margins earned on asset management plans, partially offset by higher realized storage and trading gains during fiscal 2010.

The decrease in realized gross profit was offset by a $28.1 million increase in unrealized margins due to the period-over-period timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments decreased $5.1 million primarily due a decrease in employee and other administrative costs, partially offset by an increase in gas gathering activities.

LIQUIDITY AND CAPITAL RESOURCES

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

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. During fiscal 2011, we executed on our strategy of consolidating our short-term facilities used for our regulated operations into a single line of credit, including the following:

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased during fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.
- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

As a result of these changes, we now have $985 million of availability from our commercial paper program and four committed revolving credit facilities with third parties.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011 using commercial paper borrowings. In effect, we refinanced this debt on a long-term basis through the issuance of $400 million 5.50% 30-year unsecured senior notes on June 10, 2011. On September 30, 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury lock and settlement. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks. Substantially all of the net proceeds of approximately $394 million were used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Additionally, we had planned to issue $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound. A pretax cash gain of approximately $28 million was recorded in March 2011.

Finally, we intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for fiscal year 2012.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, 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, 2011, 2010 and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(In thousands)		
Total cash provided by (used in)					
Operating activities	$ 582,844	$ 726,476	$ 919,233	$(143,632)	$(192,757)
Investing activities	(627,386)	(542,702)	(517,201)	(84,684)	(25,501)
Financing activities	44,009	(163,025)	(337,546)	207,034	174,521
Change in cash and cash equivalents	(533)	20,749	64,486	(21,282)	(43,737)
Cash and cash equivalents at beginning of period	131,952	111,203	46,717	20,749	64,486
Cash and cash equivalents at end of period	$ 131,419	$ 131,952	$ 111,203	$ (533)	$ 20,749

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, 2011 compared with fiscal year ended September 30, 2010

For the fiscal year ended September 30, 2011, we generated operating cash flow of $582.8 million from operating activities compared with $726.5 million in the prior year. The year-over-year decrease reflects the absence of an $85 million income tax refund received in the prior year coupled with the timing of gas cost recoveries under our purchased gas cost mechanisms and other net working capital changes.

Fiscal Year ended September 30, 2010 compared with fiscal year ended September 30, 2009

For the fiscal year ended September 30, 2010, we generated operating cash flow of $726.5 million from operating activities compared with $919.2 million in fiscal 2009, primarily due to the fluctuation in gas costs. Gas costs, which reached historically high levels during the 2008 injection season, declined sharply when the economy slipped into the recession and have remained relatively stable since that time. Operating cash flows for the fiscal 2010 period reflect the recovery of lower gas costs through purchased gas recovery mechanisms and sales. This is in contrast to the fiscal 2009 period, where operating cash flows were favorably influenced by the recovery of high gas costs during a period of falling prices.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide safe and reliable 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.

In early fiscal 2010, two coalitions of cities, representing the majority of the cities our Mid-Tex Division serves, agreed to a program of installing, beginning in the first quarter of fiscal 2011, 100,000 steel service line replacements during fiscal 2011 and 2012, with approved recovery of the associated return, depreciation and taxes. During fiscal 2011, we replaced 35,852 lines for a cost of $49.7 million. The program is progressing on schedule for completion in September 2012. As a result of this project and spending to replace our regulated customer service systems and our nonregulated energy trading risk management system, we anticipate capital expenditures will remain elevated during the next fiscal year.

For the fiscal year ended September 30, 2011, we incurred $623.0 million for capital expenditures compared with $542.6 million for the fiscal year ended September 30, 2010 and $509.5 million for the fiscal year ended September 30, 2009.

The $80.4 million increase in capital expenditures in fiscal 2011 compared to fiscal 2010 primarily reflects spending for the steel service line replacement program in the Mid-Tex Division, the development of new customer billing and information systems for our natural gas distribution and our nonregulated segments and the construction of a new customer contact center in Amarillo, Texas, partially offset by costs incurred in the prior fiscal year to relocate the company's information technology data center.

The $33.1 million increase in capital expenditures in fiscal 2010 compared to fiscal 2009 primarily reflects spending for the relocation of our information technology data center to a new facility, the construction of two service centers and the steel service line replacement program in our Mid-Tex Division.

Cash flows from financing activities

For the fiscal year ended September 30, 2011, our financing activities generated $44.0 million in cash, while financing activities for the fiscal year ended September 30, 2010 used $163.0 million in cash compared with cash of $337.5 million used for the fiscal year ended September 30, 2009. Our significant financing activities for the fiscal years ended September 30, 2011, 2010 and 2009 are summarized as follows:

2011

During the fiscal year ended September 30, 2011, we:

- Received $394.5 million net cash proceeds in June 2011 related to the issuance of $400 million 5.50% senior notes due 2041.
- Borrowed a net $83.3 million under our short-term facilities to fund working capital needs.
- Received $27.8 million cash in March 2011 related to the unwinding of two Treasury locks.
- Received $20.1 million cash in June 2011 related to the settlement of three Treasury locks associated with the $400 million 5.50% senior notes offering.
- Received $7.8 million net proceeds related to the issuance of 0.3 million shares of common stock.

- Paid $360.1 million for scheduled long-term debt repayments, including our $350 million 7.375% senior notes that were paid on their maturity date on May 15, 2011.
- Paid $124.0 million in cash dividends which reflected a payout ratio of 60 percent of net income.
- Paid $5.3 million for the repurchase of equity awards.

2010

During the fiscal year ended September 30, 2010, we:

- Paid $124.3 million in cash dividends which reflected a payout ratio of 61 percent of net income.
- Paid $100.5 million for the repurchase of common stock under an accelerated share repurchase agreement.
- Borrowed a net $54.3 million under our short-term facilities due to the impact of seasonal natural gas purchases.
- Received $8.8 million net proceeds related to the issuance of 0.4 million shares of common stock, which is a 68 percent decrease compared to the prior year due primarily to the fact that beginning in fiscal 2010 shares were purchased on the open market rather than being issued by us to the Direct Stock Purchase Plan and the Retirement Savings Plan.
- Paid $1.2 million to repurchase equity awards.

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 short-term borrowings under our credit facilities.
- Paid $121.5 million in cash dividends which reflected a payout ratio of 64 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.

The following table shows the number of shares issued for the fiscal years ended September 30, 2011, 2010 and 2009:

	For the Fiscal Year Ended September 30		
	2011	2010	2009
Shares issued:			
Direct stock purchase plan	—	103,529	407,262
Retirement savings plan	—	79,722	640,639
1998 Long-term incentive plan	675,255	421,706	686,046
Outside directors stock-for-fee plan	2,385	3,382	3,079
Total shares issued	677,640	608,339	1,737,026

The number of shares issued in fiscal 2011 compared with the number of shares issued in fiscal 2010 primarily reflects an increased number of shares issued under our 1998 Long-Term Incentive Plan due to the exercise of stock options during the current fiscal year. This increase was partially offset by the fact that we are purchasing shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During fiscal 2011, we cancelled and retired 169,793 shares attributable to federal withholdings on equity awards and repurchased and retired 375,468 shares attributable to our 2010 accelerated share repurchase agreement described below, which are not included in the table above.

The year-over-year decrease in the number of shares issued in fiscal 2010 compared with the number of shares issued in fiscal 2009, primarily reflects the fact that in fiscal 2010, we began to purchase shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. Further, a higher average stock price during the second and third quarters of fiscal 2010 compared to the second and third quarters of 2009 enabled us to issue fewer shares during fiscal 2010. Additionally, during fiscal 2010, we cancelled and retired 37,365 shares attributable to federal withholdings on equity awards and repurchased and retired 2,958,580 common shares as part of our 2010 accelerated share repurchase agreement described below, which are not included in the table above.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares, which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company.

Credit Facilities

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

As of September 30, 2011, we financed our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided $985 million of working capital funding. As of September 30, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was $702.5 million. These facilities are described in further detail in Note 7 to the consolidated financial statements.

On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.

In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased in fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.

In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At September 30, 2011, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Credit Ratings

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

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). On May 11, 2011, Moody's upgraded our senior unsecured debt rating to Baa1 from Baa2, with a ratings outlook of stable, citing steady rate increases, improving credit metrics and a strategic focus on lower risk regulated activities as reasons for the upgrade. On June 2, 2011, Fitch upgraded our senior unsecured debt rating to A- from BBB+, with a ratings outlook of stable, citing a constructive regulatory environment, strategic focus on lower risk regulated activities and the geographic diversity of our regulated operations as key rating factors. As of September 30, 2011, S&P maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa1	A-
Commercial paper	A-2	P-2	F-2

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2011. Our debt covenants are described in Note 7 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2011 and 2010:

	September 30			
	2011		2010	
	(In thousands, except percentages)			
Short-term debt	$ 206,396	4.4%	$ 126,100	2.8%
Long-term debt	2,208,551	47.3%	2,169,682	48.5%
Shareholders' equity	2,255,421	48.3%	2,178,348	48.7%
Total capitalization, including short-term debt	$4,670,368	100.0%	$4,474,130	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.7 percent and 51.3 percent at September 30, 2011 and 2010. The increase in the debt to capitalization ratio primarily reflects an increase in short-term debt as of September 30, 2011 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 intend to continue to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2011.

	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]	$2,212,565	$ 2,434	$250,131	$500,000	$1,460,000
Short-term debt[1]	206,396	206,396	—	—	—
Interest charges[2]	1,574,702	136,452	250,841	198,596	988,813
Gas purchase commitments[3]	460,179	274,985	185,194	—	—
Capital lease obligations[4]	1,194	186	372	372	264
Operating leases[4]	199,567	17,718	33,365	30,376	118,108
Demand fees for contracted storage[5]	19,339	11,421	6,770	983	165
Demand fees for contracted transportation[6]	37,295	13,941	19,929	3,425	—
Financial instrument obligations[7]	93,542	15,453	78,089	—	—
Postretirement benefit plan contributions[8]	194,323	31,519	28,543	35,122	99,139
Total contractual obligations	$4,999,102	$710,505	$853,234	$768,874	$2,666,489

(1) See Note 7 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, 2011.

(4) See Note 14 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our nonregulated segment. 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 nonregulated segment.

(7) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2011. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled. The table above excludes $1.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations.

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

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2011, AEH was committed to purchase 103.3 Bcf within one year, 46.4 Bcf within one to three years and 0.9 Bcf after three years under indexed contracts. AEH is committed to purchase 4.2 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.49 to $6.36 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 natural 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, 2011 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 and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our nonregulated 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 nonregulated 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 nonregulated segment.

Also, in our nonregulated 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, 2011 (in thousands):

Fair value of contracts at September 30, 2010	$(49,600)
Contracts realized/settled	(51,136)
Fair value of new contracts	2,584
Other changes in value	18,875
Fair value of contracts at September 30, 2011	$(79,277)

The fair value of our natural gas distribution segment's financial instruments at September 30, 2011, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2011				
	Maturity in years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(12,413)	$(66,864)	$—	$—	$(79,277)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(12,413)	$(66,864)	$—	$—	$(79,277)

The tables above include $1.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations.

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the fiscal year ended September 30, 2011 (in thousands):

Fair value of contracts at September 30, 2010	$(12,374)
Contracts realized/settled	4,017
Fair value of new contracts	—
Other changes in value	(16,693)
Fair value of contracts at September 30, 2011	(25,050)
Netting of cash collateral	28,787
Cash collateral and fair value of contracts at September 30, 2011	$ 3,737

The fair value of our nonregulated segment's financial instruments at September 30, 2011, is presented below by time period and fair value source.

	Fair Value of Contracts at September 30, 2011				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(14,823)	$(10,050)	$(177)	$—	$(25,050)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(14,823)	$(10,050)	$(177)	$—	$(25,050)

Employee Benefit Programs

An important element of our total compensation program, and a significant component of our operation and maintenance expense, is the offering of various benefit programs to our employees. These programs include medical and dental insurance coverage and pension and postretirement programs.

Medical and Dental Insurance

We offer medical and dental insurance programs to substantially all of our employees, and we believe these programs are consistent with other programs in our industry. Since 2005, we have experienced medical and prescription inflation of approximately seven percent. In recent years, we have strived to actively manage our health care costs through the introduction of a wellness strategy that is focused on helping employees to identify health risks and to manage these risks through improved lifestyle choices.

In March 2010, President Obama signed *The Patient Protection and Affordable Care Act* into law (the "Health Care Reform Act"). The Health Care Reform Act will be phased in over an eight-year period. Although we are still assessing the impact of the Health Care Reform Act on the health care benefits we provide to our employees, the design of our health care plans has already changed in order to comply with provisions of the Health Care Reform Act that have already gone into effect or will be going into effect in fiscal 2012. For example, lifetime maximums on benefits have been eliminated, coverage for dependent children has been extended to age 26 and all costs of preventive coverage must be paid for by the insurer. In 2014, health insurance exchanges will open in each state in order to provide a competitive marketplace for purchasing health insurance by individuals. Companies who offer health insurance to their employees could face a substantial increase in premiums at that time if they choose to continue to provide such coverage. However, companies who elect to cease providing health insurance to their employees will be faced with paying significant penalties to the federal government for each employee who receives coverage through an exchange. We will continue to monitor all developments on health care reform and continue to comply with all existing relevant laws and regulations.

For fiscal 2012, we anticipate an approximate 10 percent medical and prescription drug inflation rate, primarily due to anticipated higher claims costs and the implementation of the Health Care Reform Act.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2011, our total net periodic pension and other benefits costs was $56.6 million, compared with $50.8 million and $50.2 million for the fiscal years ended September 30, 2010 and 2009. 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.

Our fiscal 2011 costs were determined using a September 30, 2010 measurement date. As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates were significantly higher than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. Our expected return on our pension plan assets remained constant at 8.25 percent. Accordingly, our fiscal 2011 pension and postretirement medical costs were higher than in the prior year.

The increase in total net periodic pension and other benefits costs during fiscal 2010 compared with fiscal 2009 primarily reflects the decline in fair value of our plan assets. 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, 2009 measurement date, the interest rates were slightly lower than the interest rates at September 30, 2008, the measurement date used to determine our fiscal 2009 net periodic cost. 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. 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.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based on this valuation, we were required to contribute cash of $0.9 million to our pension plans during fiscal 2011. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold.

During fiscal 2010, we did not contribute cash to our pension plans as the fair value of the plans' assets recovered somewhat during the year from the unfavorable market conditions experienced in the latter half of calendar year 2008 and our plan assets were sufficient to achieve a desirable funding threshold as established by the PPA. During fiscal 2009, we contributed $21.0 million to our pension plans to achieve the same desired level of funding as established by the PPA.

We contributed $11.3 million, $11.8 million and $10.1 million to our postretirement benefits plans for the fiscal years ended September 30, 2011, 2010 and 2009. 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 2012 and Beyond

As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates, which impacted our fiscal 2012 net periodic pension and postretirement costs, were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. As a result of the lower interest and corporate bond rates, we decreased the discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is partially 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. Due to the decrease in our discount rate and our expected return on plan assets as well as the decline in the fair value of our plan assets, we expect our fiscal 2012 pension and postretirement medical costs to increase compared to fiscal 2011.

Based upon market conditions subsequent to September 30, 2011 the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $25 million and $30 million to the Plans in fiscal 2012. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. With respect to our postretirement medical plans, we anticipate contributing approximately $32 million during fiscal 2012.

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

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

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 nonregulated 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 nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. 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.

Nonregulated segment

Our nonregulated segment is also exposed to risks associated with changes in the market price of natural gas. For our nonregulated 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, 2011 of 0.1 Bcf, a $0.50 change in the forward NYMEX price would have had a $0.1 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, 2011 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 $6.7 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 $1.2 million during 2011.

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

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, 2011 and 2010, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2011, 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), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2011, 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 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 22, 2011

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2011	September 30 2010
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,607,552	$6,384,396
Construction in progress	209,242	157,922
	6,816,794	6,542,318
Less accumulated depreciation and amortization	1,668,876	1,749,243
Net property, plant and equipment	5,147,918	4,793,075
Current assets		
Cash and cash equivalents	131,419	131,952
Accounts receivable, less allowance for doubtful accounts of $7,440 in 2011 and $12,701 in 2010	273,303	273,207
Gas stored underground	289,760	319,038
Other current assets	316,471	150,995
Total current assets	1,010,953	875,192
Goodwill and intangible assets	740,207	740,148
Deferred charges and other assets	383,793	355,376
	$7,282,871	$6,763,791
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2011 — 90,296,482 shares, 2010 — 90,164,103 shares	$ 451	$ 451
Additional paid-in capital	1,732,935	1,714,364
Accumulated other comprehensive loss	(48,460)	(23,372)
Retained earnings	570,495	486,905
Shareholders' equity	2,255,421	2,178,348
Long-term debt	2,206,117	1,809,551
Total capitalization	4,461,538	3,987,899
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	291,205	266,208
Other current liabilities	367,563	413,640
Short-term debt	206,396	126,100
Current maturities of long-term debt	2,434	360,131
Total current liabilities	867,598	1,166,079
Deferred income taxes	960,093	829,128
Regulatory cost of removal obligation	428,947	350,521
Deferred credits and other liabilities	564,695	430,164
	$7,282,871	$6,763,791

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,531,863	$2,842,638	$2,884,796
Regulated transmission and storage segment	219,373	203,013	209,658
Nonregulated segment	2,024,893	2,146,658	2,283,988
Intersegment eliminations	(428,495)	(472,474)	(509,331)
	4,347,634	4,719,835	4,869,111
Purchased gas cost			
Natural gas distribution segment	1,487,499	1,820,627	1,887,192
Regulated transmission and storage segment	—	—	—
Nonregulated segment	1,959,893	2,032,567	2,169,880
Intersegment eliminations	(426,999)	(470,864)	(507,639)
	3,020,393	3,382,330	3,549,433
Gross profit	1,327,241	1,337,505	1,319,678
Operating expenses			
Operation and maintenance	449,290	460,513	485,704
Depreciation and amortization	227,099	211,589	211,984
Taxes, other than income	178,683	188,252	180,242
Asset impairments	30,270	—	5,382
Total operating expenses	885,342	860,354	883,312
Operating income	441,899	477,151	436,366
Miscellaneous income (expense), net	21,499	(156)	(3,067)
Interest charges	150,825	154,360	152,638
Income from continuing operations before income taxes	312,573	322,635	280,661
Income tax expense	113,689	124,362	97,362
Income from continuing operations	198,884	198,273	183,299
Income from discontinued operations, net of tax ($5,502, $4,425 and $2,929)	8,717	7,566	7,679
Net income	$ 207,601	$ 205,839	$ 190,978
Basic earnings per share			
Income per share from continuing operations	$ 2.18	$ 2.14	$ 1.99
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — basic	$ 2.28	$ 2.22	$ 2.08
Diluted earnings per share			
Income per share from continuing operations	$ 2.17	$ 2.12	$ 1.98
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — diluted	$ 2.27	$ 2.20	$ 2.07
Weighted average shares outstanding:			
Basic	90,201	91,852	91,117
Diluted	90,652	92,422	91,620

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, 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
Comprehensive income:						
Net income	—	—	—	—	205,839	205,839
Unrealized holding gains on investments, net	—	—	—	1,745	—	1,745
Treasury lock agreements, net	—	—	—	2,030	—	2,030
Cash flow hedges, net	—	—	—	(6,963)	—	(6,963)
Total comprehensive income						202,651
Repurchase of common stock	(2,958,580)	(15)	(100,435)	—	—	(100,450)
Repurchase of equity awards	(37,365)	—	(1,191)	—	—	(1,191)
Cash dividends ($1.34 per share)	—	—	—	—	(124,287)	(124,287)
Common stock issued:						
Direct stock purchase plan	103,529	1	2,881	—	—	2,882
Retirement savings plan	79,722	—	2,281	—	—	2,281
1998 Long-term incentive plan	421,706	2	8,708	—	—	8,710
Employee stock-based compensation	—	—	10,894	—	—	10,894
Outside directors stock-for-fee plan	3,382	—	97	—	—	97
Balance, September 30, 2010	90,164,103	451	1,714,364	(23,372)	486,905	2,178,348
Comprehensive income:						
Net income	—	—	—	—	207,601	207,601
Unrealized holding losses on investments, net	—	—	—	(1,647)	—	(1,647)
Treasury lock agreements, net	—	—	—	(28,689)	—	(28,689)
Cash flow hedges, net	—	—	—	5,248	—	5,248
Total comprehensive income						182,513
Repurchase of common stock	(375,468)	(2)	2	—	—	—
Repurchase of equity awards	(169,793)	(1)	(5,298)	—	—	(5,299)
Cash dividends ($1.36 per share)	—	—	—	—	(124,011)	(124,011)
Common stock issued:						
Direct stock purchase plan	—	—	(54)	—	—	(54)
1998 Long-term incentive plan	675,255	3	13,886	—	—	13,889
Employee stock-based compensation	—	—	9,958	—	—	9,958
Outside directors stock-for-fee plan	2,385	—	77	—	—	77
Balance, September 30, 2011	90,296,482	$451	$1,732,935	$(48,460)	$ 570,495	$2,255,421

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2011	2010	2009
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 207,601	$ 205,839	$ 190,978
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	30,270	—	5,382
Depreciation and amortization:			
Charged to depreciation and amortization	233,155	216,960	217,208
Charged to other accounts	228	173	94
Deferred income taxes	117,353	196,731	129,759
Stock-based compensation	11,586	12,655	14,494
Debt financing costs	9,438	11,908	10,364
Other	(961)	(1,245)	(1,177)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(96)	(40,401)	244,713
Decrease in gas stored underground	27,737	54,014	194,287
(Increase) decrease in other current assets	(38,048)	(18,387)	117,737
(Increase) decrease in deferred charges and other assets	(53,519)	14,886	(106,231)
Increase (decrease) in accounts payable and accrued liabilities	23,904	58,069	(181,978)
Decrease in other current liabilities	(57,495)	(48,992)	(717)
Increase in deferred credits and other liabilities	71,691	64,266	84,320
Net cash provided by operating activities	582,844	726,476	919,233
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(622,965)	(542,636)	(509,494)
Other, net	(4,421)	(66)	(7,707)
Net cash used in investing activities	(627,386)	(542,702)	(517,201)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	83,306	54,268	(283,981)
Net proceeds from issuance of long-term debt	394,466	—	445,623
Settlement of Treasury lock agreements	20,079	—	1,938
Unwinding of Treasury lock agreements	27,803	—	—
Repayment of long-term debt	(360,131)	(131)	(407,353)
Cash dividends paid	(124,011)	(124,287)	(121,460)
Repurchase of common stock	—	(100,450)	—
Repurchase of equity awards	(5,299)	(1,191)	—
Issuance of common stock	7,796	8,766	27,687
Net cash provided by (used in) financing activities	44,009	(163,025)	(337,546)
Net increase (decrease) in cash and cash equivalents	(533)	20,749	64,486
Cash and cash equivalents at beginning of year	131,952	111,203	46,717
Cash and cash equivalents at end of year	$ 131,419	$ 131,952	$ 111,203

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 three 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.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. The results of these operations have been separately reported as discontinued operations.

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 through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

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; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Basis of comparison — Certain prior-year amounts have been reclassified to conform with the current year presentation.

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, 2011 and 2010 included the following:

	September 30	
	2011	2010
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$254,666	$209,564
Merger and integration costs, net	6,242	6,714
Deferred gas costs	33,976	22,701
Regulatory cost of removal asset	8,852	31,014
Environmental costs	385	805
Rate case costs	4,862	4,505
Deferred franchise fees	379	1,161
Other	3,534	1,046
	$312,896	$277,510
Regulatory liabilities:		
Deferred gas costs	$ 8,130	$ 43,333
Regulatory cost of removal obligation	464,025	381,474
Other	14,025	6,112
	$486,180	$430,919

Currently, authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions. During the fiscal years ended September 30, 2011, 2010 and 2009, we recognized $0.5 million, $0.4 million and $0.4 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 nonregulated 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 nonregulated 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, 2011, 2010 and 2009, we included unrealized gains (losses) on open contracts of $(10.4) million, $(7.8) million and $(35.9) million as a component of nonregulated revenues.

Operating revenues for our regulated transmission and storage and nonregulated 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 substantially all 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 nonregulated segment 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 nonregulated segment utilizes 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 $1.7 million, $3.9 million and $4.9 million was capitalized in 2011, 2010 and 2009.

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 3.6 percent, 3.5 percent and 3.8 percent for the fiscal years ended September 30, 2011, 2010 and 2009.

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 50 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, 2011 and 2010, we recorded asset retirement obligations of $14.0 million and $11.4 million. Additionally, we recorded $5.4 million and $3.8 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 facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities 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 2011, we recorded pretax noncash impairment losses of $19.3 million related to our Fort Necessity storage project and $11.0 million related to our gathering system, as discussed in Note 5.

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, 2011 and 2010, 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 then 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 to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution and nonregulated 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 on our natural gas distribution segment as a result of the use of financial instruments.

In our nonregulated segment, we have designated most of the natural gas inventory held by this operating segment 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 nonregulated 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 is referred to as timing ineffectiveness.

In our nonregulated 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. As of September 30, 2011 and 2010, the Company netted $28.8 million and $24.9 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. In fiscal 2011 and 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 cash flow hedges 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. Hedge ineffectiveness to the extent incurred is reported as a component of interest expense.

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. Adverse developments in the last few years in the global financial and credit markets have periodically 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. Any further 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 — Represents 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. The Level 1 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents 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 and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 — Represents 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. Our Master Trust has investments in real estate that qualify as Level 3 fair value measurements. Currently, we have no other 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 9. 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.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan which was enhanced, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

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 based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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.

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

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, 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, 2011 and 2010, consisted of the following unrealized gains (losses):

	September 30	
	2011	2010
	(In thousands)	
Unrealized holding gains on investments	$ 2,558	$ 4,205
Treasury lock agreements	(34,157)	(5,468)
Cash flow hedges	(16,861)	(22,109)
	$(48,460)	$(23,372)

Subsequent events — We have evaluated subsequent events from the September 30, 2011 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 — During the year ended September 30, 2011, two new accounting standards became applicable to the Company pertaining to goodwill impairment testing for reporting units with zero or negative carrying amounts and disclosure of supplementary pro forma information for business combinations. The adoption of these standards had no impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the year ended September 30, 2011.

For interim and annual periods beginning after December 15, 2011, three new accounting pronouncements will become applicable to the Company including guidance that will change certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements, guidance related to the presentation of other comprehensive income which will require that all nonowner changes in shareholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements and new guidance related to goodwill impairment testing that will permit an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the traditional two-step goodwill impairment test. The adoption of these standards should not impact 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, 2011 and 2010:

	September 30 2011	September 30 2010
	(In thousands)	
Goodwill	$740,000	$739,314
Intangible assets	207	834
Total	$740,207	$740,148

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2011:

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
		(In thousands)		
Balance as of September 30, 2010	$572,262	$132,341	$34,711	$739,314
Deferred tax adjustments on prior acquisitions[(1)]	646	40	—	686
Balance as of September 30, 2011	$572,908	$132,381	$34,711	$740,000

(1) During the preparation of the fiscal 2011 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 $0.7 million.

Information regarding our intangible assets is reflected in the following table. As of September 30, 2011 and 2010, we had no intangible assets with indefinite lives.

	Useful Life (Years)	September 30, 2011 Gross Carrying Amount	September 30, 2011 Accumulated Amortization	September 30, 2011 Net	September 30, 2010 Gross Carrying Amount	September 30, 2010 Accumulated Amortization	September 30, 2010 Net
				(In thousands)			
Customer contracts	10	$6,926	$(6,719)	$207	$6,926	$(6,092)	$834

The following table presents actual amortization expense recognized during 2011 and an estimate of future amortization expense based upon our intangible assets at September 30, 2011.

Amortization expense (in thousands):

Actual for the fiscal year ending September 30, 2011	$627
Estimated for the fiscal year ending:	
September 30, 2012	$ 43
September 30, 2013	43
September 30, 2014	43
September 30, 2015	43
September 30, 2016	35

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

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

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, 2011 and 2010:

	Natural Gas Distribution	Nonregulated	Total
		(In thousands)	
September 30, 2011[3]			
Assets from risk management activities, current[1]	$ 843	$ 17,501	$ 18,344
Assets from risk management activities, noncurrent	998	—	998
Liabilities from risk management activities, current[1]	(11,916)	(3,537)	(15,453)
Liabilities from risk management activities, noncurrent	(67,862)	(10,227)	(78,089)
Net assets (liabilities)	$(77,937)	$ 3,737	$(74,200)
September 30, 2010			
Assets from risk management activities, current[2]	$ 2,219	$ 18,356	$ 20,575
Assets from risk management activities, noncurrent	47	890	937
Liabilities from risk management activities, current[2]	(48,942)	(731)	(49,673)
Liabilities from risk management activities, noncurrent	(2,924)	(6,000)	(8,924)
Net assets (liabilities)	$(49,600)	$ 12,515	$(37,085)

(1) Includes $28.8 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

(2) Includes $24.9 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

(3) The September 30, 2011 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations. At September 30, 2011, assets and liabilities held for sale included $1.3 million of current liabilities from risk management activities.

Regulated Commodity Risk Management Activities

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

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2010-2011 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 35 percent, or 31.7 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $5.81 per Mcf. We have not designated these financial instruments as hedges.

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

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers' request.

We also perform asset optimization activities in our nonregulated segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from 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 should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated segment is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. 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 nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 62 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

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

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

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2011, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.1 Bcf.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

We intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $300 million of a total $400 million of senior notes that were issued in June 2011. This offering is discussed in Note 7. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pre-tax cash gain of $27.8 million during the second quarter of fiscal 2011.

In prior years, we entered into several Treasury lock agreements to fix the Treasury yield component of the interest cost of financing for various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extends through fiscal 2041.

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, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(13,950)
	Cash Flow	—	38,713
	Not designated	26,977	31,648
		26,977	56,411

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, 2011 and 2010. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $28.8 million and $24.9 million of cash held on deposit in margin accounts as of September 30, 2011 and 2010 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our 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	Nonregulated	Total
			(In thousands)	
September 30, 2011				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	—	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(31,064)	(31,064)
Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[1]	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$(79,277)	$(25,050)	$(104,327)

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2010				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 40,030	$ 40,030
Noncurrent commodity contracts	Deferred charges and other assets	—	2,461	2,461
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(56,575)	(56,575)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(9,222)	(9,222)
Total		—	(23,306)	(23,306)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	2,219	16,459	18,678
Noncurrent commodity contracts	Deferred charges and other assets	47	2,056	2,103
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(48,942)	(7,178)	(56,120)
Noncurrent commodity contracts	Deferred credits and other liabilities	(2,924)	(405)	(3,329)
Total		(49,600)	10,932	(38,668)
Total Financial Instruments		$(49,600)	$(12,374)	$(61,974)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the years ended September 30, 2011, 2010 and 2009 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $24.8 million, $51.8 million and $6.4 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our consolidated income statement for the years ended September 30, 2011, 2010 and 2009 is presented below.

	Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Commodity contracts	$16,552	$34,650	$ 45,120
Fair value adjustment for natural gas inventory designated as the hedged item	9,824	19,867	(28,831)
Total impact on revenue	$26,376	$54,517	$ 16,289
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 803	$ (1,272)	$ 5,958
Timing ineffectiveness	25,573	55,789	10,331
	$26,376	$54,517	$ 16,289

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, 2011, 2010 and 2009 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Fiscal Year Ended September 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
		(In thousands)		
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(28,430)	$(28,430)
Loss arising from ineffective portion of commodity contracts	—	—	(1,585)	(1,585)
Total impact on revenue	—	—	(30,015)	(30,015)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,455)	—	—	(2,455)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total impact from cash flow hedges	$19,348	$6,000	$(30,015)	$ (4,667)

	Fiscal Year Ended September 30, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(44,809)	$(44,809)
Loss arising from ineffective portion of commodity contracts	—	—	(2,717)	(2,717)
Total impact on revenue	—	—	(47,526)	(47,526)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,678)	—	—	(2,678)
Total impact from cash flow hedges	$(2,678)	$ —	$(47,526)	$(50,204)

	Fiscal Year Ended September 30, 2009			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(136,540)	$(136,540)
Loss arising from ineffective portion of commodity contracts	—	—	(9,888)	(9,888)
Total impact on revenue	—	—	(146,428)	(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)	$ —	$(146,428)	$(150,498)

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 years ended September 30, 2011 and 2010. 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	
	2011	2010
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$(12,720)	$ 343
Forward commodity contracts	(12,096)	(34,296)
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	(15,969)	1,687
Forward commodity contracts	17,344	27,333
Total other comprehensive loss from hedging, net of tax[1]	$(23,441)	$ (4,933)

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2011. However, the table below does not include the expected recognition in earnings of the Treasury lock agreements entered into in August 2011 as those financial instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
2012	$(1,266)	$(12,160)	$(13,426)
2013	(1,266)	(3,214)	(4,480)
2014	(1,266)	(1,461)	(2,727)
2015	601	(29)	572
2016	770	3	773
Thereafter	10,812	—	10,812
Total[1]	$ 8,385	$(16,861)	$ (8,476)

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our consolidated income statements for the years ended September 30, 2011, 2010 and 2009 was an increase (decrease) in revenue of $(1.4) million, $15.4 million and $36.9 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

5. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The fair value of these assets is presented in Note 9 below.

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 tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2011 and 2010. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	September 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,841	$ —	$ —	$ 1,841
Nonregulated segment	15,262	97,396	—	(95,156)	17,502
Total financial instruments	15,262	99,237	—	(95,156)	19,343
Hedged portion of gas stored underground	47,940	—	—	—	47,940
Available-for-sale securities					
Money market funds	—	1,823	—	—	1,823
Registered investment companies	36,444	—	—	—	36,444
Bonds	—	14,366	—	—	14,366
Total available-for-sale securities	36,444	16,189	—	—	52,633
Total assets	$99,646	$115,426	$ —	$ (95,156)	$119,916
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 81,118	$ —	$ —	$ 81,118
Nonregulated segment	22,091	115,617	—	(123,943)	13,765
Total liabilities	$22,091	$196,735	$ —	$(123,943)	$ 94,883

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,266	$ —	$ —	$ 2,266
Nonregulated segment	18,544	42,462	—	(41,760)	19,246
Total financial instruments	18,544	44,728	—	(41,760)	21,512
Hedged portion of gas stored underground	57,507	—	—	—	57,507
Available-for-sale securities					
Money market funds	—	499	—	—	499
Registered investment companies	40,967	—	—	—	40,967
Total available-for-sale securities	40,967	499	—	—	41,466
Total assets	$117,018	$45,227	$ —	$(41,760)	$120,485
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,866	$ —	$ —	$ 51,866
Nonregulated segment	41,430	31,950	—	(66,649)	6,731
Total liabilities	$ 41,430	$83,816	$ —	$(66,649)	$ 58,597

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences. This level also includes municipal and corporate bonds where market data for pricing is observable.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting agreements and the remaining $16.4 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting agreements and the remaining $12.3 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of September 30, 2011:				
Domestic equity mutual funds	$27,748	$4,074	$ —	$31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	—	—	1,823
	$48,558	$4,351	$(276)	$52,633
As of September 30, 2010:				
Domestic equity mutual funds	$29,540	$5,698	$ —	$35,238
Foreign equity mutual funds	4,753	976	—	5,729
Money market funds	499	—	—	499
	$34,792	$6,674	$ —	$41,466

At September 30, 2011 and 2010, our available-for-sale securities included $38.3 million and $41.5 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans as discussed in Note 9. At September 30, 2011 we maintained investments in bonds that have contractual maturity dates ranging from January 2012 through January 2016.

We maintained an investment in one foreign equity mutual fund with a fair value of $2.3 million in an unrealized loss position of $0.2 million as of September 30, 2011. This fund has been in an unrealized loss position for less than twelve months. Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other-than-temporary as of September 30, 2011. We also maintained several bonds with a cumulative fair value of $9.9 million in an unrealized loss position of less than $0.1 million as of September 30, 2011. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment-grade, we do not consider this impairment to be other-than-temporary as of September 30, 2011.

At September 30, 2010, we did not maintain any investments that were in an unrealized loss position. In fiscal 2009, we recorded a $5.4 million noncash charge to impair certain available-for sale investments during the year ended September 30, 2009 due to the conditions of the financial markets at that time.

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. 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.

Atmos Gathering Company (AGC) owns and operates the Park City and Shrewsbury gathering systems in Kentucky. The Park City gathering system consists of a 23-mile low pressure pipeline and a nitrogen removal unit that was constructed in 2008. The Shrewsbury production, gathering and processing assets were acquired in 2008 at which time we sold the production assets to a third party. As a result of the sale of the production assets, we obtained a 10-year production payment note under which we were to be paid from future production generated from the assets.

As discussed in Note 13, AGC is involved in an ongoing lawsuit with the Park City gathering system. Due to the lawsuit and a low natural gas price environment, the assets have generated operating losses. As a result of these developments, we performed an impairment assessment of these assets during the third fiscal quarter and determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value of approximately $6 million and recorded a pre-tax noncash impairment loss of approximately $11 million. We used a combination of a market and income approach in a weighted average discounted cash flow analysis that included significant inputs such as our weighted average cost of capital and assumptions regarding future natural gas prices. This is a Level 3 fair value measurement because the inputs used are unobservable. Based on this analysis, we determined the assets to be impaired.

In February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pretax noncash impairment loss to write off substantially all of our investment in the project.

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of September 30, 2011:

	September 30, 2011
	(In thousands)
Carrying Amount	$2,212,565
Fair Value	$2,560,945

6. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

	Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Operating revenues	$80,028	$69,855	$99,969
Purchased gas cost	48,759	42,419	72,945
Gross profit	31,269	27,436	27,024
Operating expenses	16,854	15,151	15,988
Operating income	14,415	12,285	11,036
Other nonoperating expense	(196)	(294)	(428)
Income from discontinued operations before income taxes	14,219	11,991	10,608
Income tax expense	5,502	4,425	2,929
Net income	$ 8,717	$ 7,566	$ 7,679

The following table presents balance sheet data related to assets held for sale.

	September 30, 2011
	(In thousands)
Net plant, property & equipment	$127,577
Gas stored underground	11,931
Other current assets	786
Deferred charges and other assets	277
Assets held for sale	$140,571
Accounts payable and accrued liabilities	$ 1,917
Other current liabilities	4,877
Regulatory cost of removal	10,498
Deferred credits and other liabilities	1,153
Liabilities held for sale	$ 18,445

7. Debt

Long-term debt

Long-term debt at September 30, 2011 and 2010 consisted of the following:

	2011	2010
	(In thousands)	
Unsecured 7.375% Senior Notes, redeemed May 2011	$ —	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	—
Medium term notes		
Series A, 1995-2, 6.27%, redeemed December 2010	—	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term notes due in installments through 2013	262	393
Total long-term debt	2,212,565	2,172,696
Less:		
Original issue discount on unsecured senior notes and debentures	(4,014)	(3,014)
Current maturities	(2,434)	(360,131)
	$2,206,117	$1,809,551

As noted above, our unsecured 10% notes will mature in December 2011; accordingly, these have been classified within the current maturities of long-term debt.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011, using commercial paper borrowings. We replaced these senior notes on June 10, 2011 with $400 million 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks discussed in Note 4. Substantially all of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Short-term debt

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

Prior to the third quarter of fiscal 2011, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. On April 13, 2011, our $200 million 180-day unsecured credit facility expired and was not replaced. On May 2, 2011, we replaced our $566.7 million unsecured credit facility with a new five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion. On September 30, 2011, we renewed our 364-day revolving line of credit facility used to backstop letters of credit for our regulated operations and increased the borrowing capacity from $6.25 million to $10 million. As a result of these changes, we have $985 million of working capital funding from our commercial paper program and four committed revolving credit facilities with third-party lenders.

At September 30, 2011 and 2010, there was $206.4 million and $126.1 million outstanding under our commercial paper program. As of September 30, 2011 our commercial paper had maturities of less than one week with interest rates of 0.29 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding. The first facility is a five-year $750 million unsecured facility, expiring May 2016, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 2 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At September 30, 2011, there were no borrowings under this facility, but we had $206.4 million of commercial paper outstanding leaving $543.6 million available.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At September 30, 2011, there were no borrowings outstanding under this facility.

The third facility is a $10 million revolving credit facility used primarily to issue letters of credit that bears interest at a LIBOR-based rate. At September 30, 2011, there were no borrowings outstanding under this credit facility; however, letters of credit totaling $5.9 million had been issued under the facility at September 30, 2011, which reduced the amount available by a corresponding amount.

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, 2011, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $350 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There was $181.3 million outstanding under this facility at September 30, 2011.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest federal funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At September 30, 2011, there were no borrowings outstanding under this credit facility. However, at September 30, 2011, AEM letters of credit totaling $20.2 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 $129.8 million at September 30, 2011.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At September 30, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.33 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at September 30, 2011, AEM's net working capital was $131.8 million and its tangible net worth was $144.5 million.

To supplement borrowings under this facility, AEH has a $350 million intercompany demand credit facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There were no borrowings outstanding under this facility at September 30, 2011.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities prior to our $400 million senior notes offering in June 2011. At September 30, 2011, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

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

Further, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of 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, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

Maturities of long-term debt at September 30, 2011 were as follows (in thousands):

2012	$ 2,434
2013	250,131
2014	—
2015	500,000
2016	—
Thereafter	1,460,000
	$2,212,565

8. Stock and Other Compensation Plans

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans. We paid $100 million to Goldman Sachs & Co. on July 7, 2010 in a share forward transaction and received 2,958,580 shares of Atmos Energy common stock. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 our Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company.

Stock-Based Compensation Plans

Total stock-based compensation expense was $11.6 million, $12.7 million and $14.5 million for the fiscal years ended September 30, 2011, 2010 and 2009, 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.

As of September 30, 2011, 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. In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange. As of September 30, 2011, 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 319,700 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 units 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 fair value of the awards granted is based on the market price of our stock at the date of grant. The associated expense is recognized ratably over the vesting period.

Employees who are granted shares of time-lapse restricted stock under our LTIP have a nonforfeitable right to dividends that are paid at the same rate at which they are paid on shares of stock without restrictions. In addition, employees who are granted shares of time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate at which they are paid on shares of stock without restrictions. Both time-lapse restricted stock and time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in either the time-lapse restricted stock or time-lapse restricted stock units.

Employees who are granted shares of performance-based restricted stock units under our LTIP have a forfeitable right to dividends that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividends on the performance-based restricted stock units are paid in the form of shares upon the vesting of the award. Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2011, 2010 and 2009:

	2011		2010		2009	
	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	1,293,960	$27.28	1,295,841	$27.23	1,096,770	$29.04
Granted	491,345	33.10	551,278	29.07	711,909	25.76
Vested	(464,321)	27.21	(493,957)	29.24	(499,267)	29.05
Forfeited	(56,842)	27.56	(59,202)	26.54	(13,571)	28.92
Nonvested at end of year	1,264,142	$29.56	1,293,960	$27.28	1,295,841	$27.23

As of September 30, 2011, there was $18.0 million of total unrecognized compensation cost related to nonvested time-lapse restricted shares and restricted stock units 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, 2011, 2010 and 2009 was $12.6 million, $14.4 million and $14.5 million.

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2011		2010		2009	
	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	434,962	$22.46	611,227	$21.88	913,841	$22.54
Granted	—	—	—	—	—	—
Exercised	(348,196)	22.54	(176,265)	20.44	(130,965)	21.99
Forfeited	—	—	—	—	—	—
Expired	—	—	—	—	(171,649)	25.31
Outstanding at end of year[1]	86,766	$22.16	434,962	$22.46	611,227	$21.88
Exercisable at end of year[2]	86,766	$22.16	434,962	$22.46	611,227	$21.88

(1) The weighted-average remaining contractual life for outstanding options was 1.7 years, 1.6 years, and 2.4 years for fiscal years 2011, 2010 and 2009. The aggregate intrinsic value of outstanding options was $0.3 million, $1.6 million and $2.1 million for fiscal years 2011, 2010 and 2009.

(2) The weighted-average remaining contractual life for exercisable options was 1.7 years, 1.6 years and 2.4 years for fiscal years 2011, 2010 and 2009. The aggregate intrinsic value of exercisable options was $0.3 million, $1.6 million and $2.1 million for the fiscal years 2011, 2010 and 2009.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2011, 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
$21.23 to $22.99	71,064	1.4	$21.31
$23.00 to $26.19	15,702	3.3	$26.00
$21.23 to $26.19	86,766	1.7	$22.16

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Grant date weighted average fair value per share	$ —	$ —	$ —
Net cash proceeds from stock option exercises	$7,848	$3,604	$2,880
Income tax benefit from stock option exercises	$1,010	$ 547	$ 177
Total intrinsic value of options exercised	$1,263	$ 239	$ 262

As of September 30, 2011, 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 of Directors adopted the Outside Directors Stock-for-Fee Plan which was approved by our shareholders in February 1995. 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.

In addition, we adopted an incentive plan in October 2001 to give the employees in our nonregulated segment an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure 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.

9. 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.

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. 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, 2011				
Unrecognized transition obligation	$ —	$ —	$ 3,220	$ 3,220
Unrecognized prior service cost	(373)	—	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$182,113	$30,654	$ 41,899	$254,666
September 30, 2010				
Unrecognized transition obligation	$ —	$ —	$ 4,731	$ 4,731
Unrecognized prior service cost	(842)	—	(10,311)	(11,153)
Unrecognized actuarial loss	159,539	30,753	25,694	215,986
	$158,697	$30,753	$ 20,114	$209,564

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2011, 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. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan which was enhanced, effective January 1, 2011.

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 2011 and 2009, we contributed $0.9 million and $21.0 million in cash to the Plans to achieve a desired level of funding while maximizing the tax deductibility of this payment. In fiscal 2010, we did not make any contributions to our pension plans. Based upon market conditions subsequent to September 30, 2011, the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $25 million and $30 million to the Plans in fiscal 2012. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds.

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, 2011 and 2010.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2011	Actual Allocation September 30 2010
Domestic equities	35%-55%	40.4%	44.1%
International equities	10% - 20%	13.6%	14.4%
Fixed income	10%-30%	21.3%	19.0%
Company stock	5%-15%	13.5%	11.3%
Other assets	5%-15%	11.2%	11.2%

At September 30, 2011 and 2010, the Plan held 1,169,700 shares of our common stock, which represented 13.5 percent and 11.3 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.6 million and $1.6 million during fiscal 2011 and 2010.

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. 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, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2010, 2009 and 2008. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%[1]	5.52%	7.57%
Rate of compensation increase	3.50%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	7.75%	8.25%	8.25%	8.25%	8.25%

(1) The discount rate for the Pension Account Plan increased from 5.39% to 5.68% effective January 1, 2011 due to a curtailment gain recorded in the current fiscal year.

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Accumulated benefit obligation	$ 414,489	$ 391,915
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 407,536	$ 380,045
Service cost	14,384	13,499
Interest cost	22,264	20,870
Actuarial loss	12,944	19,809
Benefits paid	(27,534)	(26,687)
Curtailments	(162)	—
Benefit obligation at end of year	429,432	407,536
Change in plan assets:		
Fair value of plan assets at beginning of year	301,708	301,146
Actual return on plan assets	5,154	27,249
Employer contributions	876	—
Benefits paid	(27,534)	(26,687)
Fair value of plan assets at end of year	280,204	301,708
Reconciliation:		
Funded status	(149,228)	(105,828)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(149,228)	$(105,828)

Net periodic pension cost for the Plans for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 14,384	$ 13,499	$ 12,951
Interest cost	22,264	20,870	24,060
Expected return on assets	(24,817)	(25,280)	(24,950)
Amortization of prior service cost	(429)	(960)	(946)
Recognized actuarial loss	9,498	9,290	3,742
Curtailment gain	(40)	—	—
Net periodic pension cost	$ 20,860	$ 17,419	$ 14,857

The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2011 and 2010. As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The methods used to determine fair value for the assets held by the Master Trust are fully described in Note 2.

In addition to the assets shown below, the Master Trust had net accounts receivable of $0.4 million and $0.1 million at September 30, 2011 and 2010 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks	$ 94,336	$ —	$ —	$ 94,336
Money market funds	—	9,383	—	9,383
Registered investment companies	27,236	—	—	27,236
Common/collective trusts	53,309	—	—	53,309
Government securities	4,946	18,907	—	23,853
Corporate bonds	—	33,636	—	33,636
Limited partnerships	—	37,806	—	37,806
Real estate	—	—	200	200
Total investments at fair value	$179,827	$99,732	$200	$279,759

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks	$116,315	$ —	$ —	$116,315
Money market funds	—	10,013	—	10,013
Registered investment companies	32,601	—	—	32,601
Common/collective trusts	—	48,920	—	48,920
Government securities	5,548	16,296	—	21,844
Corporate bonds	—	33,987	—	33,987
Limited partnerships	—	37,691	—	37,691
Real estate	—	—	200	200
Total investments at fair value	$154,464	$146,907	$200	$301,571

The fair value of our Level 3 real estate assets was determined based on independent third party appraisals. There were no changes in the fair value of the Level 3 assets during the year ended September 30, 2011.

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 (SERP) (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.

In August 2009, the Board of Directors determined that there would be no new participants in the SERP subsequent to August 5, 2009, except for any corporate officers who may be appointed to the Management Committee. The SERP is a defined benefit arrangement which provides a benefit equal to 60 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SERP. However, the Board also established a new defined benefit supplemental executive retirement plan (the 2009 SERP), effective August 5, 2009, with each participant being selected by the Board, with each such participant being either (i) a corporate officer (other than such officer who is appointed as a member of the Company's Management Committee), (ii) a division president or (iii) an employee selected in the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of service and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Account Plan (currently 4.69%).

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, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2010, 2009 and 2008. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%	5.52%	7.57%
Rate of compensation increase	3.50%	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, 2011 and 2010:

	2011	2010
	(In thousands)	
Accumulated benefit obligation	$ 104,363	$ 99,673
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 108,919	$ 102,747
Service cost	2,768	2,476
Interest cost	5,825	5,224
Actuarial loss	2,140	3,043
Benefits paid	(7,537)	(4,571)
Benefit obligation at end of year	112,115	108,919
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	7,537	4,571
Benefits paid	(7,537)	(4,571)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(112,115)	(108,919)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(112,115)	$(108,919)

Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2011 and 2010, assets held in the rabbi trusts consisted of available-for-sale securities of $38.3 million and $41.5 million, which are included in our fair value disclosures in Note 5.

Net periodic pension cost for the supplemental plans for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$ 2,768	$2,476	$ 1,985
Interest cost	5,825	5,224	6,056
Amortization of transition asset	—	—	—
Amortization of prior service cost	—	187	212
Recognized actuarial loss	2,239	1,999	324
Curtailment	—	—	1,645
Net periodic pension cost	$10,832	$9,886	$10,222

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 2011 and 2010 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Supplemental Plans	
	2011	2010
	(In thousands)	
Projected Benefit Obligation	$112,115	$108,919
Accumulated Benefit Obligation	104,363	99,673
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)	
2012	$ 35,286	$25,116
2013	33,109	6,910
2014	31,753	4,738
2015	30,633	6,862
2016	30,648	4,622
2017-2021	146,923	43,625

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 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 $31.5 million to our postretirement benefits plan during fiscal 2012.

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, 2011 and 2010.

	Actual Allocation September 30	
Security Class	**2011**	**2010**
Diversified investment funds	96.8%	97.5%
Cash and cash equivalents	3.2%	2.5%

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, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2010, 2009 and 2008. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%	5.52%	7.57%
Expected return on plan assets	5.00%	5.00%	5.00%	5.00%	5.00%
Initial trend rate	8.00%	8.00%	8.00%	7.50%	8.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2018	2016	2016	2015	2015

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 228,234	$ 209,732
Service cost	14,403	13,439
Interest cost	12,813	12,071
Plan participants' contributions	2,892	2,734
Actuarial loss	17,966	2,980
Benefits paid	(13,046)	(12,722)
Subsidy payments	432	—
Benefit obligation at end of year	263,694	228,234
Change in plan assets:		
Fair value of plan assets at beginning of year	53,033	47,646
Actual return on plan assets	(1,500)	3,551
Employer contributions	11,254	11,824
Plan participants' contributions	2,892	2,734
Benefits paid	(13,046)	(12,722)
Subsidy payments	432	—
Fair value of plan assets at end of year	53,065	53,033
Reconciliation:		
Funded status	(210,629)	(175,201)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$(210,629)	$(175,201)

Net periodic postretirement cost for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$14,403	$13,439	$11,786
Interest cost	12,813	12,071	14,080
Expected return on assets	(2,727)	(2,460)	(2,292)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	(1,450)	(1,450)	—
Recognized actuarial loss	347	374	—
Net periodic postretirement cost	$24,897	$23,485	$25,085

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:

	One-Percentage Point Increase	One-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 4,155	$ (3,479)
Effect on postretirement benefit obligation	$30,159	$(25,578)

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.

The following table sets forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2011 and 2010. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2.

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,707	$—	$ 1,707
Registered investment companies	51,358	—	—	51,358
Total investments at fair value	$51,358	$1,707	$—	$53,065

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Investments:				
Money market funds	$ —	$1,307	$—	$ 1,307
Registered investment companies	51,726	—	—	51,726
Total investments at fair value	$51,726	$1,307	$—	$53,033

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)			
2012	$31,519	$ 3,293	$—	$ 34,812
2013	13,272	3,895	—	17,167
2014	15,271	4,491	—	19,762
2015	16,789	5,026	—	21,815
2016	18,333	5,672	—	24,005
2017-2021	99,139	38,238	—	137,377

Defined Contribution Plans

As of September 30, 2011, 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 Holdings, LLC 401K Profit-Sharing Plan (the AEH 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. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees participate in our defined contribution plan, which was enhanced, effective January 1, 2011. Employees participating in the Pension Account Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

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 $10.2 million, $9.8 million, and $9.3 million for fiscal years 2011, 2010 and 2009. 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 2011, 2010 or 2009. At September 30, 2011 and 2010, the Retirement Savings Plan held 4.5 percent and 4.3 percent of our outstanding common stock.

The AEH 401K Profit-Sharing Plan covers substantially all AEH 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 75 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 four percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEH 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 AEH 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.3 million, $1.3 million and $1.2 million for fiscal years 2011, 2010 and 2009.

10. 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, 2011 and 2010:

	September 30	
	2011	2010
	(In thousands)	
Billed accounts receivable	$216,145	$223,129
Unbilled revenue	48,006	47,423
Other accounts receivable	16,592	15,356
Total accounts receivable	280,743	285,908
Less: allowance for doubtful accounts	(7,440)	(12,701)
Net accounts receivable	$273,303	$273,207

Other current assets

Other current assets as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30 2011	September 30 2010
	(In thousands)	
Assets from risk management activities	$ 18,344	$ 20,575
Deferred gas costs	33,976	22,701
Taxes receivable	9,215	19,382
Current deferred tax asset	76,725	53,926
Prepaid expenses	22,499	24,754
Current portion of leased assets receivable	2,013	2,973
Materials and supplies	4,113	3,940
Assets held for sale	140,571	—
Other	9,015	2,744
Total	$316,471	$150,995

As discussed in Note 6, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "assets held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2011.

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2011 and 2010:

	September 30 2011	September 30 2010
	(In thousands)	
Production plant	$ 7,412	$ 17,360
Storage plant	198,422	193,155
Transmission plant	1,126,509	1,108,398
Distribution plant	4,496,263	4,339,277
General plant	737,850	671,953
Intangible plant	41,096	54,253
	6,607,552	6,384,396
Construction in progress	209,242	157,922
	6,816,794	6,542,318
Less: accumulated depreciation and amortization	(1,668,876)	(1,749,243)
Net property, plant and equipment	$ 5,147,918	$ 4,793,075

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Marketable securities	$ 52,633	$ 41,466
Regulatory assets	278,920	254,809
Deferred financing costs	35,149	35,761
Assets from risk management activities	998	937
Other	16,093	22,403
Total	$383,793	$355,376

Other current liabilities

Other current liabilities as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Customer credit balances and deposits	$106,743	$114,215
Accrued employee costs	38,558	40,642
Deferred gas costs	8,130	43,333
Accrued interest	37,557	42,901
Liabilities from risk management activities	15,453	49,673
Taxes payable	57,853	56,616
Pension and postretirement obligations	33,036	14,815
Regulatory cost of removal accrual	35,078	30,953
Liabilities held for sale	18,445	—
Other	16,710	20,492
Total	$367,563	$413,640

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Postretirement obligations	$202,709	$167,899
Retirement plan obligations	236,227	207,234
Customer advances for construction	13,967	15,466
Regulatory liabilities	13,823	6,112
Asset retirement obligation	13,574	11,432
Uncertain tax positions	—	6,731
Liabilities from risk management activities	78,089	8,924
Other	6,306	6,366
Total	$564,695	$430,164

11. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, granted under the LTIP, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

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

	2011	2010	2009
	(In thousands, except per share data)		
Basic Earnings Per Share from continuing operations			
Income from continuing operations	$198,884	$198,273	$183,299
Less: Income from continuing operations allocated to participating securities	2,077	2,029	1,712
Income from continuing operations available to common shareholders	$196,807	$196,244	$181,587
Basic weighted average shares outstanding	90,201	91,852	91,117
Income from continuing operations per share — Basic	$ 2.18	$ 2.14	$ 1.99
Basic Earnings Per Share from discontinued operations			
Income from discontinued operations	$ 8,717	$ 7,566	$ 7,679
Less: Income from discontinued operations allocated to participating securities	91	77	72
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Basic weighted average shares outstanding	90,201	91,852	91,117
Income from discontinued operations per share — Basic	$ 0.10	$ 0.08	$ 0.09
Net income per share — Basic	$ 2.28	$ 2.22	$ 2.08

Diluted Earnings Per Share from continuing operations			
Income from continuing operations available to common shareholders	$196,807	$196,244	$181,587
Effect of dilutive stock options and other shares	4	5	4
Income from continuing operations available to common shareholders	$196,811	$196,249	$181,591
Basic weighted average shares outstanding	90,201	91,852	91,117
Additional dilutive stock options and other shares	451	570	503
Diluted weighted average shares outstanding	90,652	92,422	91,620
Income from continuing operations per share — Diluted	$ 2.17	$ 2.12	$ 1.98
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Effect of dilutive stock options and other shares	—	—	—
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Basic weighted average shares outstanding	90,201	91,852	91,117
Additional dilutive stock options and other shares	451	570	503
Diluted weighted average shares outstanding	90,652	92,422	91,620
Income from discontinued operations per share — Diluted	$ 0.10	$ 0.08	$ 0.09
Net income per share — Diluted	$ 2.27	$ 2.20	$ 2.07

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal years ended September 30, 2011 and 2010. 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.

12. Income Taxes

The components of income tax expense from continuing operations for 2011, 2010 and 2009 were as follows:

	2011	2010	2009
		(In thousands)	
Current			
Federal	$(11,204)	$(72,234)	$(37,141)
State	6,533	6,179	8,720
Deferred			
Federal	112,612	179,271	134,912
State	5,920	11,429	(8,739)
Investment tax credits	(172)	(283)	(390)
	$113,689	$124,362	$ 97,362

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2011, 2010 and 2009 are set forth below:

	2011	2010	2009
		(In thousands)	
Tax at statutory rate of 35%	$109,401	$112,922	$98,231
Common stock dividends deductible for tax reporting	(1,930)	(1,785)	(1,591)
Penalties	2,294	107	72
Settlement of uncertain tax positions	(4,950)	—	—
State taxes (net of federal benefit)	8,184	11,445	(13)
Other, net	690	1,673	663
Income tax expense	$113,689	$124,362	$97,362

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, 2011 and 2010 are presented below:

	2011	2010
	(In thousands)	
Deferred tax assets:		
Accruals not currently deductible for tax purposes	$ 10,327	$ 9,182
Customer advances	5,271	5,723
Nonqualified benefit plans	43,924	43,427
Postretirement benefits	62,274	57,386
Treasury lock agreements	20,060	3,211
Unamortized investment tax credit	120	183
Tax net operating loss and credit carryforwards	95,293	63,621
Difference between book and tax on mark to market accounting	8,039	2,159
Other, net	3,529	4,559
Total deferred tax assets	248,837	189,451
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,108,063)	(940,914)
Pension funding	(7,533)	(14,936)
Gas cost adjustments	(13,570)	(6,473)
Cost expensed for tax purposes and capitalized for book purposes	(3,039)	(2,330)
Total deferred tax liabilities	(1,132,205)	(964,653)
Net deferred tax liabilities	$ (883,368)	$(775,202)
Deferred credits for rate regulated entities	$ 325	$ 587

At September 30, 2011, we had $10.1 million of federal alternative minimum tax credit carryforwards, $75.2 million of federal net operating loss carryforwards and $9.9 million of state net operating loss carryforwards. The alternative minimum tax credit carryforwards do not expire. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2029. Depending on the jurisdiction in which the state net operating loss was generated, the state net operating loss carryforwards will begin to expire between 2016 and 2029.

At September 30, 2010, we had accrued liabilities associated with uncertain tax positions totaling $6.7 million. During the fiscal year ended September 30, 2011, the IRS completed its audit of fiscal years 2005-2007. All uncertain tax positions were effectively settled upon completion of the audit. As a result of the settlement, we reduced our unrecognized tax benefits by $6.7 million in the second quarter of fiscal 2011. Income tax expense was reduced by $5.0 million in the second quarter due to the realization of the tax positions which were previously uncertain. As of September 30, 2011, we had no liabilities associated with uncertain tax positions.

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. We recognized a tax expense of $0.01 million, $0.5 million and $0.1 million related to penalty and interest expenses during the fiscal years ended September 30, 2011, 2010 and 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 2007.

13. Commitments and Contingencies

Litigation

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On March 30, 2011, we filed a notice of appeal of this ruling. We strongly believe that the trial court erred in not granting our motion to dismiss the lawsuit prior to trial and that the verdict is unsupported by law. After consultation with counsel, we believe that it is probable that any judgment based on this verdict will be overturned on appeal.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We are a party to other litigation and 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, Tennessee, Keokuk, Iowa 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. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa, 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

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2011, AEH was committed to purchase 103.3 Bcf within one year, 46.4 Bcf within one to three years and 0.9 Bcf after three years under indexed contracts. AEH is committed to purchase 4.2 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.49 to $6.36 per Mcf. Purchases under these contracts totaled $1,498.6 million, $1,562.8 million and $1,484.5 million for 2011, 2010 and 2009.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of September 30, 2011 are as follows (in thousands):

2012	$274,985
2013	102,959
2014	82,235
2015	—
2016	—
Thereafter	—
	$460,179

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts as of September 30, 2011 are as follows (in thousands):

2012	$25,362
2013	16,711
2014	9,988
2015	4,130
2016	278
Thereafter	165
	$56,634

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.

Since that time, we have fully cooperated with FERC during this investigation. In August 2011, the FERC issued a Notice of Alleged Violations stating that it preliminarily determined that Atmos Energy Corporation and its subsidiaries, Atmos Energy Marketing, LLC (AEM) and Trans Louisiana Gas Pipeline, Inc. (TLGP) violated Sections 284.8(h)(2) and 1c.1 of the Commission's regulations through flipping and AEM violated the Commission's shipper-must-have-title requirement and the associated FERC gas tariffs of various pipelines.

The Company and FERC are currently involved in settlement discussions. We have accrued what we believe is an adequate amount for the anticipated resolution of this matter.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities in our Mid-Tex Division have agreed to a program of installing 100,000 replacements during the next fiscal year, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing

35,852 lines for a cost of $49.7 million as of September 30, 2011. The program is progressing on schedule for completion in September 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

14. 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, 2011 and 2010, we had receivables of $2.0 million and $7.8 million and recognized income of $0.5 million, $0.9 million and $1.2 million for fiscal years 2011, 2010 and 2009. The future minimum lease payments to be received for each of the five succeeding fiscal years are as follows:

	Minimum Lease Receipts
	(In thousands)
2012	$2,013
Thereafter	—
Total minimum lease receipts	$2,013

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 21 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 and $1.3 million at September 30, 2011 and 2010. Accumulated depreciation for these capital leases totaled $0.9 and $0.8 million at September 30, 2011 and 2010. 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, 2011 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2012	$ 186	$ 17,718
2013	186	16,846
2014	186	16,519
2015	186	15,455
2016	186	14,921
Thereafter	264	118,108
Total minimum lease payments	1,194	$199,567
Less amount representing interest	406	
Present value of net minimum lease payments	$ 788	

Consolidated lease and rental expense amounted to $19.1 million, $16.0 million and $13.6 million for fiscal 2011, 2010 and 2009.

15. 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, 2011, 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. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2011 and 2010.

	September 30, 2011	September 30, 2010
Investment grade	54%	58%
Non-investment grade	46%	42%
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, 2011. 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)]	Nonregulated Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$ 16	$ 16
Non-investment grade counterparties	—	1,081	1,081
	$—	$1,097	$1,097

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

16. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for fiscal 2011, 2010 and 2009 are presented below.

	2011	2010	2009
		(In thousands)	
Cash paid for interest	$157,976	$161,925	$163,554
Cash received for income taxes	$ (8,329)	$(63,677)	$(36,405)

There were no significant noncash investing and financing transactions during fiscal 2011, 2010 and 2009. All cash flows and noncash activities related to our commodity financial instruments are considered as operating activities.

17. 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 three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

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.

Through November 30, 2010, our operations were divided into four segments:

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

As a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- The *natural gas distribution segment*, remains unchanged and includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, remains unchanged and includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services which were previously reported in the natural gas marketing and pipeline, storage and other segments.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. 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. Prior-year amounts have been restated to reflect the new operating segments.

	Year Ended September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,530,980	$ 87,141	$1,729,513	$ —	$4,347,634
Intersegment revenues	883	132,232	295,380	(428,495)	—
	2,531,863	219,373	2,024,893	(428,495)	4,347,634
Purchased gas cost	1,487,499	—	1,959,893	(426,999)	3,020,393
Gross profit	1,044,364	219,373	65,000	(1,496)	1,327,241
Operating expenses					
Operation and maintenance	348,083	70,401	32,308	(1,502)	449,290
Depreciation and amortization	196,909	25,997	4,193	—	227,099
Taxes, other than income	161,371	14,700	2,612	—	178,683
Asset impairments	—	—	30,270	—	30,270
Total operating expenses	706,363	111,098	69,383	(1,502)	885,342
Operating income (loss)	338,001	108,275	(4,383)	6	441,899
Miscellaneous income	16,557	4,715	657	(430)	21,499
Interest charges	115,802	31,432	4,015	(424)	150,825
Income (loss) from continuing operations before income taxes	238,756	81,558	(7,741)	—	312,573
Income tax expense (benefit)	84,755	29,143	(209)	—	113,689
Income (loss) from continuing operations	154,001	52,415	(7,532)	—	198,884
Income from discontinued operations, net of tax	8,717	—	—	—	8,717
Net income (loss)	$ 162,718	$ 52,415	$ (7,532)	$ —	$ 207,601
Capital expenditures	$ 496,899	$118,452	$ 7,614	$ —	$ 622,965

	Year Ended September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,841,768	$ 97,023	$1,781,044	$ —	$4,719,835
Intersegment revenues	870	105,990	365,614	(472,474)	—
	2,842,638	203,013	2,146,658	(472,474)	4,719,835
Purchased gas cost	1,820,627	—	2,032,567	(470,864)	3,382,330
Gross profit	1,022,011	203,013	114,091	(1,610)	1,337,505
Operating expenses					
Operation and maintenance	355,357	72,249	34,517	(1,610)	460,513
Depreciation and amortization	185,147	21,368	5,074	—	211,589
Taxes, other than income	171,338	12,358	4,556	—	188,252
Total operating expenses	711,842	105,975	44,147	(1,610)	860,354
Operating income	310,169	97,038	69,944	—	477,151
Miscellaneous income (expense)	1,567	135	3,859	(5,717)	(156)
Interest charges	118,319	31,174	10,584	(5,717)	154,360
Income from continuing operations before income taxes	193,417	65,999	63,219	—	322,635
Income tax expense	75,034	24,513	24,815	—	124,362
Income from continuing operations	118,383	41,486	38,404	—	198,273
Income from discontinued operations, net of tax	7,566	—	—	—	7,566
Net income	$ 125,949	$ 41,486	$ 38,404	$ —	$ 205,839
Capital expenditures	$ 437,815	$ 95,835	$ 8,986	$ —	$ 542,636

	Year Ended September 30, 2009				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,883,997	$119,427	$1,865,687	$ —	$4,869,111
Intersegment revenues	799	90,231	418,301	(509,331)	—
	2,884,796	209,658	2,283,988	(509,331)	4,869,111
Purchased gas cost	1,887,192	—	2,169,880	(507,639)	3,549,433
Gross profit	997,604	209,658	114,108	(1,692)	1,319,678
Operating expenses					
Operation and maintenance	361,123	85,249	41,368	(2,036)	485,704
Depreciation and amortization	187,050	20,413	4,521	—	211,984
Taxes, other than income	166,854	10,231	3,157	—	180,242
Asset impairments	4,599	602	181	—	5,382
Total operating expenses	719,626	116,495	49,227	(2,036)	883,312
Operating income	277,978	93,163	64,881	344	436,366
Miscellaneous income (expense)	6,002	1,433	6,399	(16,901)	(3,067)
Interest charges	123,863	30,982	14,350	(16,557)	152,638
Income from continuing operations before income taxes	160,117	63,614	56,930	—	280,661
Income tax expense	50,989	22,558	23,815	—	97,362
Income from continuing operations	109,128	41,056	33,115	—	183,299
Income from discontinued operations, net of tax	7,679	—	—	—	7,679
Net income	$ 116,807	$ 41,056	$ 33,115	$ —	$ 190,978
Capital expenditures	$ 379,500	$108,332	$ 21,662	$ —	$ 509,494

The following table summarizes our revenues by products and services for the fiscal year ended September 30. Prior-year amounts have been restated to reflect the new operating segments.

	2011	2010	2009
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,570,723	$1,784,051	$1,768,082
Commercial	698,366	787,433	807,109
Industrial	106,569	110,280	132,487
Public authority and other	69,176	70,402	88,972
Total gas sales revenues	2,444,834	2,752,166	2,796,650
Transportation revenues	59,547	58,511	56,162
Other gas revenues	26,599	31,091	31,185
Total natural gas distribution revenues	2,530,980	2,841,768	2,883,997
Regulated transmission and storage revenues	87,141	97,023	119,427
Nonregulated revenues	1,729,513	1,781,044	1,865,687
Total operating revenues	$4,347,634	$4,719,835	$4,869,111

Balance sheet information at September 30, 2011 and 2010 by segment is presented in the following tables. Prior-year amounts have been restated to reflect the new operating segments.

	September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,248,198	$ 838,302	$ 61,418	$ —	$5,147,918
Investment in subsidiaries	670,993	—	(2,096)	(668,897)	—
Current assets					
Cash and cash equivalents	24,646	—	106,773	—	131,419
Assets from risk management activities	843	—	17,501	—	18,344
Other current assets	655,716	15,413	386,215	(196,154)	861,190
Intercompany receivables	569,898	—	—	(569,898)	—
Total current assets	1,251,103	15,413	510,489	(766,052)	1,010,953
Intangible assets	—	—	207	—	207
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	998	—	—	—	998
Deferred charges and other assets	353,960	18,028	10,807	—	382,795
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,255,421	$ 265,102	$405,891	$ (670,993)	$2,255,421
Long-term debt	2,205,986	—	131	—	2,206,117
Total capitalization	4,461,407	265,102	406,022	(670,993)	4,461,538
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	387,691	—	—	(181,295)	206,396
Liabilities from risk management activities	11,916	—	3,537	—	15,453
Other current liabilities	474,783	10,369	170,926	(12,763)	643,315
Intercompany payables	—	543,084	26,814	(569,898)	—
Total current liabilities	876,693	553,453	201,408	(763,956)	867,598
Deferred income taxes	789,649	173,351	(2,907)	—	960,093
Noncurrent liabilities from risk management activities	67,862	—	10,227	—	78,089
Regulatory cost of removal obligation	428,947	—	—	—	428,947
Deferred credits and other liabilities	473,602	12,218	786	—	486,606
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871

	September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$3,959,112	$748,947	$ 85,016	$ —	$4,793,075
Investment in subsidiaries	620,863	—	(2,096)	(618,767)	—
Current assets					
Cash and cash equivalents	31,952	—	100,000	—	131,952
Assets from risk management activities	2,219	—	18,356	—	20,575
Other current assets	528,655	19,504	325,348	(150,842)	722,665
Intercompany receivables	546,313	—	—	(546,313)	—
Total current assets	1,109,139	19,504	443,704	(697,155)	875,192
Intangible assets	—	—	834	—	834
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	47	—	890	—	937
Deferred charges and other assets	324,707	13,037	16,695	—	354,439
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,178,348	$212,687	$408,176	$ (620,863)	$2,178,348
Long-term debt	1,809,289	—	262	—	1,809,551
Total capitalization	3,987,637	212,687	408,438	(620,863)	3,987,899
Current liabilities					
Current maturities of long-term debt	360,000	—	131	—	360,131
Short-term debt	258,488	—	—	(132,388)	126,100
Liabilities from risk management activities	48,942	—	731	—	49,673
Other current liabilities	473,076	10,949	162,508	(16,358)	630,175
Intercompany payables	—	543,007	3,306	(546,313)	—
Total current liabilities	1,140,506	553,956	166,676	(695,059)	1,166,079
Deferred income taxes	691,126	142,337	(4,335)	—	829,128
Noncurrent liabilities from risk management activities	2,924	—	6,000	—	8,924
Regulatory cost of removal obligation	350,521	—	—	—	350,521
Deferred credits and other liabilities	413,416	4,849	2,975	—	421,240
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791

18. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. Prior-period amounts have been restated to reflect continuing operations. 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 2011:				
Operating revenues				
Natural gas distribution	$ 703,462[1]	$1,077,414[2]	$ 407,031	$ 343,956
Regulated transmission and storage	49,007	54,976	53,570	61,820
Nonregulated	475,640	583,531	491,285	474,437
Intersegment eliminations	(94,847)	(134,424)	(108,271)	(90,953)
	1,133,262	1,581,497	843,615	789,260
Gross profit	364,724[1]	453,668[2]	266,805	242,044
Operating income	155,289[1]	211,199[2]	34,078	41,333
Income (loss) from continuing operations	71,100	128,160	(1,474)	1,098
Income from discontinued operations	2,897	4,049	908	863
Net income (loss)	73,997	132,209	(566)	1,961
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.78	$ 1.41	$ (0.02)	$ 0.01
Income per share from discontinued operations	$ 0.03	$ 0.04	$ 0.01	$ 0.01
Net income (loss) per share — basic	$ 0.81	$ 1.45	$ (0.01)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.78	$ 1.41	$ (0.02)	$ 0.01
Income per share from discontinued operations	$ 0.03	$ 0.04	$ 0.01	$ 0.01
Net income (loss) per share — diluted	$ 0.81	$ 1.45	$ (0.01)	$ 0.02

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2010:				
Operating revenues				
Natural gas distribution	$ 781,841[3]	$1,333,872[4]	$ 396,319	$ 330,606[5]
Regulated transmission and storage	46,860	55,181	44,957	56,015
Nonregulated	548,016	677,032	427,405	494,205
Intersegment eliminations	(104,918)	(157,935)	(107,376)	(102,245)
	1,271,799	1,908,150	761,305	778,581
Gross profit	403,003[3]	445,444[4]	247,666	241,392[5]
Operating income	186,598[3]	219,757[4]	32,259	38,537[5]
Income (loss) from continuing operations	90,975	111,283	(4,229)	244
Income from discontinued operations	2,355	2,843	1,075	1,293
Net income (loss)	93,330	114,126	(3,154)	1,537
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.97	$ 1.19	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.03	0.03	$ 0.01	$ 0.02
Net income (loss) per share — basic	$ 1.00	$ 1.22	$ (0.03)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.97	$ 1.19	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.03	$ 0.03	$ 0.01	$ 0.02
Net income (loss) per share — diluted	$ 1.00	$ 1.22	$ (0.03)	$ 0.02

(1) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $23.7 million, $8.8 million and $4.8 million.

(2) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $35.8 million, $11.2 million and $6.7 million.

(3) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $21.1 million, $7.8 million and $4.0 million.

(4) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $32.1 million, $8.9 million and $4.8 million.

(5) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $7.7 million, $5.2 million and $1.7 million.

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, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

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, 2011, 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/ KIM R. COCKLIN	/s/ FRED E. MEISENHEIMER
Kim R. Cocklin President and Chief Executive Officer	Fred E. Meisenheimer Senior Vice President and Chief Financial Officer

November 22, 2011

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, 2011, 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, 2011, 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, 2011 and 2010, and the related statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2011 of Atmos Energy Corporation and our report dated November 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 22, 2011

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, 2011 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 8, 2012. Information regarding executive officers is reported below:

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2011, 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	64	14	Executive Chairman of the Board
Kim R. Cocklin	60	5	President and Chief Executive Officer
Louis P. Gregory	56	11	Senior Vice President and General Counsel
Michael E. Haefner	51	3	Senior Vice President, Human Resources
Fred E. Meisenheimer	67	11	Senior Vice President and Chief Financial Officer

Robert W. Best was named Executive Chairman of the Board on October 1, 2010. From March 1997 through September 2008, Mr. Best served the Company as Chairman of the Board, President and Chief Executive Officer. From October 1, 2008 through September 30, 2010, Mr. Best continued to serve the Company as Chairman of the Board and Chief Executive Officer.

Kim R. Cocklin was named President and Chief Executive Officer effective October 1, 2010. Mr. Cocklin joined the Company in June 2006 and served as President and Chief Operating Officer of the Company from October 1, 2008 through September 30, 2010, after having served as Senior Vice President, Regulated Operations from October 2006 through September 2008. Mr. Cocklin was Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 through May 2006. Mr. Cocklin was appointed to the Board of Directors on November 10, 2009.

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.

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, interim Chief Financial Officer in January 2009 and Treasurer from November 2009 through February 2011.

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 8, 2012.

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 8, 2012.

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 8, 2012. 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 8, 2012.

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 8, 2012.

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 10.6(a) through 10.14 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 22, 2011

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Kim R. Cocklin 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/ KIM R. COCKLIN Kim R. Cocklin	President, Chief Executive Officer and Director	November 22, 2011
/s/ FRED E. MEISENHEIMER Fred E. Meisenheimer	Senior Vice President and Chief Financial Officer	November 22, 2011
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Vice President and Controller (Principal Accounting Officer)	November 22, 2011
/s/ ROBERT W. BEST Robert W. Best	Executive Chairman of the Board	November 22, 2011
/s/ RICHARD W. DOUGLAS Richard W. Douglas	Director	November 22, 2011
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 22, 2011
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 22, 2011
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 22, 2011
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 22, 2011
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 22, 2011
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 22, 2011
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 22, 2011
/s/ RICHARD WARE II Richard Ware II	Director	November 22, 2011

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2011

	Balance at beginning of period	Additions: Charged to Cost & Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		(In thousands)			
2011					
Allowance for doubtful accounts	$12,701	$2,201	$—	$ 7,462[1]	$ 7,440
2010					
Allowance for doubtful accounts	$11,478	$7,694	$—	$ 6,471[1]	$12,701
2009					
Allowance for doubtful accounts	$15,301	$7,769	$—	$11,592[1]	$11,478

[1] Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Acquisition	
2.1	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Midstates) Corp. as Buyer, dated as of May 12, 2011	Exhibit 2.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation — Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation — Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 3, 2010)	Exhibit 3.2 of Form 8-K dated February 3, 2010 (File No. 1-10042)
	Instruments Defining Rights of Security Holders	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit 4.1 to Form 10-K for fiscal year ended September 30, 2010 (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 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(c)	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(d)	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(e)	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(f)	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)
4.7(g)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 10, 2011 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	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)
10.2	Revolving Credit Agreement, dated as of May 2, 2011 among Atmos Energy Corporation, the Lenders from time to time parties thereto, The Royal Bank of Scotland plc as Administrative Agent, Crédit Agricole Corporate and Investment Bank as Syndication Agent, Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A. as Co-Documentation Agents	Exhibit 10.1 to Form 8-K dated May 2, 2011 (File No. 1-10042)
10.3(a)	Fifth Amended and Restated Credit Agreement, dated as of December 8, 2010, among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank, a swing line bank and a bank; Société Générale as co-syndication agent, an issuing bank and a bank and The Royal Bank of Scotland plc, as co-syndication agent and a bank; and Natixis, New York Branch, Crédit Agricole Corporate and Investment Bank, and Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A. as co-documentation agents and the other financial institutions that become parties thereto	Exhibit 10.1 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.3(b)	Third Amended and Restated Intercreditor Agreement, dated as of December 8, 2010, (as amended, supplemented and otherwise modified from time to time, the "Agreement"), among BNP Paribas, a bank organized under the laws of France, in its capacity as Collateral Agent (together with its successors and assigns in such capacity, the "Agent") for the Banks thereinafter referred to, and each bank and other financial institution which is now or hereafter a party to the Agreement in its capacity as a Bank and, as applicable, as a Swap Bank (collectively, the "Swap Banks") and/or a Physical Trade Bank (collectively, the "Physical Trade Banks")	Exhibit 10.2 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.4(a)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Master Confirmation dated July 1, 2010	Exhibit 10.6(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.4(b)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Supplemental Confirmation dated July 1, 2010	Exhibit 10.6(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.5	Guaranty of Algonquin Power & Utilities Corp. dated May 12, 2011	Exhibit 10.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.6(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.6(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.7(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)
10.7(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)
10.8(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)
10.8(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)
10.9(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)
10.9(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of November 12, 2009)	Exhibit 10.10(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(c)*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan, Effective Date August 5, 2009	Exhibit 10.10(c) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(d)*	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)
10.9(e)*	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)
10.10(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)
10.10(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)
10.10(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)
10.11*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2010	Exhibit 10.12 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.12*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan, Amended and Restated as of October 1, 2009	Exhibit 10.13 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 10, 2011)	Exhibit 99.1 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.13(b)*	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)
10.13(c)*	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)
10.13(d)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 99.4 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.13(e)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 99.5 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.14*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	
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, 2011
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
101.INS	XBRL Instance Document***	
101.SCH	XBRL Taxonomy Extension Schema***	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase***	
101.DEF	XBRL Taxonomy Extension Definition Linkbase***	
101.LAB	XBRL Taxonomy Extension Labels Linkbase***	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase***	

* 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.

*** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

CASE NO. 2013-00148
FR 16(12)(p) ATTACHMENT 3

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

Form 8-K

Current Report

**Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934**

**February 13, 2013
Date of Report (Date of earliest event reported)**

ATMOS ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

TEXAS AND VIRGINIA	**1-10042**	**75-1743247**
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

1800 THREE LINCOLN CENTRE, 5430 LBJ FREEWAY, DALLAS, TEXAS	**75240**
(Address of Principal Executive Offices)	(Zip Code)

(972) 934-9227
(Registrant's Telephone Number, Including Area Code)

Not Applicable
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 40.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 5.07. Submission of Matters to a Vote of Security Holders.

At the company's 2013 annual meeting of shareholders on February 13, 2013, of the 90,461,872 total shares of our common stock outstanding and entitled to vote, a total of 80,969,691 shares were represented, constituting an 89.5% quorum. The final results for each of the matters submitted to a vote of our shareholders at the annual meeting are as follows:

Proposal No. 1 **:** All of the board's nominees for director were elected by our shareholders to serve until the company's 2014 annual meeting of shareholders or until their respective successors are elected and qualified, with the vote totals as set forth in the table below:

Nominee	For	Against	Abstain	Broker Non-Votes
Robert W. Best	63,622,479	1,421,869	143,337	15,782,006
Kim R. Cocklin	64,562,520	481,496	143,669	15,782,006
Richard W. Douglas	64,602,064	428,057	157,564	15,782,006
Ruben E. Esquivel	64,628,289	409,854	149,542	15,782,006
Richard K. Gordon	64,497,037	532,289	158,359	15,782,006
Robert C. Grable	64,646,768	377,672	163,245	15,782,006
Thomas C. Meredith	63,605,752	1,428,341	153,592	15,782,006
Nancy K. Quinn	64,662,913	374,870	149,902	15,782,006
Richard A. Sampson	64,650,181	369,988	167,516	15,782,006
Stephen R. Springer	64,384,250	637,343	166,092	15,782,006
Richard Ware II	63,379,584	1,631,463	176,638	15,782,006

Proposal No. 2: Our shareholders approved an amendment to our Annual Incentive Plan for Management, with the vote totals as set forth in the table below:

For	Against	Abstain	Broker Non-Votes
63,002,058	1,619,920	565,707	15,782,006

Proposal No. 3 **:** The appointment of Ernst & Young LLP as the company's independent registered public accounting firm for fiscal 2013 was ratified by our shareholders, with the vote totals as set forth in the table below:

For	Against	Abstain	Broker Non-Votes
79,293,263	1,457,776	218,652	-0-

Proposal No. 4: Our shareholders approved, on an advisory (non-binding) basis, the compensation of our named executive officers for fiscal 2012, with the vote totals as set forth in the table below:

For	Against	Abstain	Broker Non-Votes
62,585,802	2,101,469	500,414	15,782,006

Item 8.01. Other Events.

On February 13, 2013, the independent directors of the company's board designated director Nancy K. Quinn, chair of the Audit Committee, as Lead Director.

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

DATE: February 15, 2013

By: /s/ LOUIS P. GREGORY
Louis P. Gregory
Senior Vice President, General Counsel and Corporate Secretary

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

Form 8-K

Current Report

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

February 6, 2013
Date of Report (Date of earliest event reported)

ATMOS ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

TEXAS AND VIRGINIA	1-10042	75-1743247
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

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☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02. Results of Operations and Financial Condition.

On Wednesday, February 6, 2013, Atmos Energy Corporation (the "Company") issued a news release in which it reported the Company's financial results for the first quarter of the 2013 fiscal year, which will end September 30, 2013, and stated that certain of its officers would discuss such financial results in a conference call on Thursday, February 7, 2013 at 10:00 a.m. Eastern Time. In the release, the Company also announced that the call would be webcast live and that slides for the webcast would be available on its website for all interested parties.

A copy of the news release is furnished as Exhibit 99.1. The information furnished in this Item 2.02 and in Exhibit 99.1 shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section, nor shall such information be deemed to be incorporated by reference into any of the Company's filings under the Securities Act of 1933 or the Securities Exchange Act of 1934.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits

99.1 News Release dated February 6, 2013 (furnished under Item 2.02)

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

DATE: February 6, 2013

By: /s/ LOUIS P. GREGORY
Louis P. Gregory
Senior Vice President, General Counsel
and Corporate Secretary

INDEX TO EXHIBITS

Exhibit Number	Description
99.1	News Release dated February 6, 2013 (furnished under Item 2.02)

Exhibit 99.1

News Release

Analysts and Media Contact:
Susan Giles (972) 855-3729

Atmos Energy Corporation Reports Earnings for Fiscal 2013 First Quarter;
Company Affirms Fiscal 2013 Guidance

DALLAS (February 6, 2013)—Atmos Energy Corporation (NYSE: ATO) today reported consolidated results for its fiscal 2013 first quarter ended December 31, 2012.

- Fiscal 2013 first quarter consolidated results, excluding net unrealized margins were \$67.7 million, or \$0.74 per diluted share, compared with results, excluding net unrealized margins of \$55.5 million, or \$0.61 per diluted share in the prior-year quarter.
- After including noncash, unrealized net gains of \$12.8 million, or \$0.14 per diluted share, fiscal 2013 first quarter net income was \$80.5 million, or \$0.88 per diluted share. Net income was \$68.5 million, or \$0.75 per diluted share in the prior-year quarter, after including unrealized net gains of \$13.0 million or \$0.14 per diluted share.
- Net income from discontinued operations was \$3.1 million, or \$0.03 per diluted share for the three months ended December 31, 2012, compared with \$6.1 million, or \$0.07 per diluted share in the prior-year quarter.
- Atmos Energy expects fiscal 2013 earnings to be at the higher end of the previously announced guidance range of \$2.40 and \$2.50 per diluted share, excluding unrealized margins and the gain on the sale of the company's Georgia operations.

"Constructive rate outcomes in a number of our jurisdictions and changes in rate design in our Mid-Tex and West Texas Divisions have further enhanced the stability and predictability of our regulated earnings stream, as well as provided greater certainty for our customers, whose gas service costs will be spread more evenly over the year," said Kim Cocklin, president and chief executive officer of Atmos Energy Corporation.

Results for the Quarter Ended December 31, 2012

Natural gas distribution gross profit, excluding discontinued operations, decreased \$4.0 million to \$279.6 million for the first quarter of fiscal 2013, compared with \$283.6 million in the prior-year quarter. The decrease in gross profit was primarily due to a \$4.6 million net decrease in rate adjustments due largely to the rate design changes ordered in the recent Mid-Tex and West Texas Divisions rate cases. The new rate design includes an increase in the monthly base customer charge and a decrease in the commodity charge applied to consumption. As a result, margins earned during the first and second fiscal quarters are expected to be lower than in previous periods, while margins in the third and fourth fiscal quarters are expected to be higher than in previous periods. Additionally, revenue-related taxes decreased about $2.7 million, primarily due to lower revenues in both the Mid-Tex and West Texas Divisions. These decreases were partially offset by a $2.4 million increase from colder weather, primarily in the Mid-Tex Division.

Regulated transmission and storage gross profit increased $3.9 million to $60.7 million for the quarter ended December 31, 2012, compared with $56.8 million in the prior-year quarter. This increase is primarily the result of increased revenue from the Gas Reliability Infrastructure Program (GRIP) filing that became effective in April 2012.

Nonregulated gross profit increased $7.1 million to $22.5 million for the first quarter of fiscal 2013, compared with $15.4 million for the prior-year quarter. Realized margins for gas delivery, storage and transportation services and other services decreased $0.7 million quarter-over-quarter, primarily due to a seven percent decrease in consolidated sales volumes, which was largely attributable to warmer weather. Asset optimization margins increased $6.5 million from the prior-year quarter, primarily due to smaller losses incurred from the settlement of financial positions, partially offset by higher storage demand fees. Additionally, realized asset optimization margins in the prior-year quarter included a $1.7 million charge to write down to market certain natural gas inventory that no longer qualified for fair value hedge accounting.

Consolidated operation and maintenance expense, excluding discontinued operations, for the first quarter of fiscal 2013, was $106.5 million, compared with $114.6 million for the prior-year quarter. The $8.1 million quarter-over-quarter decrease resulted primarily from the establishment of regulatory assets for $3.0 million of certain current-quarter costs, a $2.9 million decrease in legal costs and a $1.1 million decrease due to increased capital spending in the current quarter.

Interest charges for the first quarter of fiscal 2013 were $30.5 million, compared with $35.7 million for the prior-year quarter. The $5.2 million quarter-over-quarter decrease resulted primarily from interest capitalized related to Rule 8.209 spending in the current quarter and the early redemption of the 5.125% $250 million senior notes due January 2013, with funds borrowed under a $260 million short-term debt facility in August 2012.

The debt capitalization ratio at December 31, 2012, was 53.5 percent, compared with 51.7 percent at September 30, 2012 and 53.4 percent at December 31, 2011. At December 31, 2012, there was $830.9 million of short-term debt outstanding, compared with $570.9 million at September 30, 2012 and $390.0 million at December 31, 2011. The short-term debt balance at December 31, 2012 included $260 million outstanding under a short-term facility used to redeem the 5.125% $250 million senior notes in August 2012.

For the quarter ended December 31, 2012, the company generated $29.9 million in operating cash flow, a $45.1 million increase compared with the quarter ended December 31, 2011. The increase primarily reflects the timing of customer collections and vendor payments, as well as the effect of a decrease in the amount of cash used to inject gas into storage, primarily in the company's nonregulated segment.

Capital expenditures increased to $190.0 million for the quarter ended December 31, 2012, compared with $154.4 million in the prior-year quarter. The $35.6 million increase primarily reflects Rule 8.209 spending in the Mid-Tex Division of the natural gas distribution segment and for the Line W and Line WX pipeline expansion projects in the regulated transmission and storage segment.

Outlook

The leadership of Atmos Energy remains focused on enhancing shareholder value by delivering consistent earnings growth. Atmos Energy expects fiscal 2013 earnings to be at the higher end of the previously announced range of $2.40 to $2.50 per diluted share, excluding unrealized margins and the gain on the sale of the company's Georgia operations. Net income from regulated operations is expected to be in the range of $211 million to $219 million, while net income from nonregulated operations is expected to be in the range of $9 million to $11 million. Capital expenditures for fiscal 2013 are expected to range between $770 million to $790 million.

Conference Call to be Webcast February 7, 2013

Atmos Energy will host a conference call with financial analysts to discuss the financial results for the fiscal 2013 first quarter on Thursday, February 7, 2013, at 10 a.m. Eastern Time. The telephone number is 877-485-3107. The conference call will be webcast live on the Atmos Energy website at www.atmosenergy.com . A playback of the call will be available on the website later that day. Kim Cocklin, president and chief executive officer and Bret Eckert, senior vice president and chief financial officer will participate in the conference call.

Highlights and Recent Developments

Atmos Energy Completes Successful Senior Note Offering

On January 11, 2013, Atmos Energy completed the public offering of $500 million 4.15% Senior Notes due 2043. The company used approximately $494 million of net proceeds from this offering to repay a total of $260 million borrowed under a short-term financing facility that was scheduled to mature on February 1, 2013 and for general corporate purposes, including the repayment of working capital borrowings pursuant to the company's commercial paper program.

Charles K. Vaughan Retires from Board of Directors

On January 3, 2013, Atmos Energy announced that Charles K. Vaughan had retired from the company's board of directors, effective December 27, 2012. Subsequent to his retirement, the board appointed Vaughan as an honorary director, effective January 1, 2013.

Amendment of Credit Facility

On December 7, 2012, Atmos Energy amended the company's existing $750 million revolving credit agreement, primarily to increase the lenders' commitment from $750 million to $950 million, while retaining the accordion feature that would allow an increase in commitments up to $1.2 billion and allow the company to obtain same-day funding on base rate loans.

Termination of Atmos Energy Marketing Credit Agreement

On December 5, 2012, Atmos Energy Marketing, LLC (AEM), an indirect wholly-owned subsidiary of the company, terminated its $200 million committed and secured credit facility, which was due to expire on December 3, 2014.

Railroad Commission of Texas Issues Final Order

On December 4, 2012, the Railroad Commission of Texas (RRC) issued a final order in the rate case for the Mid-Tex Division (Division) of Atmos Energy. The order authorized an increase in annual margin of about $29.6 million and a net decrease in annual depreciation rates of approximately $13.0 million, generating a net increase in the Division's annual operating income of about $42.6 million. The order also authorized a return on equity of 10.5 percent, a rate base of $1.513 billion and an increase in the monthly residential customer charge to $17.70. The new rates went into effect January 1, 2013.

This news release should be read in conjunction with the attached unaudited financial information.

Forward-Looking Statements

The matters discussed in this news release 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 news release are forward-looking statements made in good faith by the company and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this news release or in any of the company's other 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 discussed in this news release, including the risks and uncertainties relating to regulatory trends and decisions, the company's ability to continue to access the capital markets and the other factors discussed in the company's reports filed with the Securities and Exchange Commission. These factors include the risks and uncertainties discussed in the company's Annual Report on Form 10-K for the fiscal year ended September 30, 2012. Although the company believes these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. The company undertakes no obligation to update or revise forward-looking statements, whether as a result of new information, future events or otherwise.

About Atmos Energy

Atmos Energy Corporation, headquartered in Dallas, is one of the country's largest natural-gas-only distributors, serving over three million natural gas distribution customers in over 1,400 communities in nine states from the Blue Ridge Mountains in the East to the Rocky Mountains in the West. Atmos Energy also provides natural gas marketing and procurement services to industrial, commercial and municipal customers primarily in the Midwest and Southeast and manages company-owned natural gas pipeline and storage assets, including one of the largest intrastate natural gas pipeline systems in Texas. For more information, visit www.atmosenergy.com .

Atmos Energy Corporation
Financial Highlights (Unaudited)

Statements of Income (000s except per share)	Three Months Ended December 31 2012	2011	Percentage Change
Gross Profit:			
Natural gas distribution segment	$279,631	$283,595	(1)%
Regulated transmission and storage segment	60,681	56,759	7%
Nonregulated segment	22,459	15,405	46%
Intersegment eliminations	(409)	(367)	(11)%
Gross profit	362,362	355,392	2%
Operation and maintenance expense	106,527	114,644	(7)%
Depreciation and amortization	59,579	58,366	2%
Taxes, other than income	41,334	42,911	(4)%
Total operating expenses	207,440	215,921	(4)%
Operating income	154,922	139,471	11%
Miscellaneous income (expense)	698	(2,016)	135%
Interest charges	30,522	35,726	(15)%
Income from continuing operations before income taxes	125,098	101,729	23%
Income tax expense	47,750	39,345	21%
Income from continuing operations	77,348	62,384	24%
Income from discontinued operations, net of tax	3,117	6,123	(49)%
Net income	$ 80,465	$ 68,507	17%
Basic earnings per share			
Income per share from continuing operations	$ 0.85	$ 0.68	
Income per share from discontinued operations	0.04	0.07	
Net income per share – basic	$ 0.89	$ 0.75	
Diluted earnings per share			
Income per share from continuing operations	$ 0.85	$ 0.68	
Income per share from discontinued operations	0.03	0.07	
Net income per share – diluted	$ 0.88	$ 0.75	
Cash dividends per share	$ 0.350	$ 0.345	
Weighted average shares outstanding:			
Basic	90,359	90,254	
Diluted	91,309	90,546	

Summary Net Income (Loss) by Segment (000s)	Three Months Ended December 31 2012	2011	Percentage Change
Natural gas distribution – continuing operations	$53,093	$44,501	19%
Natural gas distribution – discontinued operations	3,117	6,123	(49)%
Regulated transmission and storage	16,105	13,414	20%
Nonregulated	(4,603)	(8,501)	46%
Unrealized margins, net of tax	12,753	12,970	(2)%
Consolidated net income	$80,465	$68,507	17%

Atmos Energy Corporation
Financial Highlights, continued (Unaudited)

Discontinued Operations (000s)	Three Months Ended December 31 2012	Three Months Ended December 31 2011
Operating revenues	$16,284	$40,630
Purchased gas cost	8,967	24,640
Gross profit	7,317	15,990
Operating expenses	2,820	6,728
Operating income	4,497	9,262
Other nonoperating income	348	377
Income from discontinued operations before income taxes	4,845	9,639
Income tax expense	1,728	3,516
Net income from discontinued operations	$ 3,117	$ 6,123

Atmos Energy Corporation
Financial Highlights, continued (Unaudited)

Condensed Balance Sheets (000s)	December 31, 2012	September 30, 2012
Net property, plant and equipment	$5,595,294	$5,475,604
Cash and cash equivalents	124,601	64,239
Accounts receivable, net	500,863	234,526
Gas stored underground	274,126	256,415
Other current assets	265,044	272,782
Total current assets	1,164,634	827,962
Goodwill and intangible assets	740,836	740,847
Deferred charges and other assets	463,454	451,262
	$7,964,218	$7,495,675
Shareholders' equity	$2,424,005	$2,359,243
Long-term debt	1,956,376	1,956,305
Total capitalization	4,380,381	4,315,548
Accounts payable and accrued liabilities	367,312	215,229
Other current liabilities	446,717	489,665
Short-term debt	830,891	570,929
Current maturities of long-term debt	131	131
Total current liabilities	1,645,051	1,275,954
Deferred income taxes	1,066,273	1,015,083
Deferred credits and other liabilities	872,513	889,090
	$7,964,218	$7,495,675

Atmos Energy Corporation
Financial Highlights, continued (Unaudited)

Condensed Statements of Cash Flows (000s)	Three Months Ended December 31 2012	2011
Cash flows from operating activities		
Net income	$ 80,465	$ 68,507
Depreciation and amortization	60,628	60,811
Deferred income taxes	45,951	40,042
Other	3,242	4,692
Changes in assets and liabilities	(160,428)	(189,343)
Net cash provided (used) by operating activities	29,858	(15,291)
Cash flows from investing activities		
Capital expenditures	(190,027)	(154,394)
Other, net	(1,273)	(1,080)
Net cash used in investing activities	(191,300)	(155,474)
Cash flows from financing activities		
Net increase in short-term debt	256,933	173,905
Repayment of long-term debt	—	(2,303)
Cash dividends paid	(31,992)	(31,517)
Repurchase of common stock	—	(12,535)
Repurchase of equity awards	(3,124)	(3,120)
Issuance of common stock	(13)	76
Net cash provided by financing activities	221,804	124,506
Net increase (decrease) in cash and cash equivalents	60,362	(46,259)
Cash and cash equivalents at beginning of period	64,239	131,419
Cash and cash equivalents at end of period	$ 124,601	$ 85,160

Statistics, including discontinued operations	Three Months Ended December 31 2012	2011
Consolidated natural gas distribution throughput (MMcf as metered)	113,699	121,748
Consolidated regulated transmission and storage transportation volumes (MMcf)	108,743	105,037
Consolidated nonregulated delivered gas sales volumes (MMcf)	84,718	90,870
Natural gas distribution meters in service	3,137,298	3,203,008
Natural gas distribution average cost of gas	$ 4.93	$ 4.78
Nonregulated net physical position (Bcf)	25.8	35.6

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

Form 8-K

Current Report

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

January 25, 2013
Date of Report (Date of earliest event reported)

ATMOS ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

TEXAS AND VIRGINIA	1-10042	75-1743247
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

1800 THREE LINCOLN CENTRE, 5430 LBJ FREEWAY, DALLAS, TEXAS	75240
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Item 8.01. Other Events.

In an opinion handed down on January 25, 2013, the Kentucky Court of Appeals overturned a $28.45 million jury verdict returned against Atmos Energy Corporation and two of our subsidiaries in a lawsuit filed in September 2009 in the Circuit Court of Edmonson County, Kentucky arising out of the Park City gas gathering project. The dispute which gave rise to the litigation involved the amount of royalties due from a third party producer to landowners for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners.

In a unanimous decision by a three-judge panel, the Court of Appeals reversed the claims asserted against Atmos Energy and our subsidiaries by the landowners and the investors/working interest owners. The Court of Appeals concluded that all of the claims that Atmos Energy and our subsidiaries appealed should have been dismissed by the trial court as a matter of law. The Court of Appeals let stand the jury verdict on one claim that Atmos Energy and our subsidiaries chose not to appeal, which was a trespass claim. The jury had awarded a total of $10,000 in compensatory damages to one landowner on that claim. The Court of Appeals vacated all of the other damages awarded by the jury and remanded the case to the trial court for a new trial, solely on the issue of whether punitive damages should be awarded to that landowner and, if so, in what amount. The landowners and the investors/working interest owners may seek discretionary review from the Supreme Court of Kentucky. The decision of the Court of Appeals will not become final until that process is completed.

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

DATE: January 29, 2013

By: /s/ LOUIS P. GREGORY
Louis P. Gregory
Senior Vice President, General Counsel
and Corporate Secretary

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

Form 8-K

Current Report

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January 11, 2013
Date of Report (Date of earliest event reported)

ATMOS ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

TEXAS AND VIRGINIA	**1-10042**	**75-1743247**
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☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 1.01. Entry into a Material Definitive Agreement.

On January 11, 2013, Atmos Energy Corporation ("Atmos Energy") completed a public offering of $500,000,000 aggregate principal amount of its 4.15% Senior Notes due 2043 (the "Notes"). The offering has been registered under the Securities Act of 1933, as amended (the "Securities Act"), pursuant to a registration statement on Form S-3 (Registration No. 333-165818) of Atmos Energy (the "Registration Statement"), and the prospectus supplement dated January 8, 2013, which was filed with the Securities and Exchange Commission pursuant to Rule 424(b) of the Securities Act on January 9, 2013. Atmos Energy received net proceeds from the offering, after the underwriting discount and estimated offering expenses, of approximately $494 million.

The Notes were issued pursuant to an indenture dated as of March 26, 2009 (the "Base Indenture") between Atmos Energy and U.S. Bank National Association, as trustee (the ("Trustee"), and an officers' certificate delivered to the Trustee pursuant to Section 301 of the Base Indenture (the "Officers' Certificate"); the Base Indenture, as modified by the Officers' Certificate, is referred to herein as the "Indenture." The Notes are represented by a global security executed by Atmos Energy on January 11, 2013 (the "Global Security") and are unsecured obligations ranking equally with all of Atmos Energy's existing and future senior indebtedness and are senior in right of payment to any future indebtedness that is subordinated to the Notes. The Notes bear interest at an annual rate of 4.15%, payable by Atmos Energy on January 15 and July 15 of each year, beginning on July 15, 2013, and mature on January 15, 2043. Atmos Energy may redeem the Notes at its option at any time, in whole or in part, at a redemption price calculated in accordance with the Indenture.

The Indenture includes covenants that limit the ability of Atmos Energy and its restricted subsidiaries (as defined) to, among other things, (i) create specified liens, (ii) engage in specified sale and leaseback transactions, (iii) consolidate or merge with or into other companies or (iv) sell all or substantially all of Atmos Energy's assets. The restrictive covenants are subject to a number of exceptions and qualifications set forth in the Indenture. The Indenture provides for events of default, including (i) interest payment defaults, (ii) breaches of covenants, (iii) certain payment defaults at final maturity or acceleration of other indebtedness and (iv) the occurrence of events of bankruptcy, insolvency or reorganization. If any event of default occurs and is continuing, subject to certain exceptions, the Trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Notes may declare all the Notes to be due and payable immediately, together with any accrued and unpaid interest.

The above descriptions are qualified in their entirety by reference to the text of the Base Indenture, the Officers' Certificate and the Global Security. The Base Indenture has been previously filed, and the Officers' Certificate and Global Security are filed as Exhibits 4.1 and 4.2 to this Current Report on Form 8-K, respectively, and are each incorporated herein by reference.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*

Exhibit Number	Description
4.1	Officers' Certificate dated January 11, 2013
4.2	Global Security for the 4.15% Senior Notes due 2043

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

DATE: January 15, 2013

By: /s/ LOUIS P. GREGORY
Louis P. Gregory
Senior Vice President, General Counsel
and Corporate Secretary

INDEX TO EXHIBITS

Exhibit Number	Description
4.1	Officers' Certificate dated January 11, 2013
4.2	Global Security for the 4.15% Senior Notes due 2043

Exhibit 4.1

ATMOS ENERGY CORPORATION

Officers' Certificate Pursuant to Section 301 of the Indenture

January 11, 2013

Each of the undersigned, Bret J. Eckert, Senior Vice President and Chief Financial Officer, and Louis P. Gregory, Senior Vice President, General Counsel and Corporate Secretary of Atmos Energy Corporation (the "Company") certifies, pursuant to the authority delegated to each of them, as an officer of the Company, pursuant to the resolutions adopted by the board of directors of the Company (the "Board") on November 6, 2012 (copies of which resolutions are attached hereto as Exhibit I), that pursuant to Section 301 of the Indenture dated as of March 26, 2009 (the "Indenture") between the Company and U.S. Bank National Association, as trustee (the "Trustee"), a series of debt securities of the Company is hereby established with the following terms and provisions (unless otherwise defined herein, capitalized terms used herein have the meaning given thereto in the Indenture):

1. The title of the series of the securities is the 4.15% Senior Notes due 2043 (the "Notes").

2. The Notes are unsubordinated and will rank equally with all of the Company's other unsecured and unsubordinated debt. Subordinated debt will rank junior to the Notes and the Company's other senior debt.

3. The aggregate principal amount of the Notes that may be issued under the Indenture, in connection with the Underwriting Agreement, dated as of January 8, 2013, between the Company and certain underwriters named therein, is $500,000,000, and the Stated Maturity of the Notes is January 15, 2043. The Notes shall be offered to the public at a price representing 99.812% of their principal amount.

4. The Notes shall bear interest at the rate of 4.15% per annum. Interest on the Notes will be payable in arrears on January 15 and July 15 of each year (each, an "Interest Payment Date"), beginning July 15, 2013. Interest payable on each Interest Payment Date will include interest accrued from and including January 11, 2013, or from and including the most recent Interest Payment Date to which interest has been paid or duly provided for, as the case may be, to but excluding such Interest Payment Date. Interest will be computed on the basis of a 360-day year of twelve 30-day months. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in the Indenture, be paid to the Holder in whose name the Notes are registered at the close of business on the January 1 or July 1 (whether or not a Business Day) preceding the respective Interest Payment Date. The payment of any Defaulted Interest on the Notes shall be payable to the Holders of the Notes on a Special Record Date established therefor pursuant to the Indenture, or shall be paid at any time in any other lawful manner, all as more fully provided in the Indenture.

5. Payment of the principal of (and premium, if any) and interest on the Notes will be made at the office or agency of the Company maintained for that purpose in the Borough of Manhattan, the City of New York, or at such other office or agency of the Company as may be maintained for such purpose, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. So long as the Notes remain in book-entry form, all payments of principal and interest will be made by the Company in immediately available funds.

6. The Company may redeem the Notes prior to maturity at its option, at any time in whole or from time to time in part. Prior to July 15, 2042, the Redemption Price shall be equal to the greater of:

(a) 100% of the principal amount of the Notes to be redeemed, and

(b) as determined by the Quotation Agent (as defined below), the sum of the present values of the Remaining Scheduled Payments (as defined below) of principal and interest on the Notes to be redeemed discounted to the Redemption Date on a semi-annual basis assuming a 360-day year consisting of twelve 30-day months at the Adjusted Treasury Rate (as defined below) plus 20 basis points;

plus, in each case, accrued and unpaid interest on the principal amount of Notes being redeemed to the Redemption Date.

At any time on or after July 15, 2042, the Redemption Price shall be equal to 100% of the principal amount of the Notes to be redeemed, plus accrued and unpaid interest thereon to the Redemption Date.

"Adjusted Treasury Rate" means, for any Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price of the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that Redemption Date;

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the Notes to be redeemed that would be used, at the time of a selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Notes to be redeemed;

"Comparable Treasury Price" means, for any Redemption Date, the average of the Reference Treasury Dealer Quotations for that Redemption Date;

"Quotation Agent" means the Reference Treasury Dealer appointed by the Company to act as a quotation agent;

"Reference Treasury Dealer" means (i) J.P. Morgan Securities LLC and any Primary Treasury Dealer (as defined below) selected by each of Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc., and any of such parties' successors; provided, however, if any of the foregoing ceases to be a primary U.S. government securities dealer in New York City (a "Primary Treasury Dealer"), the Company will substitute therefor another Primary Treasury Dealer, and (ii) any other Primary Treasury Dealer selected by the Company;

"Reference Treasury Dealer Quotation" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed, in each case, as a percentage of its principal amount) quoted in writing to the Trustee at 5:00 p.m., Eastern time by such Reference Treasury Dealer on the third Business Day preceding such Redemption Date; and

"Remaining Scheduled Payments" means, with respect to each Note to be redeemed, the remaining scheduled payments of the principal and interest on such Note that would be due after the related Redemption Date but for such redemption; provided, however, that if such Redemption Date is not an Interest Payment Date, the amount of the next succeeding scheduled interest payment on such Note will be reduced by the amount of interest accrued on such Note to such Redemption Date.

7. In the case of a partial redemption of the Notes, the Notes to be redeemed shall be selected by the Trustee from the outstanding Notes not previously called for redemption, by such method as the Trustee shall deem fair and appropriate (or, in the case of notes issued in global form, by such method as the depository may require) and which may provide for the selection for redemption of portions of the principal of the Notes. A partial redemption shall not reduce the portion of the principal amount of a Note not redeemed to a principal amount of less than $2,000. Notice of any redemption will be mailed by first class mail at least 30 days but not more than 60 days before the Redemption Date to each Holder of the Notes to be redeemed at its registered address. If any Notes are to be redeemed in part only, the notice of redemption will state the portion of the principal amount of the Notes to be redeemed. A new Note in a principal amount equal to the unredeemed portion of the Note will be issued in the name of the Holder of the Note upon surrender for cancellation of the original Note. Unless the Company defaults in payment of the Redemption Price, on and after the Redemption Date, interest will cease to accrue on the Notes or the portions of the Notes called for redemption.

8. Section 703 of the Indenture is replaced with the following in its entirety for purposes of the Notes only:

The Company shall:

(1) file with the Trustee, within 30 days after the Company has filed the same with the Commission, unless such reports are available on the Commission's EDGAR filing system (or any successor thereto), copies of the annual reports and of the information, documents and other reports (or copies of such portions of any of the foregoing as the Commission may from time to time by rules and regulations prescribe) which the Company may be required to file with the Commission pursuant to Section 13 or Section 15(d) of the Exchange Act; or, if the Company is not required to file information, documents or reports pursuant to either of such Sections, then the Company shall file with the Trustee and the Commission, in accordance with rules and regulations prescribed from time to time by the Commission, such of the supplementary and periodic information, documents and reports which may be required pursuant to Section 13 of the Exchange Act in respect of a security listed and registered on a national securities exchange as may be prescribed from time to time in such rules and regulations;

(2) file with the Trustee and the Commission, in accordance with rules and regulations prescribed from time to time by the Commission, such additional information, documents and reports with respect to compliance by the Company with the conditions and covenants of this Indenture as may be required from time to time by such rules and regulations; and

(3) transmit to all Holders, as their names and addresses appear in the Security Register, within 30 days after the filing thereof with the Trustee, in the manner and to the extent provided in TIA Section 313(c), such summaries of any information, documents and reports required to be filed by the Company pursuant to Subsections (1) and (2) of this Section 703 as may be required by rules and regulations prescribed from time to time by the Commission.

9. The Company has no obligation to redeem, purchase or repay the Notes pursuant to any mandatory redemption or sinking fund or analogous provisions or at the option of the Holder thereof.

10. The entire $500,000,000 principal amount of the Notes shall be payable upon declaration of acceleration of the Maturity thereof pursuant to the Indenture.

11. The defeasance and covenant defeasance provisions of Article Fourteen of the Indenture shall apply to the Notes.

12. The Trustee, the initial Paying Agent and the initial Security Registrar for the Notes shall be U.S. Bank National Association. The Security Register for the Notes shall be initially maintained at, and the place where such Notes may be surrendered for registration of transfer or exchange shall be, the Trustee's Corporate Trust Office located at 1349 West Peachtree Street, Suite 1050, Atlanta, Georgia.

13. The Notes will be issued in registered permanent global form and each evidenced by a global security (a "Global Security") in substantially the form attached hereto as Exhibit II, with such appropriate insertions, omissions, substitutions and other variations as are required or permitted by the Indenture, and may have imprinted or otherwise reproduced thereon such legend or legends or endorsements, not inconsistent with the provisions of the Indenture, as may be required to comply with any law or with any rules or regulations pursuant thereto, or with any rules of any securities exchange or to conform to general usage, all as may be determined by the officers executing each such Global Security, as evidenced by their execution of such Global Security. The beneficial owners of interests in each of the Global Securities may exchange such interests for Notes, as applicable, in certificated form (the "Definitive Notes") only in limited circumstances as provided in the Indenture. In the event that Definitive Notes are issued in exchange for a Global Security, the form of certificate evidencing each Definitive Note shall be in substantially the form of the attached Global Security, with such changes as are necessary to evidence the Notes in definitive form rather than as a Global Security. The Company initially appoints DTC to act as Depository with respect to the Notes.

14. The Notes are issuable in denominations of $2,000 and any integral multiples of $1,000 in excess thereof.

15. The Events of Default set forth in the Indenture shall apply to the Notes.

16. The Company will not pay Additional Amounts on the Notes held by any Holder who is not a United States person in respect of any tax, assessment or governmental charge withheld or deducted.

15. The Company may, at any time, without the consent of the Holders of the Notes, create and issue additional securities having the same ranking, interest rate, maturity and other terms as the Notes. Any such additional securities shall be consolidated and form the same series of the Notes having the same terms as to status, redemption and otherwise as the Notes under the Indenture.

Each of us further certifies that the form and terms of the Notes as established in this certificate have been established pursuant to Section 301 of the Indenture and comply with the Indenture.

[Signature page follows]

IN WITNESS WHEREOF, I have executed this certificate as of the date first written above.

By: /s/ BRET J. ECKERT
Name: Bret J. Eckert
Title: Senior Vice President and Chief Financial Officer

IN WITNESS WHEREOF, I have executed this certificate as of the date first written above.

By: /s/ LOUIS P. GREGORY
Name: Louis P. Gregory
Title: Senior Vice President, General Counsel and Corporate Secretary

Officers' Certificate Pursuant to Section 301 of the Indenture

Exhibit 4.2

THIS SECURITY IS A GLOBAL SECURITY WITHIN THE MEANING OF THE INDENTURE HEREINAFTER REFERRED TO AND IS REGISTERED IN THE NAME OF A DEPOSITORY OR A NOMINEE THEREOF. THIS SECURITY MAY NOT BE EXCHANGED IN WHOLE OR IN PART FOR A SECURITY REGISTERED, AND NO TRANSFER OF THIS SECURITY IN WHOLE OR IN PART MAY BE REGISTERED, IN THE NAME OF ANY PERSON OTHER THAN SUCH DEPOSITORY OR ITS NOMINEE EXCEPT IN THE LIMITED CIRCUMSTANCES DESCRIBED IN THE INDENTURE.

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (55 WATER STREET, NEW YORK, NEW YORK) TO THE ISSUER OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND SUCH CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO., OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY, ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL, SINCE THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

ATMOS ENERGY CORPORATION

4.15% Senior Notes due 2043

No. 1

CUSIP NO. 049560 AL9
ISIN NO. US049560 AL95

Atmos Energy Corporation, a Texas and Virginia corporation (herein called the "Company", which term includes any successor entity under the Indenture, hereinafter defined), for value received, hereby promises to pay to Cede & Co. or registered assigns the principal sum of FIVE HUNDRED MILLION DOLLARS ($500,000,000) on January 15, 2043 (the "Maturity Date"), at the office or agency of the Company referred to below, and to pay interest thereon from January 11, 2013, or from the most recent Interest Payment Date to which interest has been paid or duly provided for, semiannually in arrears on January 15 and July 15 in each year (each, an "Interest Payment Date"), beginning July 15, 2013 at 4.15% per annum until the principal hereof is paid or duly provided for.

Any payment of principal or interest required to be made on a day that is not a Business Day need not be made on such day, but may be made on the next succeeding Business Day with the same force and effect as if made on such day and no interest shall accrue as a result of such delayed payment. Interest payable on each Interest Payment Date will include interest accrued from and including January 11, 2013, or from and including the most recent Interest Payment Date to which interest has been paid or duly provided for, as the case may be, to but excluding such Interest Payment Date. Interest will be computed on the basis of a 360-day year of twelve 30-day months.

The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in the Indenture, be paid to the person (the "Holder") in whose name this Security (or one or more Predecessor Securities) is registered at the close of business on the January 1 or July 1 (whether or not a Business Day) next preceding such Interest Payment Date (a "Regular Record Date"). Any such interest not so punctually paid or duly provided for ("Defaulted Interest") will forthwith cease to be payable to the Holder on such Regular Record Date and either may be paid to the Person in whose name this Security (or one or more Predecessor Securities) is registered at the close of business on a special record date (the "Special Record Date") for the payment of such Defaulted Interest to be fixed by the Trustee (referred to herein), notice whereof shall be given to the Holder of this Security not less than ten days prior to such Special Record Date, or may be paid at any time in any other lawful manner, all as more fully provided in the Indenture.

For purposes of this Security, "Business Day" means any day that, in the city of the principal Corporate Trust Office of the Trustee and in the City of New York, is neither a Saturday, Sunday, or legal holiday nor a day on which banking institutions are authorized or required by law or regulation to close.

Payment of the principal of (and premium, if any) and interest on this Security will be made at the office or agency of the Company maintained for that purpose in the Borough of Manhattan, the City of New York, or at such other office or agency of the Company as may be maintained for such purpose, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. So long as this Security remains in book-entry form, all payments of principal and interest will be made by the Company in immediately available funds.

Unless the certificate of authentication hereon has been duly executed by the Trustee by manual signature, this Security shall not be entitled to any benefit under the Indenture, or be valid or obligatory for any purpose.

This Security is one of a duly authorized issue of securities of the Company, designated as the 4.15% Senior Notes due 2043 (the "Securities"), issued under an Indenture dated as of March 26, 2009, as it may be supplemented from time to time (referred to herein as the "Indenture"), between the Company and U.S. Bank National Association, as trustee (referred to herein as the "Trustee", which term includes any successor trustee under the Indenture with respect to the series of which this Security is a part). A reference is hereby made to the Indenture for a statement of the respective rights, limitations of rights, duties, obligations and immunities thereunder of the Company, the Trustee and the Holders of the Securities, and of the terms upon which the Securities are, and are to be, authenticated and delivered, except as otherwise provided herein.

The Securities are initially limited to $500,000,000 aggregate principal amount. The Company may, at any time, without the consent of the Holders of the Securities, create and issue additional securities having the same ranking, interest rate, maturity and other terms as the Securities. Any such additional securities shall be consolidated and form the same series of the Securities having the same terms as to status, redemption and otherwise as the Securities under the Indenture.

Events of Default . If an Event of Default shall occur and be continuing, the principal of all the Securities may be declared due and payable in the manner and with the effect provided in the Indenture.

Optional Redemption . The Securities will be redeemable prior to maturity at the Company's option, at any time in whole or from time to time in part. Prior to July 15, 2042, the Redemption Price will be equal to the greater of:

(a) 100% of the principal amount of the Securities to be redeemed, and

(b) as determined by the Quotation Agent, the sum of the present values of the Remaining Scheduled Payments of principal and interest on the Securities to be redeemed discounted to the Redemption Date on a semi-annual basis assuming a 360-day year consisting of twelve 30-day months at the Adjusted Treasury Rate plus 20 basis points;

plus, in each case, accrued and unpaid interest on the principal amount of Securities being redeemed to the Redemption Date.

At any time on or after July 15, 2042, the Redemption Price will be equal to 100% of the principal amount of the Securities to be redeemed, plus accrued and unpaid interest thereon to the Redemption Date.

"Adjusted Treasury Rate" means, for any Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price of the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that Redemption Date.

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the Securities to be redeemed that would be used, at the time of a selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Securities to be redeemed.

"Comparable Treasury Price" means, for any Redemption Date, the Reference Treasury Dealer Quotation for that Redemption Date.

"Quotation Agent" means the Reference Treasury Dealer appointed by the Company to act as a quotation agent.

"Reference Treasury Dealer" means (i) J.P. Morgan Securities LLC and any Primary Treasury Dealer (as defined below) selected by each of Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc., and any of such parties' successors; provided, however, if any of the foregoing ceases to be a primary U.S. government securities dealer in New York City (a "Primary Treasury Dealer"), the Company will substitute therefor another Primary Treasury Dealer, and (ii) any other Primary Treasury Dealer selected by the Company.

"Reference Treasury Dealer Quotation" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed, in each case, as a percentage of its principal amount) quoted in writing to the Trustee at 5:00 p.m., Eastern time by such Reference Treasury Dealer on the third Business Day preceding such Redemption Date.

"Remaining Scheduled Payments" means, with respect to each Security to be redeemed, the remaining scheduled payments of the principal and interest on such Security that would be due after the related Redemption Date but for such redemption; provided, however, that if such Redemption Date is not an Interest Payment Date, the amount of the next succeeding scheduled interest payment on such Security will be reduced by the amount of interest accrued on such Security to such Redemption Date.

In the event that less than all of the Securities are to be redeemed at any time, selection of such Securities for redemption will be made by The Depository Trust Company ("DTC") during any period the Securities are issued in the form of a global security registered in the name of DTC or a nominee thereof; *provided that* during any period the Securities are issued in certificated form, the selection of such Securities for redemption will be made by the Trustee by lot or by such other method as the Trustee in its sole discretion shall deem fair and appropriate (or, in the case of Securities issued in global form, by such method as the depositary may require) and which may provide for the selection for redemption of portions of the principal of the Securities. A partial redemption shall not reduce the portion of the principal amount of a Security not redeemed to a principal amount of less than $2,000. Notice of redemption shall be given by first-class mail, postage prepaid, mailed not less than 30 nor more than 60 days before the Redemption Date, to each Holder of Securities to be redeemed, at its address as shown in the Security Register. If the Securities are to be redeemed in part only, the notice of redemption that relates to such Securities shall state the portion of the principal amount thereof to be redeemed. A new Security in a principal amount equal to the unredeemed portion thereof will be issued in the name of the Holder thereof upon surrender for cancellation of the original Security. On and after the Redemption Date, interest will cease to accrue on Securities or portions thereof called for redemption unless the Company defaults in the payment of the Redemption Price.

Sinking Fund. This Security does not have the benefit of any sinking fund obligations.

Modification and Waivers; Obligations of the Company Absolute. The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Securities. Certain limited amendments may be effected under the Indenture at any time by the Company and the Trustee without the consent of any Holders of the Securities. Certain other amendments affecting the Securities may only be effected under the Indenture with the consent of the Holders of not less than a majority in aggregate principal amount of the Securities at the time Outstanding. The Indenture also contains provisions permitting the Holders of not less than a majority in principal amount of the Securities at the time Outstanding, on behalf of the Holders of all Outstanding Securities, to waive compliance by the Company with certain provisions of the Indenture affecting the Securities. Furthermore, provisions in the Indenture permit the Holders of not less than a majority in principal amount of the Outstanding Securities to waive on behalf of all of the Holders of all Outstanding Securities certain past defaults under the Indenture in respect of the Securities and their consequences. Any such consent or waiver by or on behalf of the Holder of this Security shall be conclusive and binding upon such Holder and upon all future Holders of this Security and of any Security issued upon the registration of transfer hereof or in exchange herefor or in lieu hereof whether or not notation of such consent or waiver is made upon this Security.

No reference herein to the Indenture and no provision of this Security or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of (and premium, if any) and interest on this Security at the times, place and rate, and in the coin or currency, herein prescribed.

Defeasance and Covenant Defeasance. The Indenture contains provisions for defeasance at any time of (a) the entire indebtedness of the Company represented by this Security and (b) certain restrictive covenants and the related Defaults and Events of Default, upon compliance by the Company with certain conditions set forth therein, which provisions apply to this Security.

Authorized Denominations. The Securities are issuable only in registered form, without coupons, in minimum denominations of $2,000 and any integral multiple of $1,000 in excess thereof.

Registration of Transfer or Exchange. As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Security is registrable on the Security Register of the Company, upon surrender of this Security for registration of transfer at the office or agency of the Company, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar duly executed by, the Holder hereof or his attorney duly authorized in writing, and thereupon one or more new Securities, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees. At the date of the original issuance of this Security such office or agency of the Company is maintained by U.S. Bank National Association, 1349 West Peachtree Street, Suite 1050, Atlanta, Georgia.

As provided in the Indenture and subject to certain limitations therein set forth, the Securities are exchangeable for a like aggregate principal amount of Securities of a different authorized denomination, as requested by the Holder surrendering the same.

No service charge shall be made for any registration of transfer or exchange or redemption of Securities, but the Company may require payment of a sum sufficient to pay all documentary, stamp or similar issue or transfer taxes or other governmental charges payable in connection with any registration of transfer or exchange.

Prior to the time of due presentment of this Security for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Security is registered as the owner hereof for all purposes, whether or not this Security be overdue, and neither the Company, the Trustee nor any agent shall be affected by notice to the contrary.

Defined Terms . All capitalized terms used in this Security which are defined in the Indenture shall have the meanings assigned to them in the Indenture.

Governing Laws . This Security and the Indenture shall be governed by and construed in accordance with the laws of the State of New York, without regard to conflicts of laws principles that would apply any other law.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed.

ATMOS ENERGY CORPORATION

By: /s/ BRET J. ECKERT
Name: Bret J. Eckert
Title: Senior Vice President and Chief Financial Officer

Attest:

By: /s/ LOUIS P. GREGORY
Name: Louis P. Gregory
Title: Senior Vice President, General Counsel and Corporate Secretary

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This is one of the Securities of the series designated therein referred to in the within-mentioned Indenture.

Dated: January 11, 2013

U.S. Bank National Association,
as Trustee

By: /s/ JACK ELLERIN
Authorized Officer

ASSIGNMENT FORM

To assign this Security, fill in the form below:
(I) or (we) assign and transfer this Security to

____

(Insert assignee's social security or tax I.D. no.)

____

____

____

____

(Print or type assignee's name, address and zip code)

and irrevocably appoint ____________________ agent to transfer this Security on the books of the Company. The agent may substitute another to act for him.

Date: ________ Signature: ____________________________

(sign exactly as name appears on the other side of this Security)

Signature guaranteed by: ____________________

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 8-K

Current Report

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

January 8, 2013
Date of Report (Date of earliest event reported)

ATMOS ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

TEXAS AND VIRGINIA	**1-10042**	**75-1743247**
(State or Other Jurisdiction of Incorporation)	**(Commission File Number)**	**(I.R.S. Employer Identification No.)**

1800 THREE LINCOLN CENTRE, 5430 LBJ FREEWAY, DALLAS, TEXAS	**75240**
(Address of Principal Executive Offices)	**(Zip Code)**

(972) 934-9227
(Registrant's Telephone Number, Including Area Code)

Not Applicable
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

On January 8, 2013, Atmos Energy Corporation ("Atmos Energy") entered into an underwriting agreement (the "Underwriting Agreement") with J.P. Morgan Securities LLC, Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc., as representatives of the several underwriters named in Schedule I thereto, with respect to the offering and sale in an underwritten public offering (the "Offering") by Atmos Energy of $500 million aggregate principal amount of its 4.15% Senior Notes due 2043 (the "Notes"), with a yield to maturity of 4.161% and an effective yield to maturity of 4.636%, after giving effect to the settlement of related Treasury lock agreements. The Offering has been registered under the Securities Act pursuant to a registration statement on Form S-3 (Registration No. 333-165818) of Atmos Energy (the "Registration Statement"), and the prospectus supplement dated January 8, 2013, which was filed with the Securities and Exchange Commission pursuant to Rule 424(b) of the Securities Act on January 9, 2013. Legal opinions related to the Registration Statement are also filed herewith as Exhibits 5.1 and 5.2.

Atmos Energy expects to receive net proceeds, after the underwriting discount and estimated offering expenses, of approximately $494 million. The Offering is expected to close on January 11, 2013, subject to customary closing conditions.

The Notes will be issued pursuant to an indenture dated March 26, 2009 (the "Indenture") between Atmos Energy and U.S. Bank, National Association, as trustee (the "Trustee"), to be modified by an Officers' Certificate setting forth the terms of the Notes (the "Officers' Certificate"), to be dated January 11, 2013 and delivered to the Trustee pursuant to Section 301 of the Indenture. The Notes will be represented by a global security, a form of which is filed as an exhibit hereto. The form of Officers' Certificate and the Underwriting Agreement are each also filed as an exhibit hereto.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*

Exhibit Number	Description
1.1	Underwriting Agreement dated as of January 8, 2013
4.1	Form of Officers' Certificate, to be dated January 11, 2013
4.2	Form of Global Security for 4.15% Senior Notes due 2043
5.1	Opinion of Gibson, Dunn & Crutcher LLP
5.2	Opinion of Hunton & Williams LLP
23.1	Consent of Gibson, Dunn & Crutcher LLP (included in Exhibit 5.1)
23.2	Consent of Hunton & Williams LLP (included in Exhibit 5.2)

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

DATE: January 11, 2013

By: /s/ LOUIS P. GREGORY
Louis P. Gregory
Senior Vice President, General Counsel and Corporate Secretary

INDEX TO EXHIBITS

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Exhibit 1.1

EXECUTION VERSION

ATMOS ENERGY CORPORATION

$500,000,000 4.15% Senior Notes due 2043

UNDERWRITING AGREEMENT

January 8, 2013

J.P. Morgan Securities LLC
Mitsubishi UFJ Securities (USA), Inc.
U.S. Bancorp Investments, Inc.

As Representatives of the several
Underwriters named in Schedule I attached hereto

c/o J.P. Morgan Securities LLC
383 Madison Avenue
New York, NY 10179

Ladies and Gentlemen:

Atmos Energy Corporation, a Texas and Virginia corporation (the " **Company** "), proposes to sell $500,000,000 aggregate principal amount of the Company's 4.15% Senior Notes due 2043 on the terms and conditions stated herein (the " **Securities** "). This is to confirm the agreement concerning the purchase of the Securities from the Company by the Underwriters for whom J.P. Morgan Securities LLC, Mitsubishi UFJ Securities (USA), Inc., and U.S. Bancorp Investments, Inc. are acting as representatives (the " **Representatives** "). The Securities are to be issued pursuant to an indenture, dated as of March 26, 2009 (the " **Indenture** ") between the Company and U.S. Bank National Association, as trustee (the " **Trustee** ") and an officers' certificate to be dated as of January 11, 2013 pursuant to Section 301 of the Indenture (the " **Section 301 Officers' Certificate** "). The Securities and the Indenture are more fully described in the Prospectus (defined below).

1. *Representations, Warranties and Agreements of the Company* . The Company represents, warrants and agrees that:

(a) A registration statement on Form S-3 (File No. 333-165818), including a base prospectus relating to the Securities (i) has been prepared by the Company in conformity with the requirements of the Securities Act of 1933, as amended (the " **Securities Act** "), and the rules and regulations (the " **Rules and Regulations** ") of the Securities and Exchange Commission (the " **Commission** ") thereunder; (ii) has been filed with the Commission under the Securities Act; and (iii) is effective under the Securities Act. Copies of the Registration Statement (as defined below) have been delivered by the Company to you as the Representatives of the Underwriters. As used in this Agreement:

(i) " **Applicable Time** " means 3:00 p.m. (New York City time) on the date of this Agreement;

(ii) " **Effective Date** " means any date as of which any part of the Registration Statement became effective under the Securities Act in accordance with the Rules and Regulations;

(iii) " **General Use Issuer Free Writing Prospectus** " means any Issuer Free Writing Prospectus that is intended for general distribution to prospective investors as evidenced by its being so specified in Schedule II to this Agreement;

(iv) " **Issuer Free Writing Prospectus** " means any "free writing prospectus" (as defined in Rule 405 of the Rules and Regulations) prepared by or on behalf of the Company or used or referred to by the Company in connection with the offering of the Securities;

(v) " **Preliminary Prospectus** " means the base prospectus included in the Registration Statement, together with any preliminary prospectus supplement relating to the Securities filed with the Commission pursuant to Rule 424(b) of the Rules and Regulations;

(vi) " **Pricing Disclosure Package** " means, as of the Applicable Time, the most recent Preliminary Prospectus, together with any General Use Issuer Free Writing Prospectus filed or used by or on behalf of the Company on or before the Applicable Time as permitted by this Agreement;

(vii) " **Prospectus** " means the base prospectus included in the Registration Statement, together with the final prospectus supplement relating to the Securities filed with the Commission pursuant to Rule 424(b) of the Rules and Regulations; and

(viii) " **Registration Statement** " means, the registration statement described above, as amended as of the Effective Date, including the Prospectus and all exhibits to such registration statement and any document incorporated by reference therein.

Any reference to any Preliminary Prospectus or the Prospectus shall be deemed to refer to and include any documents incorporated by reference therein pursuant to Form S-3 under the Securities Act as of the date of such Preliminary Prospectus or the Prospectus, as the case may be. Any reference to the " **most recent Preliminary Prospectus** " shall be deemed to refer to the base prospectus included in the Registration Statement, together with the latest preliminary prospectus supplement relating to the Securities filed with the Commission pursuant to Rule 424(b) prior to or on the date hereof (including, for purposes hereof, any documents incorporated by reference therein prior to or on the date hereof). Any reference to any amendment or supplement to any Preliminary Prospectus or the Prospectus shall be deemed to refer to and include any document filed under the Securities Exchange Act of 1934, as amended (the " **Exchange Act** "), after the date of such Preliminary Prospectus or the Prospectus, as the case may be, and incorporated by reference in such Preliminary Prospectus or the Prospectus, as the case may be; and any reference to any amendment to the Registration Statement shall be deemed to include any annual report of the Company on Form 10-K filed with the Commission pursuant to Section 13(a) or 15(d) of the Exchange Act after the Effective Date that is incorporated by reference in the Registration Statement. The Commission has not issued any stop order preventing or suspending the use of any Preliminary Prospectus or the Prospectus or suspending the effectiveness of the Registration

Statement, and no proceeding or examination for such purpose or pursuant to Section 8A of the Securities Act against the Company or related to the offering of the Securities has been instituted or, to the knowledge of the Company, threatened by the Commission. The Commission has not notified the Company of any objection to the use of the form of the Registration Statement.

(b) At the time of filing the Registration Statement and, if applicable, at the time of the most recent amendment thereto for purposes of complying with Section 10(a)(3) of the Securities Act, the Company was a "well-known seasoned issuer" (as defined in Rule 405 of the Rules and Regulations) eligible to use Form S-3 for the offering of the Securities, including not having been an "ineligible issuer" (as defined in Rule 405 of the Rules and Regulations) at any such time. The Registration Statement is an "automatic shelf registration statement" (as defined in Rule 405 of the Rules and Regulations) and was filed not earlier than the date that is three years prior to the Delivery Date (as defined in Section 4).

(c) The Registration Statement conformed and will conform in all material respects on the Effective Date and on the Delivery Date, and any amendment to the Registration Statement filed after the date hereof will conform in all material respects when filed, to the requirements of the Securities Act and the Rules and Regulations. The Preliminary Prospectus conformed, and the Prospectus will conform, in all material respects when filed with the Commission pursuant to Rule 424(b) and on the Delivery Date to the requirements of the Securities Act and the Rules and Regulations. The documents incorporated by reference in any Preliminary Prospectus or the Prospectus conformed, and any further documents so incorporated will conform, when filed with the Commission, in all material respects to the requirements of the Exchange Act, the Securities Act or the Trust Indenture Act, as applicable, and the rules and regulations of the Commission thereunder.

(d) The Registration Statement did not, as of the Effective Date, contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein not misleading; *provided* that no representation or warranty is made as to information contained in or omitted from the Registration Statement in reliance upon and in conformity with written information furnished to the Company through the Representatives by or on behalf of any Underwriter specifically for inclusion therein, which information is specified in Section 8(e) .

(e) The Prospectus will not, as of its date and on the Delivery Date, contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; *provided* that no representation or warranty is made as to information contained in or omitted from the Prospectus in reliance upon and in conformity with written information furnished to the Company through the Representatives by or on behalf of any Underwriter specifically for inclusion therein, which information is specified in Section 8 (e) .

(f) The documents incorporated by reference in any Preliminary Prospectus or the Prospectus did not, and any further documents filed and incorporated by reference therein will not, when filed with the Commission, contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading. There are no contracts or documents which are required to be described in the Registration Statement, the Prospectus or the documents incorporated by reference therein or to be filed as exhibits thereto which have not been so described and filed as required.

(g) The Pricing Disclosure Package did not, as of the Applicable Time, contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; *provided* that no representation or warranty is made as to information contained in or omitted from the Pricing Disclosure Package in reliance upon and in conformity with written information furnished to the Company through the Representatives by or on behalf of any Underwriter specifically for inclusion therein, which information is specified in Section 8(e) .

(h) Each Issuer Free Writing Prospectus (including, without limitation, any road show that is a free writing prospectus under Rule 433), when considered together with the Pricing Disclosure Package as of the Applicable Time, did not contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading.

(i) Each Issuer Free Writing Prospectus conformed or will conform in all material respects to the requirements of the Securities Act and the Rules and Regulations on the date of first use, and the Company has complied with any filing requirements applicable to such Issuer Free Writing Prospectus pursuant to the Securities Act and the Rules and Regulations. Each Issuer Free Writing Prospectus does not and will not conflict with the information contained in the Registration Statement, the most recent Preliminary Prospectus or the Prospectus. The Company has not made any offer relating to the Securities that would constitute an Issuer Free Writing Prospectus without the prior written consent of the Representatives. The Company has retained in accordance with the Rules and Regulations all Issuer Free Writing Prospectuses that were not required to be filed pursuant to the Rules and Regulations.

(j) The Company has been duly organized and is validly existing as a corporation in good standing under the laws of the State of Texas and the Commonwealth of Virginia and has corporate power and authority to own, lease and operate its properties and to conduct its business as described in the most recent Preliminary Prospectus and to enter into and perform its obligations under this Agreement, the Indenture and the Securities; and the Company is duly qualified as a foreign corporation to transact business and is in good standing in each other jurisdiction in which such qualification is required, whether by reason of the ownership or leasing of property or the conduct of business, except where the failure so to qualify or to be in good standing would not result in a material adverse change, or a development known to the Company involving a prospective material adverse change, in the condition, financial or otherwise, or in the earnings, business affairs or business prospects of the Company and its subsidiaries considered as one enterprise, whether or not arising in the ordinary course of business (a " **Material Adverse Effect** ").

(k) Each "significant subsidiary" (as such term is defined in Rule 405 of the Securities Act) of the Company (each a " **Subsidiary** " and, collectively, the " **Subsidiaries** "), if any, (a) has been duly organized and is validly existing as an entity in good standing under the laws of the jurisdiction of its formation, (b) has corporate or limited liability company power and authority, as applicable, to own, lease and operate its properties and to conduct its business as described in the most recent Preliminary Prospectus and (c) is duly qualified as a foreign entity to transact business and is in good standing in each jurisdiction in which such qualification is required, whether by reason of the ownership or leasing of property or the conduct of business, except in the cases of clauses (b) and (c) where the failure to have such power and authority or to so qualify or to be in good standing would not result in a Material Adverse Effect. The only Subsidiaries of the Company are the subsidiaries listed on Schedule IV and the Company does not own or control, directly or indirectly, any corporation, association or other entity other than the subsidiaries listed on Schedule III .

(l) The authorized, issued and outstanding capital stock of the Company is as set forth in the most recent Preliminary Prospectus and the Prospectus under the caption "Capitalization" (except for subsequent issuances, if any, pursuant to reservations, agreements, acquisitions or employee benefit plans each referred to in the most recent Preliminary Prospectus and the Prospectus or pursuant to the exercise of options or share unit awards, each referred to in the most recent Preliminary Prospectus and the

Prospectus). The shares of issued and outstanding capital stock of the Company have been duly authorized and validly issued and are fully paid and non-assessable; none of the outstanding shares of capital stock of the Company was issued in violation of the preemptive or other similar rights of any securityholder of the Company.

(m) All of the issued and outstanding capital stock or limited liability company membership interests, as the case may be, of each Subsidiary have been duly authorized and validly issued, are fully paid and non-assessable and are owned by the Company, directly or through subsidiaries, free and clear of any security interest, mortgage, pledge, lien, encumbrance, claim or equity except for such liens, encumbrances, equities or claims as would not, in the aggregate, reasonably be expected to have a Material Adverse Effect; none of the outstanding shares of capital stock or limited liability company membership interests, as the case may be, of any Subsidiary was issued in violation of the preemptive or similar rights of any securityholder of such Subsidiary.

(n) The Indenture has been duly qualified under the Trust Indenture Act. The Indenture has been duly authorized, executed and delivered by the Company and constitutes a valid and binding agreement of the Company, enforceable against the Company in accordance with its terms, except as enforceability thereof may be limited by bankruptcy, insolvency, reorganization, moratorium or similar laws relating to or affecting the enforcement of creditors' rights generally and by equitable principles of general applicability, regardless of whether such enforceability is considered in a proceeding at equity or at law. At the Delivery Date, the Section 301 Officers' Certificate will have been duly authorized, executed and delivered by the Company.

(o) The Securities have been duly authorized by the Company and, at the Delivery Date, will have been duly executed by the Company and, when authenticated, issued and delivered in the manner provided for in the Indenture and delivered against payment of the purchase price therefor as provided in this Agreement, will constitute valid and binding obligations of the Company, enforceable against the Company in accordance with their terms, except as enforcement thereof may be limited by bankruptcy, insolvency, reorganization, moratorium or similar laws relating to or affecting the enforcement of creditors' rights generally and by equitable principles of general applicability, regardless of whether such enforceability is considered in a proceeding at equity or at law, and will be in the form contemplated by the Pricing Disclosure Package, the Prospectus, the Indenture and the Section 301 Officers' Certificate, and will be entitled to the benefits of the Indenture.

(p) The Securities and the Indenture will conform in all material respects to the respective statements relating thereto contained in the Pricing Disclosure Package and the Prospectus and will be in substantially the respective forms filed or incorporated by reference, on or prior to the Delivery Date, as exhibits to the Registration Statement.

(q) The Company has all requisite corporate power and authority to execute, deliver and perform its obligations under this Agreement. This Agreement has been duly and validly authorized, executed and delivered by the Company.

(r) Neither the Company nor any of its subsidiaries is in violation of its charter, bylaws or other organizational documents or in default in the performance or observance of any obligation, agreement, covenant or condition contained in any contract, indenture, mortgage, deed of trust, loan or credit agreement, note, lease or other agreement or instrument to which the Company or any of its subsidiaries is a party or by which it or any of them may be bound, or to which any of the property or assets of the Company or any subsidiary is subject (collectively, " **Agreements and Instruments** ") except for such defaults that would not result in a Material Adverse Effect; and the execution, delivery and performance of this Agreement, the Indenture, the Securities and any other agreement or instrument entered into or issued or to be entered into or issued by the Company in connection with the consummation of the transactions contemplated in each of the most recent Preliminary Prospectus and the Prospectus (including the issuance and sale of the Securities and the use of the proceeds from the sale of the Securities as described in each of the most recent Preliminary Prospectus and the Prospectus under the caption "Use of Proceeds") and compliance by the Company with its obligations hereunder and thereunder have been duly authorized by all necessary corporate or other action on the part of the Company and any of the subsidiaries and do not and will not, whether with or without the giving of notice or passage of time or both, conflict with or constitute a breach of, or default or Repayment Event (as defined below) under, or result in the creation or imposition of any lien, charge or encumbrance upon any property or assets of the Company or any subsidiary pursuant to, the Agreements and Instruments (except for such conflicts, breaches or defaults or liens, charges, encumbrances or a Repayment Event that would not result in a Material Adverse Effect), nor will such action result in any violation of (i) the provisions of the charter, bylaws or other organizational documents of the Company or any subsidiary or (ii) any applicable law, statute, rule, regulation, judgment, order, writ or decree of any government, government instrumentality or court, domestic or foreign, having jurisdiction over the Company or any subsidiary or any of their assets, properties or operations except, with respect to (ii), as would not result in a Material Adverse Effect. As used herein, a " **Repayment Event** " means any event or condition which gives the holder of any note, debenture or other evidence of indebtedness (or any person acting on such holder's behalf) the right, whether with or without giving of notice or passage of time or both, to require the repurchase, redemption or repayment of all or a portion of such indebtedness by the Company or any subsidiary.

(s) No labor dispute with the employees of the Company or any of its subsidiaries exists or, to the knowledge of the Company, is imminent, and the Company is not aware of any existing or imminent labor disturbance by the employees of any of its or any subsidiary's principal suppliers, manufacturers, customers or contractors, which, in either case, may reasonably be expected to result in a Material Adverse Effect.

(t) There is no action, suit, proceeding, inquiry or investigation before or brought by any court or governmental agency or body, domestic or foreign, now pending against, or, to the knowledge of the Company, threatened against or affecting the Company or any of its subsidiaries, which is required to be disclosed in the most recent Preliminary Prospectus (other than as disclosed therein), or which might reasonably be expected to result in a Material Adverse Effect, or which might reasonably be expected to affect the properties, assets or operations of the Company and its subsidiaries, except what does not result in a Material Adverse Effect, or the consummation of the transactions contemplated in this Agreement or the performance by the Company and its subsidiaries of its obligations hereunder.

(u) The Company and each of its Subsidiaries own or possess or have the right to use, or can acquire on reasonable terms, adequate patents, patent rights, licenses, inventions, copyrights, know-how (including trade secrets and other unpatented and/or unpatentable proprietary or confidential information, systems or procedures), trademarks, service marks, trade names or other intellectual property (collectively, " **Intellectual Property** ") necessary to carry on the business now operated by them the absence of which would have a Material Adverse Effect, and neither the Company nor any of its subsidiaries has received any notice or is otherwise aware of any infringement of or conflict with asserted rights of others with respect to any Intellectual Property or of any facts or circumstances which would render any Intellectual Property invalid or inadequate to protect the interest of the Company or any of its subsidiaries therein, and which infringement, conflict, invalidity or inadequacy would result in a Material Adverse Effect.

(v) There have been issued and, at the Applicable Time and the Delivery Date, there shall be in full force and effect orders or authorizations of the regulatory authorities of the States of Colorado, Georgia, Kentucky and Virginia, authorizing the issuance and sale of the Securities on terms herein set forth or contemplated, and no other filing with, or authorization, approval, consent, license, order, registration, qualification or decree of, any court or governmental authority or agency is necessary or required for the performance by the Company of its obligations hereunder, in connection with the offering, issuance or sale of the Securities hereunder or the consummation of the transactions contemplated by this Agreement, including the due execution, delivery or performance of the Indenture and the issuance of the Securities by the Company, except such as have been already obtained or as may be required under the Securities Act or the Rules and Regulations or state securities or blue sky laws.

(w) The Company and its subsidiaries possess such permits, licenses, approvals, consents, and other authorizations (collectively, " **Governmental Licenses** ") issued by the appropriate federal, state, local or foreign regulatory agencies or bodies necessary to conduct the business now operated by them, except where the failure to do so would not have a Material Adverse Effect; the Company and its subsidiaries are in compliance with the terms and conditions of all such Governmental Licenses, except where the failure so to comply would not, singly or in the aggregate, have a Material Adverse Effect; all of the Governmental Licenses are valid and in full force and effect, except when the invalidity of such Governmental Licenses or the failure of such Governmental Licenses to be in full force and effect would not have a Material Adverse Effect; and neither the Company nor any of its subsidiaries has received any notice of proceedings relating to the revocation or modification of any such Governmental Licenses which, singly or in the aggregate, would result in a Material Adverse Effect.

(x) There are no persons or entities with registration rights or other similar rights to have any securities registered under the Registration Statement who have not properly waived such rights in connection with the securities registered pursuant to the Registration Statement and in connection with this offering of Securities.

(y) The Company and its subsidiaries have good title to all real property owned by the Company and its subsidiaries and good title to all other properties owned by them, in each case, free and clear of all mortgages, pledges, liens, security interests, claims, restrictions or encumbrances of any kind except such as (a) are described in the most recent Preliminary Prospectus or (b) would not singly or in the aggregate have a Material Adverse Effect. All of the leases and subleases of the Company and its subsidiaries under which the Company or any of its subsidiaries holds properties described in the most recent Preliminary Prospectus are in full force and effect, except as would not result in a Material Adverse Effect.

(z) The Company has not sold or issued any securities that would be integrated with the offering of the Securities contemplated by this Agreement pursuant to the Securities Act, the Rules and Regulations or the interpretations thereof by the Commission.

(aa) The financial statements of the Company included or incorporated by reference in the Registration Statement, the most recent Preliminary Prospectus and the Prospectus, together with the related schedules and notes, present fairly in all material respects the financial position of the Company and its consolidated subsidiaries at the dates indicated and the statement of operations, stockholders' equity and cash flows of the Company and its consolidated subsidiaries for the periods specified; said financial statements have been prepared in conformity with generally accepted accounting principles (" **GAAP** ") applied on a consistent basis throughout the periods involved. The supporting schedules, if any, included in the Registration Statement and incorporated by reference in the most recent Preliminary Prospectus and the Prospectus with respect to the Company, when considered in relation to the financial statements taken as a whole, present fairly, in all material respects in accordance with GAAP, the financial information set forth therein. The selected financial data and the summary financial information included or incorporated by reference in the most recent Preliminary Prospectus and the Prospectus present fairly, in all material respects, the information shown therein and have been compiled on a basis consistent with that of the audited financial statements of the Company.

(bb) Ernst & Young LLP, who have audited financial statements and supporting schedules of the Company and its consolidated subsidiaries incorporated by reference in the most recent Preliminary Prospectus and in the Registration Statement, whose report is incorporated by reference in the most recent Preliminary Prospectus and in the Registration Statement, who have audited the Company's internal control over financial reporting and who have delivered the initial letter referred to in Section 7(g) hereof, are independent registered public accountants as required by the Securities Act and the Rules and Regulations.

(cc) The interactive data in the eXtensible Business Reporting Language incorporated by reference in the Registration Statement fairly presents the information called for in all material respects and has been prepared in accordance with the Commission's rules and guidelines applicable thereto.

(dd) The Company and each of its subsidiaries are not, and as of the Delivery Date and upon the issuance and sale of the Securities and the application of the proceeds therefrom as described under "Use of Proceeds" in the most recent Preliminary Prospectus and the Prospectus, none of them will be, (i) an "investment company" or an entity "controlled" by an "investment company" as such terms are defined in the Investment Company Act of 1940, as amended (the " **Investment Company Act** ") and the rules and regulations of the Commission thereunder or (ii) a "business development company" (as defined in Section 2(a)(48) of the Investment Company Act).

(ee) (i) Each "employee benefit plan" (within the meaning of Section 3(3) of the Employee Retirement Security Act of 1974, as amended (" **ERISA** ")) for which the Company or any member of its "Controlled Group" (defined as any organization which is a member of a controlled group of corporations within the meaning of Section 414(b) or (c) of the Internal Revenue Code of 1986, as amended (the " **Code** ")) would have any liability (each a " **Plan** ") has been maintained in compliance in all respects with its terms and with the requirements of all applicable statutes, rules and regulations including ERISA and the Code except where failure to do so would not have a Material Adverse Effect; (ii) with respect to each Plan subject to Title IV of ERISA (a) no "reportable event" (within the meaning of Section 4043(c) of ERISA) has occurred or is reasonably expected to occur that would result in a Material Adverse Effect, (b) no "accumulated funding deficiency" (within the meaning of Section 302 of ERISA or Section 412 of the Code), whether or not waived, has occurred or is reasonably expected to occur that would result in a Material Adverse Effect, (c) the fair market value of the assets under each Plan exceeds the actuarial present value of the benefits accrued under such Plan (determined based on those assumptions used to fund such Plan) except where failure to do so would not have a Material Adverse Effect, and (d) neither the Company nor any member of its Controlled Group has incurred, or reasonably expects to incur, any liability under Title IV of ERISA (other than contributions to the Plan or premiums to the Pension Benefit Guaranty Corporation in the ordinary course and without default) in respect of a Plan (including a "multiemployer plan", within the meaning of Section 4001(c)(3) of ERISA) that would result in a Material Adverse Effect; and (iii) each Plan that is intended to be qualified under Section 401(a) of the Code has received a favorable determination letter from the Internal Revenue Service as to its qualified status and nothing has occurred, whether by action or by failure to act, which would cause the loss of such qualification that would result in a Material Adverse Effect.

(ff) The Company is in compliance, in all material respects, with the provisions of the Sarbanes-Oxley Act of 2002 to the extent currently applicable.

(gg) The Company and each of its subsidiaries have filed all federal, state and local income and franchise tax returns required to be filed through the date hereof and have paid all taxes due thereon, except such as are being contested in good faith by appropriate proceedings or where the failure to do so would not have a Material Adverse Effect, and no tax deficiency has been determined adversely to the Company or any of its subsidiaries which has had, and the Company does not have any knowledge of any tax deficiency which would have, a Material Adverse Effect.

(hh) The Company and its subsidiaries carry, or are covered by, insurance in such amounts and covering such risks as is adequate for the conduct of their respective businesses and the value of their respective properties, except where the failure to do so would not reasonably be expected to have a Material Adverse Effect.

(ii) Except as would not result in a Material Adverse Effect, (A) neither the Company nor any of its subsidiaries is in violation of any federal, state, local or foreign statute, law, rule, regulation, ordinance, code, permit, policy or rule of common law or any judicial or administrative interpretation thereof, including any judicial or administrative order, consent, decree or judgment, relating to pollution or protection of human health, the environment (including, without limitation, ambient air, surface water, groundwater, land surface or subsurface strata) or wildlife, including, without limitation, laws and regulations relating to the release or threatened release of chemicals, pollutants, contaminants, wastes, toxic substances, hazardous substances, petroleum or petroleum products (collectively, " **Hazardous Materials** ") or to the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of Hazardous Materials (collectively, " **Environmental Laws** "), (B) the Company and its subsidiaries have all permits, authorizations and approvals required under any applicable Environmental Laws and are each in compliance with their requirements, (C) there are no pending or, to the knowledge of the Company, threatened administrative, regulatory or judicial actions, suits, demands, demand letters, claims, liens, notices of noncompliance or violation, investigation or proceedings relating to any Environmental Law against the Company or any of its subsidiaries and (D) there are no events or circumstances that might reasonably be expected to form the basis of an order for clean-up or remediation, or an action, suit or proceeding by any private party or governmental body or agency, against or affecting the Company or any of its subsidiaries relating to Hazardous Materials or any Environmental Laws, except as disclosed in the Preliminary Prospectus.

(jj) The Company maintains a system of internal control over financial reporting (as such term is defined in Rule 13a-15(f) of the Exchange Act) that complies with the requirements of the Exchange Act and has been designed by the Company's principal executive officer and principal financial officer, or under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. The Company's internal control over financial reporting is effective and the Company is not aware of any material weaknesses in its internal control over financial reporting. Since the date of the latest audited financial statements included or incorporated by reference in the most recent Preliminary Prospectus, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. The Company maintains disclosure controls and procedures (as such term is defined in Rule 13a-15(e) of the Exchange Act) that comply with the requirements of the Exchange Act and such disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to the Company and its subsidiaries that is required to be disclosed in the reports the Company files, furnishes, submits or otherwise provides to the Commission under the Exchange Act is made known to the Company's principal executive officer and principal financial officer by others within those entities in such a manner as to allow timely decisions regarding the required disclosure; such disclosure controls and procedures are effective.

(kk) The Company has not distributed and, prior to the later to occur of the Delivery Date and completion of the distribution of the Securities, will not distribute any offering material in connection with the offering and sale of the Securities other than any Preliminary Prospectus, the Prospectus or any Issuer Free Writing Prospectus to which the Representatives has consented in accordance with Section 1(i) or 5(a)(viii) .

Any certificate signed by any officer of the Company and delivered to the Representatives or counsel for the Underwriters in connection with the offering of the Securities shall be deemed a representation and warranty by the Company, as to matters covered thereby on the date of such certificate, to each Underwriter.

2. *Purchase of the Securities by the Underwriters* . On the basis of the representations and warranties contained in, and subject to the terms and conditions of, this Agreement, the Company agrees to sell $500,000,000 aggregate principal amount of Securities to the several Underwriters, and each of the Underwriters, severally and not jointly, agrees to purchase from the Company, at a purchase price of 98.937% of the principal amount thereof, the aggregate principal amount of Securities set forth opposite that Underwriter's name in Schedule I hereto, plus any additional principal amount of Securities that such Underwriter may become obligated to purchase pursuant to Section 9 of this Agreement.

The Company shall not be obligated to deliver any of the Securities to be delivered on the Delivery Date, except upon payment for all such Securities to be purchased on such Delivery Date as provided herein.

3. *Offering of Securities by the Underwriters* . Upon authorization by the Representatives of the release of the Securities, the several Underwriters propose to offer the Securities for sale upon the terms and conditions to be set forth in the Prospectus.

4. *Delivery of and Payment for the Securities* . Delivery of the Securities by the Company and payment for the Securities by the several Underwriters shall be made at 10:00 A.M., New York City time, on the third full business day following the date of this Agreement or at such other date or place as shall be determined by agreement between the Representatives and the Company. This date and time is referred to as the " **Delivery Date** ." Delivery of the Securities shall be made to the Representatives for the account of each Underwriter against payment by the several Underwriters through the Representatives of the respective aggregate purchase prices, as set forth in Section 2 hereof, of the Securities being sold by the Company to or upon the order of the Company by wire transfer in immediately available funds to the accounts specified by the Company. Time shall be of the essence, and delivery at the time and place specified pursuant to this Agreement is a further condition of the obligation of each Underwriter hereunder. The Company shall deliver the Securities through the facilities of the Depository Trust Company (" **DTC** ") unless the Representatives shall otherwise instruct.

The Securities to be purchased by the Underwriters shall be in such denominations ($2,000 or integral multiples of $1,000 in excess thereof) and registered in such names as the Representatives may request in writing prior to the Delivery Date. The Securities will be made available in New York City for examination by the Underwriters not later than 10:00 A.M., New York City time, on the last business day prior to the Delivery Date.

5. *Further Agreements of the Company and the Underwriters* .

(a) The Company agrees:

(i) To prepare the Prospectus in a form reasonably approved by the Representatives and to file such Prospectus pursuant to Rule 424(b) under the Securities Act not later than the

Commission's close of business on the second business day following the execution and delivery of this Agreement; to make no further amendment or any supplement to the Registration Statement or the Prospectus prior to the Delivery Date except as provided herein; to advise the Representatives, promptly after it receives notice thereof, of the time when any amendment or supplement to the Registration Statement or the Prospectus has been filed and to furnish the Representatives with copies thereof; to file promptly all reports and any definitive proxy or information statements required to be filed by the Company with the Commission pursuant to Section 13(a), 13(c), 14 or 15(d) of the Exchange Act subsequent to the date of the Prospectus and for so long as the delivery of a prospectus is required in connection with the offering or sale of the Securities; to advise the Representatives, promptly after it receives notice thereof, of the issuance by the Commission of any stop order or of any order preventing or suspending the use of the Prospectus or any Issuer Free Writing Prospectus, of the suspension of the qualification of the Securities for offering or sale in any jurisdiction, of the initiation or threatening of any proceeding or examination for any such purpose or pursuant to Section 8A of the Securities Act against the Company or related to the offering of the Securities, of any notice from the Commission objecting to the use of the form of the Registration Statement or any post-effective amendment thereto or of any request by the Commission for the amending or supplementing of the Registration Statement, the Prospectus or any Issuer Free Writing Prospectus or for additional information; and, in the event of the issuance of any stop order or of any order preventing or suspending the use of the Prospectus or any Issuer Free Writing Prospectus or suspending any such qualification, to use promptly its best efforts to obtain its withdrawal;

(ii) To prepare a final term sheet (the " **Final Term Sheet** ") reflecting the final terms of the Securities as set forth in Exhibit A to this Agreement, in form and substance satisfactory to the Representatives, and shall file such Final Term Sheet as an Issuer Free Writing Prospectus pursuant to Rule 433 prior to the close of business two business days after the date hereof; *provided that* the Company shall furnish the Representatives with copies of any such Final Term Sheet a reasonable amount of time prior to such proposed filing and will not use or file any such document to which the Representatives or counsel to the Underwriters shall reasonably object.

(iii) To pay the applicable Commission filing fees relating to the Securities within the time required by Rule 456(b)(1);

(iv) To furnish promptly upon request to counsel for the Underwriters a signed copy of the Registration Statement as originally filed with the Commission, and each amendment thereto filed with the Commission, including all consents and exhibits filed therewith;

(v) To deliver promptly to the Representatives such number of the following documents as the Representatives shall reasonably request: (A) conformed copies of the Registration Statement as originally filed with the Commission and each amendment thereto (in each case excluding exhibits other than this Agreement and the computation of per share earnings), (B) each Preliminary Prospectus, the Prospectus and any amendment or supplement thereto, (C) any Issuer Free Writing Prospectus and (D) any document incorporated by reference in any Preliminary Prospectus or the Prospectus; and, if the delivery of a prospectus is required at any time after the date hereof in connection with the offering or sale of the Securities or any other securities relating thereto and if at such time any events shall have occurred as a result of which the Prospectus as then amended or supplemented would include an untrue statement of a material fact or omit to state any material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made when such Prospectus is delivered, not misleading, or, if for any other reason it shall be necessary to amend or supplement the Prospectus or to file under the Exchange Act any document incorporated by reference in the

Prospectus in order to comply with the Securities Act or the Exchange Act, to notify the Representatives and, upon the Representatives' request, to file such document and to prepare and furnish without charge to each Underwriter and to any dealer in securities as many copies as the Representatives may from time to time reasonably request of an amended or supplemented Prospectus that will correct such statement or omission or effect such compliance;

(vi) To file promptly with the Commission any amendment or supplement to the Registration Statement or the Prospectus that may, in the judgment of the Company or the Representatives, be required by the Securities Act or requested by the Commission;

(vii) Prior to filing with the Commission any amendment or supplement to the Registration Statement or the Prospectus, any document incorporated by reference in the Prospectus or any amendment to any document incorporated by reference in the Prospectus, to furnish a copy thereof to the Representatives and counsel for the Underwriters and obtain the consent (not to be unreasonably withheld) of the Representatives to the filing;

(viii) Not to make any offer relating to the Securities that would constitute an Issuer Free Writing Prospectus without the prior written consent of the Representatives.

(ix) To retain in accordance with the Rules and Regulations all Issuer Free Writing Prospectuses not required to be filed pursuant to the Rules and Regulations and to comply with any filing requirements applicable to all Issuer Free Writing Prospectuses pursuant to the Securities Act and the Rules and Regulations; and if at any time after the date hereof any events shall have occurred as a result of which any Issuer Free Writing Prospectus, as then amended or supplemented, would conflict with the information in the Registration Statement, the most recent Preliminary Prospectus or the Prospectus or would include an untrue statement of a material fact or omit to state any material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading, or, if for any other reason it shall be necessary to amend or supplement any Issuer Free Writing Prospectus, to notify the Representatives and, upon the Representatives' request, to file such document and to prepare and furnish without charge to each Underwriter as many copies as the Representatives may from time to time reasonably request of an amended or supplemented Issuer Free Writing Prospectus that will correct such conflict, statement or omission or effect such compliance;

(x) As soon as practicable, to make generally available to the Company's security holders an earnings statement of the Company and its subsidiaries (which need not be audited) complying with Section 11(a) of the Securities Act and the Rules and Regulations;

(xi) Promptly from time to time to take such action to qualify the Securities for offering and sale under the securities laws of such jurisdictions as the Representatives may reasonably request and to comply with such laws so as to permit the continuance of sales and dealings therein in such jurisdictions for as long as may be necessary to complete the distribution of the Securities; *provided* that in connection therewith the Company shall not be required to (i) qualify as a foreign corporation in any jurisdiction in which it would not otherwise be required to so qualify, (ii) take any action that would subject it to service of process in any such jurisdiction or (iii) subject itself to taxation in any jurisdiction in which it would not otherwise be subject;

(xii) During the period from the date hereof to the Delivery Date, without the prior written consent of the Representatives, the Company agrees not to directly or indirectly, issue, sell, offer or contract to sell, grant any option for the sale of, or otherwise transfer or dispose of, any debt securities issued or guaranteed by the Company other than commercial paper backstopped by the Company's existing credit agreement;

(xiii) To apply the net proceeds from the sale of the Securities being sold by the Company as set forth in the Pricing Disclosure Package.

(xiv) To take all reasonable action necessary to enable Standard & Poor's Rating Services, a division of McGraw Hill, Inc. (" **S&P** "), Moody's Investors Service Inc. (" **Moody's** ") and Fitch IBCA, Inc. (" **Fitch** ") to provide their respective credit ratings of the Securities.

(xv) To cooperate with the Underwriters and use its best efforts to permit the Securities to be eligible for clearance and settlement through the facilities of DTC.

(b) Each Underwriter severally agrees that such Underwriter shall not include any "issuer information" (as defined in Rule 433) in any "free writing prospectus" (as defined in Rule 405) (other than a free writing prospectus that is not required to be filed by the Company pursuant to Rule 433 under the Securities Act) used or referred to by such Underwriter without the prior consent of the Company (any such issuer information with respect to whose use the Company has given its consent, " **Permitted Issuer Information** "); *provided* that (i) no such consent shall be required with respect to any such issuer information contained in any document filed by the Company with the Commission prior to the use of such free writing prospectus and (ii) "issuer information," as used in this Section 5(b), shall not be deemed to include information prepared by or on behalf of such Underwriter on the basis of or derived from issuer information; *provided* , further, that prior to the filing with the Commission of the Final Term Sheet in accordance with Section 5(a)(ii) , the Underwriters are authorized to use the information with respect to the final terms of the Securities in communications conveying information relating to the offering to investors.

6. *Expenses* . The Company agrees, whether or not the transactions contemplated by this Agreement are consummated or this Agreement is terminated, to pay all costs, expenses, fees and taxes incident to and in connection with (a) the preparation, authorization, issuance, sale and delivery of the Securities and any stamp duties or other taxes payable in that connection; (b) the preparation, printing and filing under the Securities Act of the Registration Statement (including any exhibits thereto), any Preliminary Prospectus, the Prospectus, any Issuer Free Writing Prospectus and any amendment or supplement thereto; (c) the distribution of the Registration Statement (including any exhibits thereto), any Preliminary Prospectus, the Prospectus, any Issuer Free Writing Prospectus and any amendment or supplement thereto, or any document incorporated by reference therein, all as provided in this Agreement; (d) the production and distribution of this Agreement, the Indenture, the Securities, any supplemental agreement among Underwriters, and any other related documents in connection with the offering, purchase, sale and delivery of the Securities; (e) the filing fees incident to, and the reasonable fees and disbursements of counsel to the Underwriters in connection with, the review, if any, by the Financial Industry Regulatory Authority, Inc. of the terms of the sale of the Securities; (f) the qualification of the Securities under the securities laws of the several jurisdictions as provided in Section 5(a)(xi) and the preparation, printing and distribution of a Blue Sky Memorandum (including related reasonable fees and expenses of counsel to the Underwriters); (g) the investor presentations on any "road show" undertaken in connection with the marketing of the Securities, including, without limitation, expenses associated with any electronic roadshow, travel and lodging expenses of the representatives and officers of the Company and the cost of any aircraft chartered; (h) any fees payable in connection with the rating of the Securities; (i) the reasonable fees and expenses of the Trustee, including the fees and disbursements of counsel for the Trustee, in connection with the Indenture and the Securities and (j) all other costs and expenses incident to the performance of the obligations of the Company; *provided* that, except as provided in this

Section 6 and Sections 8 and 11, the Underwriters shall pay their own costs and expenses, including the costs and expenses of their counsel, any transfer taxes on the Securities which they may sell and the expenses of advertising any offering of the Securities made by the Underwriters.

7. *Conditions of Underwriters' Obligations* . The respective obligations of the Underwriters hereunder are subject to the accuracy, when made and on the Delivery Date, of the representations and warranties of the Company contained herein, to the performance by the Company of its obligations hereunder, and to each of the following additional terms and conditions:

(a) The Prospectus shall have been timely filed with the Commission in accordance with Section 5(a)(i) ; the Company shall have complied with all filing requirements applicable to any Issuer Free Writing Prospectus, including the Final Term Sheet and any Issuer Free Writing Prospectus used or referred to after the date hereof; no stop order suspending the effectiveness of the Registration Statement or preventing or suspending the use of the Prospectus or any Issuer Free Writing Prospectus shall have been issued and no proceeding or examination for such purpose or pursuant to Section 8A of the Securities Act against the Company or related to the offering of the Securities shall have been initiated or, to the knowledge of the Company, threatened by the Commission; any request of the Commission for inclusion of additional information in the Registration Statement or the Prospectus or otherwise shall have been complied with; and the Commission shall not have notified the Company of any objection to the use of the form of the Registration Statement.

(b) Gibson, Dunn & Crutcher LLP, as counsel to the Company, shall have furnished to the Representatives its written opinion and letter, addressed to the Underwriters and dated such Delivery Date, in form and substance reasonably satisfactory to the Representatives.

(c) Hunton & Williams LLP, as Virginia counsel to the Company, shall have furnished to the Representatives its written opinion, addressed to the Underwriters and dated such Delivery Date, in form and substance reasonably satisfactory to the Representatives, substantially to the effect set forth in Exhibit B-1

(d) Louis P. Gregory, as General Counsel to the Company, shall have furnished to the Representatives his written opinion and letter, addressed to the Underwriters and dated such Delivery Date, in form and substance reasonably satisfactory to the Representatives, substantially to the effect set forth in Exhibit B-2 .

(e) The Trustee shall have received opinion letters, dated such Delivery Date, from Gibson, Dunn & Crutcher LLP and Hunton & Williams LLP, as the Trustee may reasonably require.

(f) The Representatives shall have received from Shearman & Sterling LLP, counsel for the Underwriters, such opinion or opinions, dated such Delivery Date, as the Underwriters may reasonably require.

(g) At the time of execution of this Agreement, the Representatives shall have received from Ernst & Young LLP a letter, in form and substance satisfactory to the Representatives, addressed to the Underwriters and dated the date hereof (i) confirming that they are independent public accountants within the meaning of the Securities Act and are in compliance with the applicable requirements relating to the qualification of accountants under Rule 2-01 of Regulation S-X of the Commission, and (ii) stating, as of the date hereof (or, with respect to matters involving changes or developments since the respective dates as of which specified financial information is given in the most recent Preliminary Prospectus, as of a date not more than three days prior to the date hereof), the conclusions and findings of such firm with respect to the financial information and other matters ordinarily covered by accountants' "comfort letters" to underwriters in connection with registered public offerings.

(h) With respect to the letter of Ernst & Young LLP referred to in the preceding paragraph and delivered to the Representatives concurrently with the execution of this Agreement (the " **initial letter** "), the Company shall have furnished to the Representatives a letter (the " **bring-down letter** ") of such accountants, addressed to the Underwriters and dated such Delivery Date (i) confirming that they are independent public accountants within the meaning of the Securities Act and are in compliance with the applicable requirements relating to the qualification of accountants under Rule 2-01 of Regulation S-X of the Commission, (ii) stating, as of the date of the bring-down letter (or, with respect to matters involving changes or developments since the respective dates as of which specified financial information is given in the Prospectus, as of a date not more than three days prior to the date of the bring-down letter), the conclusions and findings of such firm with respect to the financial information and other matters covered by the initial letter and (iii) confirming in all material respects the conclusions and findings set forth in the initial letter.

(i) The Company shall have furnished to the Representatives a certificate, dated such Delivery Date, of its Chief Executive Officer or its Chief Financial Officer stating that:

(i) The representations, warranties and agreements of the Company in Section 1 are true and correct on and as of such Delivery Date, and the Company has complied with all its agreements contained herein and satisfied all the conditions on its part to be performed or satisfied hereunder at or prior to such Delivery Date;

(ii) No stop order suspending the effectiveness of the Registration Statement has been issued; no proceedings or examination for that purpose or pursuant to Section 8A of the Securities Act against the Company or related to the offering of the Securities have been instituted or, to the knowledge of such officers, threatened; and the Commission has not notified the Company of any objection to the use of the form of the Registration Statement or any post-effective amendment thereto; and

(iii) There has been no material adverse change, or a development known to the Company involving a prospective material adverse change, in the condition, financial or otherwise, or in the earnings, business affairs or business prospects of the Company and its subsidiaries considered as one enterprise, whether or not arising in the ordinary course of business.

(j) There has not been any change, or any development known to the Company involving a prospective change, in the condition, financial or otherwise, or in the earnings, business affairs or business prospects of the Company and its subsidiaries considered as one enterprise, whether or not arising in the ordinary course of business, the effect of which is, in the judgment of the Representatives, so material and adverse as to make it impracticable or inadvisable to proceed with the public offering or the delivery of the Securities being delivered on such Delivery Date on the terms and in the manner contemplated in the Prospectus; and subsequent to the execution and delivery of this Agreement (i) no downgrading shall have occurred in the rating or indicative rating accorded the Company's debt securities by any "nationally recognized statistical rating organization" (as such term as defined in Section 3(a)(62) of the Exchange Act;) and (ii) no such organization shall have publicly announced that it has placed the Company under surveillance or review, with possible negative implications, for its rating or indicative rating of any of the Company's debt securities.

(k) Subsequent to the execution and delivery of this Agreement there shall not have occurred any of the following: (i) trading in securities generally on the New York Stock Exchange or in the over-the-counter market, or trading in any securities of the Company on any exchange or in the over-the-counter market, shall have been suspended or materially limited or the settlement of such trading generally shall have been materially disrupted or minimum prices shall have been established on any such exchange or such market by the Commission, by such exchange or by any other regulatory body or governmental authority having jurisdiction, (ii) a banking moratorium shall have been declared by federal or New York, Texas or Virginia authorities or there shall have occurred any material disruption in commercial banking, securities settlement or clearance services in the United States, (iii) the United States shall have become engaged in hostilities, there shall have been an escalation in hostilities involving the United States or there shall have been a declaration of a national emergency or war by the United States or (iv) there shall have occurred such a material adverse change in general economic, political or financial conditions, including, without limitation, as a result of terrorist activities after the date hereof (or the effect of international conditions on the financial markets in the United States shall be such), in the case of each of the foregoing subsections (i) through (iv) , as to make it, in the judgment of the Representatives, impracticable or inadvisable to proceed with the public offering, sale or delivery of the Securities being delivered on such Delivery Date on the terms and in the manner contemplated in the Pricing Disclosure Package and the Prospectus.

Counsel for the Underwriters shall have been furnished with such documents and opinions as they may reasonably require for the purpose of enabling them to pass upon the issuance and sale of the Securities as herein contemplated, or in order to evidence the accuracy of any of the representations or warranties, or the fulfillment of any of the conditions, herein contained; and all proceedings taken by the Company in connection with the issuance and sale of the Securities as herein contemplated shall be reasonably satisfactory in form and substance to the Representatives and counsel for the Underwriters.

All opinions, letters, evidence and certificates mentioned above or elsewhere in this Agreement shall be deemed to be in compliance with the provisions hereof only if they are in form and substance reasonably satisfactory to counsel for the Underwriters.

8. *Indemnification and Contribution* . (a) The Company shall indemnify and hold harmless each Underwriter, its directors, officers, agents, affiliates and employees and each person, if any, who controls any Underwriter within the meaning of Section 15 of the Securities Act or Section 20 of the Exchange Act, from and against any loss, claim, damage or liability, joint or several, or any action in respect thereof (including, but not limited to, any loss, claim, damage, liability or action relating to purchases and sales of Securities), to which that Underwriter, director, officer, agent, affiliate, employee or controlling person may become subject, under the Securities Act or otherwise, insofar as such loss, claim, damage, liability or action arises out of, or is based upon, (i) any untrue statement or alleged untrue statement of a material fact contained in (A) any Preliminary Prospectus, the Registration Statement, the Prospectus or in any amendment or supplement thereto, (B) any Issuer Free Writing Prospectus or in any amendment or supplement thereto or (C) any Permitted Issuer Information used or referred to in any "free writing prospectus" (as defined in Rule 405) used or referred to by any Underwriter or (ii) the omission or alleged omission to state in any Preliminary Prospectus, the Registration Statement, the Prospectus, any Issuer Free Writing Prospectus or in any amendment or supplement thereto or in any Permitted Issuer Information or any Non-Prospectus Road Show, any material fact required to be stated therein or necessary to make the statements therein not misleading, and shall reimburse each Underwriter and each such director, officer, employee, agent, affiliate or controlling person promptly upon demand for any legal or other expenses reasonably incurred by that Underwriter, director, officer, employee, agent, affiliate or controlling person in connection with investigating or defending or preparing to defend against any such loss, claim, damage, liability or action as such expenses are incurred; *provided* , *however* , that the

Company shall not be liable in any such case to the extent that any such loss, claim, damage, liability or action arises out of, or is based upon, any untrue statement or alleged untrue statement or omission or alleged omission made in any Preliminary Prospectus, the Registration Statement, the Prospectus, any Issuer Free Writing Prospectus or in any such amendment or supplement thereto, in reliance upon and in conformity with written information concerning such Underwriter furnished to the Company through the Representatives by or on behalf of any Underwriter specifically for inclusion therein, which information consists solely of the information specified in Section 8(e). The foregoing indemnity agreement is in addition to any liability which the Company may otherwise have to any Underwriter or to any director, officer, employee, agent, affiliate or controlling person of that Underwriter.

(b) Each Underwriter, severally and not jointly, shall indemnify and hold harmless the Company, its directors, officers agents, affiliates and employees, and each person, if any, who controls the Company within the meaning of Section 15 of the Securities Act or Section 20 of the Exchange Act, from and against any loss, claim, damage, liability or expense (including reasonable attorney's fees and expenses relating to investigating or defending or preparing to defend), joint or several, or any action in respect thereof, to which the Company, or any such director, officer, employee, agent, affiliate or controlling person may become subject, under the Securities Act or otherwise, insofar as such loss, claim, damage, liability or action arises out of, or is based upon, (i) any untrue statement or alleged untrue statement of a material fact contained in any Preliminary Prospectus, the Registration Statement, the Prospectus, any Issuer Free Writing Prospectus or in any amendment or supplement thereto, or (ii) the omission or alleged omission to state in any Preliminary Prospectus, the Registration Statement, the Prospectus, any Issuer Free Writing Prospectus or in any amendment or supplement thereto, any material fact required to be stated therein or necessary to make the statements therein not misleading, but in each case only to the extent that the untrue statement or alleged untrue statement or omission or alleged omission was made in reliance upon and in conformity with written information concerning such Underwriter furnished to the Company through the Representatives by or on behalf of that Underwriter specifically for inclusion therein, which information is limited to the information set forth in Section 8(e). The foregoing indemnity agreement is in addition to any liability that any Underwriter may otherwise have to the Company, or any such director, officer, employee, agent, affiliate or controlling person.

(c) Promptly after receipt by an indemnified party under this Section 8 of notice of any claim or the commencement of any action, the indemnified party shall, if a claim in respect thereof is to be made against the indemnifying party under this Section 8, notify the indemnifying party in writing of the claim or the commencement of that action; *provided*, *however*, that the failure to notify the indemnifying party shall not relieve it from any liability which it may have under this Section 8 except to the extent it has been materially prejudiced by such failure and, *provided*, *further*, that the failure to notify the indemnifying party shall not relieve it from any liability which it may have to an indemnified party otherwise than under this Section 8. If any such claim or action shall be brought against an indemnified party, and it shall notify the indemnifying party thereof, the indemnifying party shall be entitled to participate therein and, to the extent that it wishes, jointly with any other similarly notified indemnifying party, to assume the defense thereof with counsel reasonably satisfactory to the indemnified party. After notice from the indemnifying party to the indemnified party of its election to assume the defense of such claim or action, the indemnifying party shall not be liable to the indemnified party under this Section 8 for any legal or other expenses subsequently incurred by the indemnified party in connection with the defense thereof other than reasonable costs of investigation; *provided, however*, that the indemnified party shall have the right to employ such other counsel as the indemnified party may deem necessary, and the indemnifying party shall bear the reasonable legal or other expenses of such other counsel if (i) the indemnifying party shall have agreed; (ii) the indemnifying party has failed within a reasonable time to assume the defense of and retain counsel reasonably satisfactory to the indemnified party; or (iii) the named parties in any such proceeding (including any impleaded parties) include both the indemnified party and the indemnifying party, and representation of both sets of parties by the same counsel would be inappropriate due to actual or potential differing interests between them; *provided further* , however, that the indemnifying party shall not, in connection with any one such claim or action or separate but substantially similar or related claims or actions in the same jurisdiction, arising out of the same general allegations or circumstances, be liable for the legal or other expenses of more than one separate firm of attorneys (in addition to local counsel) for all of the indemnified parties, which firm shall be designated in writing by the Company or the Representatives, as applicable, and that all such legal or other expenses shall be reimbursed as they are incurred. No indemnifying party shall (i) without the prior written consent of the indemnified parties, settle or compromise or consent to the entry of any judgment with respect to any pending or threatened claim, action, suit or proceeding in respect of which indemnification or contribution may be sought hereunder (whether or not the indemnified parties are actual or potential parties to such claim or action) unless such settlement, compromise or consent includes an unconditional release of each indemnified party from all liability arising out of such claim, action, suit or proceeding, provided that such unconditional release may be subject to parallel release by a claimant or plaintiff of such indemnified party, and does not include any findings of fact or admissions of fault or culpability as to the indemnified party, or (ii) be liable for any settlement of any such action effected without its written consent, but if settled with the consent of the indemnifying party or if there be a final judgment for the plaintiff in any such action, the indemnifying party agrees to indemnify and hold harmless any indemnified party from and against any loss or liability by reason of such settlement or judgment.

(d) If the indemnification provided for in this Section 8 shall for any reason be unavailable to or insufficient to hold harmless an indemnified party under Section 8(a) or 8(b) in respect of any loss, claim, damage or liability, or any action in respect thereof, referred to therein, then each indemnifying party shall, in lieu of indemnifying such indemnified party, contribute to the amount paid or payable by such indemnified party as a result of such loss, claim, damage or liability, or action in respect thereof, (i) in such proportion as shall be appropriate to reflect the relative benefits received by the Company, on the one hand, and the Underwriters, on the other, from the offering of the Securities or (ii) if the allocation provided by clause (i) above is not permitted by applicable law, in such proportion as is appropriate to reflect not only the relative benefits referred to in clause (i) above but also the relative fault of the Company, on the one hand, and the Underwriters, on the other, with respect to the statements or omissions that resulted in such loss, claim, damage or liability, or action in respect thereof, as well as any other relevant equitable considerations. The relative benefits received by the Company, on the one hand, and the Underwriters, on the other, with respect to such offering shall be deemed to be in the same proportion as the total net proceeds from the offering of the Securities purchased under this Agreement (before deducting expenses) received by the Company, as set forth in the table on the cover page of the Prospectus, on the one hand, and the total underwriting discounts and commissions received by the Underwriters with respect to the aggregate principal amount of Securities purchased under this Agreement, as set forth in the table on the cover page of the Prospectus, on the other hand. The relative fault shall be determined by reference to whether the untrue or alleged untrue statement of a material fact or omission or alleged omission to state a material fact relates to information supplied by the Company or the Underwriters, the intent of the parties and their relative knowledge, access to information and opportunity to correct or prevent such statement or omission. The Company and the Underwriters agree that it would not be just and equitable if contributions pursuant to this Section (d) were to be determined by pro rata allocation (even if the Underwriters were treated as one entity for such purpose) or by any other method of allocation that does not take into account the equitable considerations referred to herein. The amount paid or payable by an indemnified party as a result of the loss, claim, damage or liability, or action in respect thereof, referred to above in this Section (d) shall be deemed to include, for purposes of this Section (d) , any legal or other expenses reasonably incurred by such indemnified party in connection with investigating or defending any such action. Notwithstanding the provisions of this Section (d) , no Underwriter shall be required to contribute any amount in excess of the amount by which the net proceeds from the sale of the Securities underwritten by it exceeds the amount of any damages that such Underwriter has otherwise paid or become liable to pay by reason of any untrue or alleged untrue statement or omission or alleged omission. No person guilty of fraudulent misrepresentation (within the meaning of Section 11 (f) of the Securities Act) shall be entitled to contribution from any person who was not guilty of such fraudulent misrepresentation. The Underwriters' obligations to contribute as provided in this Section (d) are several in proportion to their respective underwriting obligations and not joint.

(e) The Underwriters severally confirm and the Company acknowledges and agrees that the statements regarding the concession and reallowance figures and the paragraph relating to stabilization by the Underwriters appearing under the caption "Underwriting" in the most recent Preliminary Prospectus and the Prospectus constitute the only information concerning such Underwriters furnished in writing to the Company by or on behalf of the Underwriters specifically for inclusion in any Preliminary Prospectus, the Registration Statement, the Prospectus, any Issuer Free Writing Prospectus or in any amendment or supplement thereto.

9. *Defaulting Underwriters* . If, on the Delivery Date, any Underwriter shall fail or refuse to purchase the principal amount of Securities agreed to be purchased by such Underwriter hereunder, the remaining non-defaulting Underwriters shall be obligated to purchase the principal amount of Securities that the defaulting Underwriter agreed but failed to purchase on such Delivery Date in the respective proportions which the principal amount of Securities set forth opposite the name of each remaining non-defaulting Underwriter in Schedule I hereto bears to the aggregate principal amount of Securities set forth opposite the names of all the remaining non-defaulting Underwriters in Schedule I hereto; *provided, however* , that the remaining non-defaulting Underwriters shall not be obligated to purchase any of the Securities on such Delivery Date if the aggregate principal amount of Securities that the defaulting Underwriter or Underwriters agreed but failed to purchase on such date exceeds 9.09% of the aggregate principal amount of Securities to be purchased on such Delivery Date, and any remaining non-defaulting Underwriter shall not be obligated to purchase more than 110% of the principal amount of Securities that it agreed to purchase on such Delivery Date pursuant to the terms of Section 2 . If the foregoing maximums are exceeded, the remaining non-defaulting Underwriters, or those other underwriters satisfactory to the Representatives who so agree, shall have the right, but shall not be obligated, to purchase, in such proportion as may be agreed upon among them, all the Securities to be purchased on such Delivery Date. If the remaining Underwriters or other underwriters satisfactory to the Representatives do not elect to purchase the Securities that the defaulting Underwriter or Underwriters agreed but failed to purchase on such Delivery Date, this Agreement shall terminate without liability on the part of any non-defaulting Underwriter or the Company, except that the Company will continue to be liable for the payment of expenses to the extent set forth in, and subject to the terms of, Sections 6 and 11. As used in this Agreement, the term "Underwriter" includes, for all purposes of this Agreement unless the context requires otherwise, any party not listed in Schedule I hereto that, pursuant to this Section 9 , purchases Securities that a defaulting Underwriter agreed but failed to purchase.

Nothing contained herein shall relieve a defaulting Underwriter of any liability it may have to the Company for damages caused by its default. If other Underwriters are obligated or agree to purchase the Securities of a defaulting or withdrawing Underwriter, either the Representatives or the Company may postpone the Delivery Date for up to seven full business days in order to effect any changes that in the opinion of counsel for the Company or counsel for the Underwriters may be necessary in the Registration Statement, the Prospectus or in any other document or arrangement.

10. *Termination* . The obligations of the Underwriters hereunder may be terminated by the Representatives by notice given to and received by the Company prior to delivery of and payment for the Securities if, prior to that time, any of the events described in Sections 7(j) and 7(k) shall have occurred.

11. *Reimbursement of Underwriters' Expenses* . If the Company shall fail to tender the Securities for delivery to the Underwriters by reason of any failure, refusal or inability on the part of the Company to perform any agreement on its part to be performed, or if any other condition to the Underwriters' obligations hereunder required to be fulfilled by the Company is not fulfilled for any reason, the Company will reimburse the Underwriters for all reasonable out-of-pocket expenses (including reasonable fees and disbursements of counsel) incurred by the Underwriters in connection with this Agreement and the proposed purchase of the Securities, and upon demand the Company shall pay the full amount thereof to the Representatives.

12. *Research Analyst Independence* . The Company acknowledges that the Underwriters' research analysts and research departments are required to be independent from their respective investment banking divisions and are subject to certain regulations and internal policies, and that such Underwriters' research analysts may hold views and make statements or investment recommendations and/or publish research reports with respect to the Company and/or the offering that differ from the views of their respective investment banking divisions. The Company hereby waives and releases, to the fullest extent permitted by law, any claims that the Company may have against the Underwriters with respect to any conflict of interest that may arise from the fact that the views expressed by their independent research analysts and research departments may be different from or inconsistent with the views or advice communicated to the Company by such Underwriters' investment banking divisions. The Company acknowledges that each of the Underwriters is a full service securities firm and as such from time to time, subject to applicable securities laws, may effect transactions for its own account or the account of its customers and hold long or short positions in debt or equity securities of the companies that may be the subject of the transactions contemplated by this Agreement.

13. *No Fiduciary Duty* . The Company acknowledges and agrees that in connection with this offering, sale of the Securities or any other services the Underwriters may be deemed to be providing hereunder, notwithstanding any preexisting relationship, advisory or otherwise, between the parties or any oral representations or assurances previously or subsequently made by the Underwriters: (i) no fiduciary or agency relationships between the Company and any other person, on the one hand, and the Underwriters, on the other, exist; (ii) the Underwriters are not acting as advisors, expert or otherwise, to the Company, including, without limitation, with respect to the determination of the public offering price of the Securities, and such relationship between the Company on the one hand, and the Underwriters, on the other, is entirely and solely commercial, based on arms-length negotiations; (iii) any duties and obligations that the Underwriters may have to the Company shall be limited to those duties and obligations specifically stated herein; and (iv) the Underwriters and their respective affiliates may have interests that differ from those of the Company. The Company hereby waives any claims that the Company may have against the Underwriters with respect to any breach of fiduciary duty in connection with this offering.

14. *Notices, Etc* . All statements, requests, notices and agreements hereunder shall be in writing, and:

(a) if to the Underwriters, shall be delivered or sent by mail or facsimile transmission to the Representatives at J.P. Morgan Securities LLC, 383 Madison Avenue, New York, NY 10179, Attention: Investment Grade Syndicate Desk (Fax: (212) 834-6081), Mitsubishi UFJ Securities (USA), Inc., 1633 Broadway, 29 th Floor, New York, NY 10019, Attention: Capital Markets Group (Fax: (646) 434-3455) and U.S. Bancorp Investments, Inc., 214 N. Tryon St., EX-NC-WSTC, Charlotte, NC 28202 Attention: High Grade Syndicate (Fax: (877) 774-3462), with a copy to Shearman & Sterling LLP, 599 Lexington Avenue, New York, NY 10021, Attention: Lisa L. Jacobs (Fax: (646) 848-7678); and

(b) if to the Company, shall be delivered or sent by mail or facsimile transmission to the address of the Company set forth in the Registration Statement, Attention: Louis P. Gregory (Fax: (972) 855-3080).

Any such statements, requests, notices or agreements shall take effect at the time of receipt thereof. The Company shall be entitled to act and rely upon any request, consent, notice or agreement given or made on behalf of the Underwriters by the Representatives.

15. *Persons Entitled to Benefit of Agreement* . This Agreement shall inure to the benefit of and be binding upon the Underwriters, the Company, any controlling person referred to herein, the other indemnitees referred to herein and their respective successors and assigns, all as and to the extent provided in this Agreement, and no other person shall acquire or have any legal or equitable right, remedy or claim under or in respect of this Agreement or any provision contained herein. The term "successors and assigns" shall not include a purchaser of Securities from any Underwriter merely because of such purchase.

16. *Survival* . The respective indemnities, representations, warranties and agreements of the Company and the Underwriters contained in this Agreement or made by or on behalf of them, respectively, pursuant to this Agreement, shall survive the delivery of and payment for the Securities and shall remain in full force and effect, regardless of any investigation made by or on behalf of any of them or any person controlling any of them.

17. *Definition of the Term "Business Day* ." For purposes of this Agreement " **business day** " means each Monday, Tuesday, Wednesday, Thursday or Friday that is not a day on which banking institutions in New York are generally authorized or obligated by law or executive order to close.

18. *Governing Law.* This Agreement shall be governed by and construed in accordance with the laws of the State of New York.

19. *Counterparts.* This Agreement may be executed in one or more counterparts and, if executed in more than one counterpart, the executed counterparts shall each be deemed to be an original but all such counterparts shall together constitute one and the same instrument.

20. *Headings* . The headings herein are inserted for convenience of reference only and are not intended to be part of, or to affect the meaning or interpretation of, this Agreement.

21. *Patriot Act.* In accordance with the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)), the Underwriters are required to obtain, verify and record information that identifies their respective clients, including the Company, which information may include the name and address of their respective clients, as well as other information that will allow the Underwriters to properly identify their respective clients.

If the foregoing correctly sets forth the agreement among the Company and the Underwriters, please indicate your acceptance in the space provided for that purpose below.

Very truly yours,

ATMOS ENERGY CORPORATION

By: /s/ BRET J. ECKERT
Name: Bret J. Eckert
Title: Senior Vice President and Chief Financial Officer

Signature Page to the Underwriting Agreement

Accepted, as of the date first above written:

J.P. M ORGAN S ECURITIES LLC
M ITSUBISHI UFJ S ECURITIES (USA), I NC .
U.S. B ANCORP I NVESTMENTS , I NC .
Acting on behalf of themselves
and as the Representatives of
the several Underwriters

J.P. M ORGAN S ECURITIES LLC

By: /s/ ROBERT BOTTAMEDI
Name: Robert Bottamedi
Title: Vice President

M ITSUBISHI UFJ S ECURITIES (USA), I NC .

By: /s/ BRIAN COGLIANDRO
Name: Brian Cogliandro
Title: Managing Director

U.S. B ANCORP I NVESTMENTS , I NC .

By: /s/ CRAIG ANDERSON
Name: Craig Anderson
Title: Senior Vice President

Signature Page to the Underwriting Agreement

SCHEDULE I

Underwriters	Principal Amount of Securities
J.P. Morgan Securities LLC	$ 80,000,000
Mitsubishi UFJ Securities (USA), Inc.	80,000,000
U.S. Bancorp Investments, Inc.	80,000,000
Credit Agricole Securities (USA) Inc.	50,000,000
RBS Securities Inc.	50,000,000
BNP Paribas Securities Corp.	25,000,000
Merrill Lynch, Pierce, Fenner & Smith Incorporated	25,000,000
UBS Securities LLC	25,000,000
Wells Fargo Securities, LLC	25,000,000
BB&T Capital Markets, a division of BB&T Securities, LLC	15,000,000
BOSC, Inc.	15,000,000
Goldman, Sachs & Co.	15,000,000
Morgan Stanley & Co. LLC	15,000,000
Total	$ 500,000,000

SCHEDULE II

GENERAL USE ISSUER FREE WRITING PROSPECTUS

The General Use Issuer Free Writing Prospectus(es) included in the Disclosure Package includes each of the following:

1. Final Term Sheet dated January 8, 2013, a copy of which is attached as Exhibit A to this Agreement substantially in the form filed with the Commission.

Schedule II

SCHEDULE III

LIST OF ALL SUBSIDIARIES

Atmos Energy Holdings, Inc.
Atmos Energy Marketing, LLC
Atmos Energy Services, LLC
Atmos Exploration and Production, Inc.
Atmos Gathering Company, LLC
Atmos Pipeline and Storage, LLC
Atmos Power Systems, Inc.
Blueflame Insurance Services, LTD
Egasco, LLC
Fort Necessity Gas Storage, LLC
Phoenix Gas Gathering Company
Trans Louisiana Gas Pipeline, Inc.
Trans Louisiana Gas Storage, Inc.
UCG Storage, Inc.
WKG Storage, Inc.

Schedule III

SCHEDULE IV

LIST OF SIGNIFICANT SUBSIDIARIES

None

Schedule IV

EXHIBIT A

Filed Pursuant to Rule 433 under the Securities Act of 1933
Registration Statement No. 333-165818
Issuer Free Writing Prospectus, dated January 8, 2013

ATMOS ENERGY CORPORATION
4.15% Senior Notes due 2043

This Free Writing Prospectus relates only to the 4.15% Senior Notes due 2043 of Atmos Energy Corporation and should be read together with the Preliminary Prospectus Supplement dated January 8, 2013 relating to the 4.15% Senior Notes due 2043.

Issuer:	Atmos Energy Corporation
Security Description:	Senior Unsecured Notes
Principal Amount:	$500,000,000
Maturity Date:	January 15, 2043
Trade Date:	January 8, 2013
Settlement Date:	January 11, 2013; T+3
Interest Payment Dates:	Semi-annually in arrears on January 15 and July 15, beginning July 15, 2013
Coupon:	4.15%
Benchmark Treasury:	2.750% due August 15, 2042
Benchmark Treasury Yield:	3.061%
Spread to Benchmark Treasury:	+110 basis points
Yield to Maturity:	4.161%
Public Offering Price:	99.812% per Note
Optional Redemption Provisions:	The Notes may be redeemed, at the option of Atmos Energy Corporation, at any time in whole or from time to time in part. Prior to July 15, 2042, the redemption price will be equal to the greater of (i) 100% of the principal amount of the Notes to be redeemed and (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the Notes to be redeemed discounted, on a semi-annual basis, at the make-whole call, plus, in each case, accrued interest to the date of redemption. At

	any time on or after July 15, 2042, the redemption price will be equal to 100% of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any, to the redemption date.
Make-Whole Call:	Make whole call at T+ 20 basis points
CUSIP/ISIN:	049560 AL9 / US049560AL95
Joint Book-Running Managers:	J.P. Morgan Securities LLC Mitsubishi UFJ Securities (USA), Inc. U.S. Bancorp Investments, Inc. Credit Agricole Securities (USA) Inc. RBS Securities Inc.
Senior Co-Managers:	BNP Paribas Securities Corp. Merrill Lynch, Pierce, Fenner & Smith Incorporated UBS Securities LLC Wells Fargo Securities, LLC
Co-Managers:	BB&T Capital Markets, a division of BB&T Securities, LLC BOSC, Inc. Goldman, Sachs & Co Morgan Stanley & Co. LLC

Atmos Energy Corporation has filed a registration statement (including a prospectus) with the SEC for the offering to which this communication relates. Before you invest, you should read the prospectus in that registration statement and other documents the issuer has filed with the SEC for more complete information about Atmos Energy Corporation and this offering. You may get these documents for free by visiting EDGAR on the SEC Web site at www.sec.gov. Alternatively, any underwriter or any dealer participating in the offering will arrange to send you the prospectus if you request it by calling J.P. Morgan Securities LLC collect at 212-834-4533, Mitsubishi UFJ Securities (USA), Inc. at 877-649-6848 or U.S. Bancorp Investments, Inc. at 877-558-2607.

Exhibit A-2

EXHIBIT B-1

FORM OF OPINION OF VIRGINIA COUNSEL TO THE COMPANY
TO BE DELIVERED PURSUANT TO
SECTION 7(c)

1. The Company is validly existing as a corporation in good standing under the laws of the Commonwealth of Virginia.

2. The Company has corporate power and authority to own, lease and operate its properties and to conduct its business as described in the Preliminary Prospectus and the Prospectus and to enter into and perform its obligations under the Underwriting Agreement (including without limitation, issuing the Securities), the Indenture (as modified by the Section 301 Officers' Certificate) and the Securities.

3. Each of the Underwriting Agreement, Indenture and the Section 301 Officers' Certificate has been duly authorized, executed and delivered by the Company.

4. The Securities have been duly authorized, executed and delivered by the Company.

Such counsel is aware that this opinion will be relied upon by U.S. Bank National Association, as Trustee under, and in connection with the transactions contemplated by the Indenture.

* * *

In rendering such opinion, such counsel may state that its opinion is limited to the Federal laws of the United States and the laws of the Commonwealth of Virginia.

EXHIBIT B-2

FORM OF OPINIONS AND LETTER OF GENERAL COUNSEL OF THE COMPANY
TO BE DELIVERED PURSUANT TO
SECTION 7(d)

1. The Company has been duly organized and is validly existing as a corporation in good standing under the laws of the State of Texas and the Commonwealth of Virginia.

2. The Company is duly qualified as a foreign corporation to transact business and is in good standing in each jurisdiction in which such qualification is required, whether by reason of the ownership or leasing of property or the conduct of business, except where the failure so to qualify or to be in good standing would not result in a Material Adverse Effect.

3. The information in the Registration Statement under Item 15, to the extent that it constitutes matters of law, summaries of legal matters or legal conclusions, has been reviewed by me and is correct in all material respects.

4. The authorized, issued and outstanding capital stock of the Company is as set forth in the most recent Preliminary Prospectus and the Prospectus under the caption "Capitalization" (except for subsequent issuances, if any, pursuant to reservations, agreements or employee benefit plans referred to in the most recent Preliminary Prospectus and the Prospectus or pursuant to the exercise of options or share unit awards referred to in the most recent Preliminary Prospectus and the Prospectus); the shares of issued and outstanding capital stock of the Company have been duly authorized and validly issued and are fully paid and non-assessable; and none of the outstanding shares of capital stock of the Company was issued in violation of the preemptive or other similar rights of any securityholder of the Company.

5. The Underwriting Agreement has been duly authorized, executed and delivered by the Company.

6. Each of the Securities and the Indenture has been duly authorized, executed and delivered by the Company. The Section 301 Officers' Certificate has been duly authorized by the Company and duly executed and delivered by two officers of the Company.

7. The documents incorporated by reference in the Registration Statement, the most recent Preliminary Prospectus and the Prospectus (other than financial statements and schedules and other information of an accounting or financial nature included or incorporated by reference therein, as to which I express no opinion or belief), when they were filed with the Commission, complied as to form in all material respects with the requirements of the Exchange Act and the rules and regulations under the Exchange Act.

8. To the best of my knowledge, there is no pending or threatened action, suit, proceeding, inquiry or investigation, to which the Company or any subsidiary is a party, or to which the property of the Company or any subsidiary is subject, before or brought by any court or governmental agency or body, domestic or foreign, which might reasonably be expected to result in a Material Adverse Effect, or which might reasonably be expected to have a Material Adverse Effect on the properties or assets thereof or the consummation of the transactions contemplated in the Underwriting Agreement or the performance by the Company of its obligations thereunder, or which is required to be described in the most recent Preliminary Prospectus and the Prospectus that is not described as required.

9. The information in (a) the most recent Preliminary Prospectus and the Prospectus under "Business – Other Regulation," "Description of the Notes," or "Description of Debt Securities," (b) the Annual Report on Form 10-K for the fiscal year ended September 30, 2012 (the "10-K") under "Item 1. – Business – Ratemaking Activity," under "Item 1. – Business – Other Regulation" or under "Item 3. – Legal Proceedings" and (c) "Note 12. – Commitments and Contingencies" to the Company's consolidated financial statements included in the 10-K, to the extent that it constitutes matters of law, summaries of legal matters, the Company's articles of incorporation and bylaws or legal proceedings, or legal conclusions, has been reviewed by me and is correct in all material respects.

10. All descriptions in the Registration Statement, the most recent Preliminary Prospectus and the Prospectus of contracts and other documents to which the Company or its subsidiaries are a party are accurate in all material respects; to the best of my knowledge, there are no franchises, contracts, indentures, mortgages, loan agreements, notes, leases or other instruments required to be described or referred to in the Registration Statement, the most recent Preliminary Prospectus or the Prospectus or to be filed as exhibits thereto other than those described or referred to therein or filed or incorporated by reference as exhibits thereto, and the descriptions thereof or references thereto are correct in all material respects.

11. To the best of my knowledge, (i) neither the Company nor any subsidiary is in violation of its charter, bylaws or other organizational document and (ii) no default by the Company or any subsidiary exists in the due performance or observance of any material obligation, agreement, covenant or condition contained in any contract, indenture, mortgage, loan agreement, note, lease or other agreement or instrument that is described or referred to in the Registration Statement, the most recent Preliminary Prospectus or the Prospectus or filed or incorporated by reference as an exhibit to the Registration Statement, except with respect to (ii) above, for such defaults that would not result in a Material Adverse Effect.

12. There have been issued and, as of the date hereof, are in full force and effect orders or authorizations of the regulatory authorities of Colorado, Georgia, Kentucky and Virginia authorizing the issuance and sale of the Securities by the Company on the terms set forth or contemplated in the Underwriting Agreement and the Indenture; and no other filing with, or authorization, approval, consent, license, order, registration, qualification or decree of, any court or governmental authority or agency, domestic or foreign (other than under the Securities Act, the Exchange Act and the Rules and Regulations, which have been obtained, or as may be required under the securities or blue sky laws of the various states, as to which I express no opinion), is necessary or required in connection with the due authorization, execution and delivery of the Underwriting Agreement, the Indenture or the Securities, or for the offering, issuance, sale or delivery of the Securities by the Company pursuant to the Underwriting Agreement.

13. The execution, delivery and performance of the Underwriting Agreement, the Indenture and the Securities by the Company and the consummation of the transactions contemplated in the Underwriting Agreement and the Indenture and in the Registration Statement, the most recent Preliminary Prospectus and the Prospectus (including the issuance and sale of the Securities by the Company and the use of the proceeds from the sale of the Securities as described in the Prospectus under the caption "Use of Proceeds") and compliance by the Company with its obligations under the Underwriting Agreement, the Indenture and the Securities do not and will not, whether with or without the giving of notice or lapse of time or both, violate or constitute a breach of, or default under, or result in the creation or imposition of any lien, charge or encumbrance upon any property or assets of the Company or any subsidiary pursuant to, any contract, indenture, mortgage, deed of trust, loan or credit agreement, note, lease or any other agreement or instrument, known to me, to which the Company or any subsidiary is a party or by which it or any of them may be bound, or to which any of the property or assets of the Company or any subsidiary

is subject (except for such violations, breaches or defaults or liens, charges or encumbrances that would not have a Material Adverse Effect), nor will such action result in any violation of the provisions of the articles of incorporation or bylaws of the Company or the charter, bylaws or other organizational documents of any subsidiary, or any applicable law, statute, rule, regulation, judgment, order, writ or decree, known to me, of any government, government instrumentality or court, domestic or foreign, binding on the Company or any subsidiary or any of their respective properties, assets or operations. I express no opinion in this paragraph regarding federal or state securities laws.

Except for the financial statements and related notes and schedules and other information of an accounting or financial nature included or incorporated by reference therein, as to which I express no opinion or belief, no facts have come to my attention that led me to believe: (a) that the Registration Statement, at the time it became effective (which shall have the meaning set forth in Rule 158(c) of the Rules and Regulations) or the Prospectus, as of its date, were not appropriately responsive in all material respects to the requirements of the Securities Act and the Rules and Regulations; or (b)(i) that the Registration Statement, at the time it became effective, contained a untrue statement of a material fact or omitted to state a material fact required to be stated therein or necessary to make the statements therein not misleading, (ii) that the Pricing Disclosure Package, as of the Applicable Time, contained any untrue statement of a material fact or omitted to state any material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; or (iii) that the Prospectus, as of its date or the date hereof, contained or contains an untrue statement of a material fact or omitted or omits to state a material fact necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading.

Such counsel is aware that this opinion will be relied upon by U.S. Bank National Association, as Trustee under, and in connection with the transactions contemplated by the Indenture.

* * *

In rendering such opinion, such counsel may state that his opinion is limited to the Federal laws of the United States, the laws of the State of Texas and the Virginia Stock Corporation Act.

Exhibit B-2-3

Exhibit 4.1

ATMOS ENERGY CORPORATION

Officers' Certificate Pursuant to Section 301 of the Indenture

January , 2013

Each of the undersigned, Bret J. Eckert, Senior Vice President and Chief Financial Officer, and Louis P. Gregory, Senior Vice President, General Counsel and Corporate Secretary of Atmos Energy Corporation (the "Company") certifies, pursuant to the authority delegated to each of them, as an officer of the Company, pursuant to the resolutions adopted by the board of directors of the Company (the "Board") on November 6, 2012 (copies of which resolutions are attached hereto as Exhibit I), that pursuant to Section 301 of the Indenture dated as of March 26, 2009 (the "Indenture") between the Company and U.S. Bank National Association, as trustee (the "Trustee"), a series of debt securities of the Company is hereby established with the following terms and provisions (unless otherwise defined herein, capitalized terms used herein have the meaning given thereto in the Indenture):

1. The title of the series of the securities is the 4.15% Senior Notes due 2043 (the "Notes").

2. The Notes are unsubordinated and will rank equally with all of the Company's other unsecured and unsubordinated debt. Subordinated debt will rank junior to the Notes and the Company's other senior debt.

3. The aggregate principal amount of the Notes that may be issued under the Indenture, in connection with the Underwriting Agreement, dated as of January 8, 2013, between the Company and certain underwriters named therein, is $500,000,000, and the Stated Maturity of the Notes is January 15, 2043. The Notes shall be offered to the public at a price representing 99.812% of their principal amount.

4. The Notes shall bear interest at the rate of 4.15% per annum. Interest on the Notes will be payable in arrears on January 15 and July 15 of each year (each, an "Interest Payment Date"), beginning July 15, 2013. Interest payable on each Interest Payment Date will include interest accrued from and including January 11, 2013, or from and including the most recent Interest Payment Date to which interest has been paid or duly provided for, as the case may be, to but excluding such Interest Payment Date. Interest will be computed on the basis of a 360-day year of twelve 30-day months. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in the Indenture, be paid to the Holder in whose name the Notes are registered at the close of business on the January 1 or July 1 (whether or not a Business Day) preceding the respective Interest Payment Date. The payment of any Defaulted Interest on the Notes shall be payable to the Holders of the Notes on a Special Record Date established therefor pursuant to the Indenture, or shall be paid at any time in any other lawful manner, all as more fully provided in the Indenture.

5. Payment of the principal of (and premium, if any) and interest on the Notes will be made at the office or agency of the Company maintained for that purpose in the Borough of Manhattan, the City of New York, or at such other office or agency of the Company as may be maintained for such purpose, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. So long as the Notes remain in book-entry form, all payments of principal and interest will be made by the Company in immediately available funds.

6. The Company may redeem the Notes prior to maturity at its option, at any time in whole or from time to time in part. Prior to July 15, 2042, the Redemption Price shall be equal to the greater of:

(a) 100% of the principal amount of the Notes to be redeemed, and

(b) as determined by the Quotation Agent (as defined below), the sum of the present values of the Remaining Scheduled Payments (as defined below) of principal and interest on the Notes to be redeemed discounted to the Redemption Date on a semi-annual basis assuming a 360-day year consisting of twelve 30-day months at the Adjusted Treasury Rate (as defined below) plus 20 basis points;

plus, in each case, accrued and unpaid interest on the principal amount of Notes being redeemed to the Redemption Date.

At any time on or after July 15, 2042, the Redemption Price shall be equal to 100% of the principal amount of the Notes to be redeemed, plus accrued and unpaid interest thereon to the Redemption Date.

"Adjusted Treasury Rate" means, for any Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price of the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that Redemption Date;

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the Notes to be redeemed that would be used, at the time of a selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Notes to be redeemed;

"Comparable Treasury Price" means, for any Redemption Date, the average of the Reference Treasury Dealer Quotations for that Redemption Date;

"Quotation Agent" means the Reference Treasury Dealer appointed by the Company to act as a quotation agent;

"Reference Treasury Dealer" means (i) J.P. Morgan Securities LLC and any Primary Treasury Dealer (as defined below) selected by each of Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc., and any of such parties' successors; provided, however, if any of the foregoing ceases to be a primary U.S. government securities dealer in New York City (a "Primary Treasury Dealer"), the Company will substitute therefor another Primary Treasury Dealer, and (ii) any other Primary Treasury Dealer selected by the Company;

"Reference Treasury Dealer Quotation" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed, in each case, as a percentage of its principal amount) quoted in writing to the Trustee at 5:00 p.m., Eastern time by such Reference Treasury Dealer on the third Business Day preceding such Redemption Date; and

"Remaining Scheduled Payments" means, with respect to each Note to be redeemed, the remaining scheduled payments of the principal and interest on such Note that would be due after the related Redemption Date but for such redemption; provided, however, that if such Redemption Date is not an Interest Payment Date, the amount of the next succeeding scheduled interest payment on such Note will be reduced by the amount of interest accrued on such Note to such Redemption Date.

7. In the case of a partial redemption of the Notes, the Notes to be redeemed shall be selected by the Trustee from the outstanding Notes not previously called for redemption, by such method as the Trustee shall deem fair and appropriate (or, in the case of notes issued in global form, by such method as the depository may require) and which may provide for the selection for redemption of portions of the principal of the Notes. A partial redemption shall not reduce the portion of the principal amount of a Note not redeemed to a principal amount of less than $2,000. Notice of any redemption will be mailed by first class mail at least 30 days but not more than 60 days before the Redemption Date to each Holder of the Notes to be redeemed at its registered address. If any Notes are to be redeemed in part only, the notice of redemption will state the portion of the principal amount of the Notes to be redeemed. A new Note in a principal amount equal to the unredeemed portion of the Note will be issued in the name of the Holder of the Note upon surrender for cancellation of the original Note. Unless the Company defaults in payment of the Redemption Price, on and after the Redemption Date, interest will cease to accrue on the Notes or the portions of the Notes called for redemption.

8. Section 703 of the Indenture is replaced with the following in its entirety for purposes of the Notes only:

The Company shall:

(1) file with the Trustee, within 30 days after the Company has filed the same with the Commission, unless such reports are available on the Commission's EDGAR filing system (or any successor thereto), copies of the annual reports and of the information, documents and other reports (or copies of such portions of any of the foregoing as the Commission may from time to time by rules and regulations prescribe) which the Company may be required to file with the Commission pursuant to Section 13 or Section 15(d) of the Exchange Act; or, if the Company is not required to file information, documents or reports pursuant to either of such Sections, then the Company shall file with the Trustee and the Commission, in accordance with rules and regulations prescribed from time to time by the Commission, such of the supplementary and periodic

information, documents and reports which may be required pursuant to Section 13 of the Exchange Act in respect of a security listed and registered on a national securities exchange as may be prescribed from time to time in such rules and regulations;

(2) file with the Trustee and the Commission, in accordance with rules and regulations prescribed from time to time by the Commission, such additional information, documents and reports with respect to compliance by the Company with the conditions and covenants of this Indenture as may be required from time to time by such rules and regulations; and

(3) transmit to all Holders, as their names and addresses appear in the Security Register, within 30 days after the filing thereof with the Trustee, in the manner and to the extent provided in TIA Section 313(c), such summaries of any information, documents and reports required to be filed by the Company pursuant to Subsections (1) and (2) of this Section 703 as may be required by rules and regulations prescribed from time to time by the Commission.

9. The Company has no obligation to redeem, purchase or repay the Notes pursuant to any mandatory redemption or sinking fund or analogous provisions or at the option of the Holder thereof.

10. The entire $500,000,000 principal amount of the Notes shall be payable upon declaration of acceleration of the Maturity thereof pursuant to the Indenture.

11. The defeasance and covenant defeasance provisions of Article Fourteen of the Indenture shall apply to the Notes.

12. The Trustee, the initial Paying Agent and the initial Security Registrar for the Notes shall be U.S. Bank National Association. The Security Register for the Notes shall be initially maintained at, and the place where such Notes may be surrendered for registration of transfer or exchange shall be, the Trustee's Corporate Trust Office located at 1349 West Peachtree Street, Suite 1050, Atlanta, Georgia.

13. The Notes will be issued in registered permanent global form and each evidenced by a global security (a "Global Security") in substantially the form attached hereto as Exhibit II, with such appropriate insertions, omissions, substitutions and other variations as are required or permitted by the Indenture, and may have imprinted or otherwise reproduced thereon such legend or legends or endorsements, not inconsistent with the provisions of the Indenture, as may be required to comply with any law or with any rules or regulations pursuant thereto, or with any rules of any securities exchange or to conform to general usage, all as may be determined by the officers executing each such Global Security, as evidenced by their execution of such Global Security. The beneficial owners of interests in each of the Global Securities may exchange such interests for Notes, as applicable, in certificated form (the "Definitive Notes") only in limited circumstances as provided in the Indenture. In the event that Definitive Notes are issued in exchange for a Global Security, the form of certificate evidencing each Definitive Note shall be in substantially the form of the attached Global Security, with such changes as are necessary to evidence the Notes in definitive form rather than as a Global Security. The Company initially appoints DTC to act as Depository with respect to the Notes.

14. The Notes are issuable in denominations of $2,000 and any integral multiples of $1,000 in excess thereof.

15. The Events of Default set forth in the Indenture shall apply to the Notes.

16. The Company will not pay Additional Amounts on the Notes held by any Holder who is not a United States person in respect of any tax, assessment or governmental charge withheld or deducted.

15. The Company may, at any time, without the consent of the Holders of the Notes, create and issue additional securities having the same ranking, interest rate, maturity and other terms as the Notes. Any such additional securities shall be consolidated and form the same series of the Notes having the same terms as to status, redemption and otherwise as the Notes under the Indenture.

Each of us further certifies that the form and terms of the Notes as established in this certificate have been established pursuant to Section 301 of the Indenture and comply with the Indenture.

[Signature page follows]

IN WITNESS WHEREOF, I have executed this certificate as of the date first written above.

By:______________________________
Name: Bret J. Eckert
Title: Senior Vice President and Chief Financial Officer

IN WITNESS WHEREOF, I have executed this certificate as of the date first written above.

By:______________________________
Name: Louis P. Gregory
Title: Senior Vice President, General Counsel and Corporate Secretary

Officers' Certificate Pursuant to Section 301 of the Indenture

Exhibit 4.2

THIS SECURITY IS A GLOBAL SECURITY WITHIN THE MEANING OF THE INDENTURE HEREINAFTER REFERRED TO AND IS REGISTERED IN THE NAME OF A DEPOSITORY OR A NOMINEE THEREOF. THIS SECURITY MAY NOT BE EXCHANGED IN WHOLE OR IN PART FOR A SECURITY REGISTERED, AND NO TRANSFER OF THIS SECURITY IN WHOLE OR IN PART MAY BE REGISTERED, IN THE NAME OF ANY PERSON OTHER THAN SUCH DEPOSITORY OR ITS NOMINEE EXCEPT IN THE LIMITED CIRCUMSTANCES DESCRIBED IN THE INDENTURE.

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (55 WATER STREET, NEW YORK, NEW YORK) TO THE ISSUER OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND SUCH CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO., OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY, ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL, SINCE THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

ATMOS ENERGY CORPORATION

4.15% Senior Notes due 2043

No. 1

CUSIP NO. 049560 AL9
ISIN NO. US049560 AL95

Atmos Energy Corporation, a Texas and Virginia corporation (herein called the "Company", which term includes any successor entity under the Indenture, hereinafter defined), for value received, hereby promises to pay to Cede & Co. or registered assigns the principal sum of FIVE HUNDRED MILLION DOLLARS ($500,000,000) on January 15, 2043 (the "Maturity Date"), at the office or agency of the Company referred to below, and to pay interest thereon from January 11, 2013, or from the most recent Interest Payment Date to which interest has been paid or duly provided for, semiannually in arrears on January 15 and July 15 in each year (each, an "Interest Payment Date"), beginning July 15, 2013 at 4.15% per annum until the principal hereof is paid or duly provided for.

Any payment of principal or interest required to be made on a day that is not a Business Day need not be made on such day, but may be made on the next succeeding Business Day with the same force and effect as if made on such day and no interest shall accrue as a result of such delayed payment. Interest payable on each Interest Payment Date will include interest accrued from and including January 11, 2013, or from and including the most recent Interest Payment Date to which interest has been paid or duly provided for, as the case may be, to but excluding such Interest Payment Date. Interest will be computed on the basis of a 360-day year of twelve 30-day months.

The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in the Indenture, be paid to the person (the "Holder") in whose name this Security (or one or more Predecessor Securities) is registered at the close of business on the January 1 or July 1 (whether or not a Business Day) next preceding such Interest Payment Date (a "Regular Record Date"). Any such interest not so punctually paid or duly provided for ("Defaulted Interest") will forthwith cease to be payable to the Holder on such Regular Record Date and either may be paid to the Person in whose name this Security (or one or more Predecessor Securities) is registered at the close of business on a special record date (the "Special Record Date") for the payment of such Defaulted Interest to be fixed by the Trustee (referred to herein), notice whereof shall be given to the Holder of this Security not less than ten days prior to such Special Record Date, or may be paid at any time in any other lawful manner, all as more fully provided in the Indenture.

For purposes of this Security, "Business Day" means any day that, in the city of the principal Corporate Trust Office of the Trustee and in the City of New York, is neither a Saturday, Sunday, or legal holiday nor a day on which banking institutions are authorized or required by law or regulation to close.

Payment of the principal of (and premium, if any) and interest on this Security will be made at the office or agency of the Company maintained for that purpose in the Borough of Manhattan, the City of New York, or at such other office or agency of the Company as may be maintained for such purpose, in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. So long as this Security remains in book-entry form, all payments of principal and interest will be made by the Company in immediately available funds.

Unless the certificate of authentication hereon has been duly executed by the Trustee by manual signature, this Security shall not be entitled to any benefit under the Indenture, or be valid or obligatory for any purpose.

This Security is one of a duly authorized issue of securities of the Company, designated as the 4.15% Senior Notes due 2043 (the "Securities"), issued under an Indenture dated as of March 26, 2009, as it may be supplemented from time to time (referred to herein as the "Indenture"), between the Company and U.S. Bank National Association, as trustee (referred to herein as the "Trustee", which term includes any successor trustee under the Indenture with respect to the series of which this Security is a part). A reference is hereby made to the Indenture for a statement of the respective rights, limitations of rights, duties, obligations and immunities thereunder of the Company, the Trustee and the Holders of the Securities, and of the terms upon which the Securities are, and are to be, authenticated and delivered, except as otherwise provided herein.

The Securities are initially limited to $500,000,000 aggregate principal amount. The Company may, at any time, without the consent of the Holders of the Securities, create and issue additional securities having the same ranking, interest rate, maturity and other terms as the Securities. Any such additional securities shall be consolidated and form the same series of the Securities having the same terms as to status, redemption and otherwise as the Securities under the Indenture.

Events of Default . If an Event of Default shall occur and be continuing, the principal of all the Securities may be declared due and payable in the manner and with the effect provided in the Indenture.

Optional Redemption . The Securities will be redeemable prior to maturity at the Company's option, at any time in whole or from time to time in part. Prior to July 15, 2042, the Redemption Price will be equal to the greater of:

(a) 100% of the principal amount of the Securities to be redeemed, and

(b) as determined by the Quotation Agent, the sum of the present values of the Remaining Scheduled Payments of principal and interest on the Securities to be redeemed discounted to the Redemption Date on a semi-annual basis assuming a 360-day year consisting of twelve 30-day months at the Adjusted Treasury Rate plus 20 basis points;

plus, in each case, accrued and unpaid interest on the principal amount of Securities being redeemed to the Redemption Date.

At any time on or after July 15, 2042, the Redemption Price will be equal to 100% of the principal amount of the Securities to be redeemed, plus accrued and unpaid interest thereon to the Redemption Date.

"Adjusted Treasury Rate" means, for any Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price of the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that Redemption Date.

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term of the Securities to be redeemed that would be used, at the time of a selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Securities to be redeemed.

"Comparable Treasury Price" means, for any Redemption Date, the Reference Treasury Dealer Quotation for that Redemption Date.

"Quotation Agent" means the Reference Treasury Dealer appointed by the Company to act as a quotation agent.

"Reference Treasury Dealer" means (i) J.P. Morgan Securities LLC and any Primary Treasury Dealer (as defined below) selected by each of Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc., and any of such parties' successors; provided, however, if any of the foregoing ceases to be a primary U.S. government securities dealer in New York City (a "Primary Treasury Dealer"), the Company will substitute therefor another Primary Treasury Dealer, and (ii) any other Primary Treasury Dealer selected by the Company.

"Reference Treasury Dealer Quotation" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed, in each case, as a percentage of its principal amount) quoted in writing to the Trustee at 5:00 p.m., Eastern time by such Reference Treasury Dealer on the third Business Day preceding such Redemption Date.

"Remaining Scheduled Payments" means, with respect to each Security to be redeemed, the remaining scheduled payments of the principal and interest on such Security that would be due after the related Redemption Date but for such redemption; provided, however, that if such Redemption Date is not an Interest Payment Date, the amount of the next succeeding scheduled interest payment on such Security will be reduced by the amount of interest accrued on such Security to such Redemption Date.

In the event that less than all of the Securities are to be redeemed at any time, selection of such Securities for redemption will be made by The Depository Trust Company ("DTC") during any period the Securities are issued in the form of a global security registered in the name of DTC or a nominee thereof; *provided that* during any period the Securities are issued in certificated form, the selection of such Securities for redemption will be made by the Trustee by lot or by such other method as the Trustee in its sole discretion shall deem fair and appropriate (or, in the case of Securities issued in global form, by such method as the depositary may require) and which may provide for the selection for redemption of portions of the principal of the Securities. A partial redemption shall not reduce the portion of the principal amount of a Security not redeemed to a principal amount of less than $2,000. Notice of redemption shall be given by first-class mail, postage prepaid, mailed not less than 30 nor more than 60 days before the Redemption Date, to each Holder of Securities to be redeemed, at its address as shown in the Security Register. If the Securities are to be redeemed in part only, the notice of redemption that relates to such Securities shall state the portion of the principal amount thereof to be redeemed. A new Security in a principal amount equal to the unredeemed portion thereof will be issued in the name of the Holder thereof upon surrender for cancellation of the original Security. On and after the Redemption Date, interest will cease to accrue on Securities or portions thereof called for redemption unless the Company defaults in the payment of the Redemption Price.

Sinking Fund . This Security does not have the benefit of any sinking fund obligations.

Modification and Waivers; Obligations of the Company Absolute . The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Securities. Certain limited amendments may be effected under the Indenture at any time by the Company and the Trustee without the consent of any Holders of the Securities. Certain other amendments affecting the Securities may only be effected under the Indenture with the consent of the Holders of not less than a majority in aggregate principal amount of the Securities at the time Outstanding. The Indenture also contains provisions permitting the Holders of not less than a majority in principal amount of the Securities at the time Outstanding, on behalf of the Holders of all Outstanding Securities, to waive compliance by the Company with certain provisions of the Indenture affecting the Securities. Furthermore, provisions in the Indenture permit the Holders of not less than a majority in principal amount of the Outstanding Securities to waive on behalf of all of the Holders of all Outstanding Securities certain past defaults under the Indenture in respect of the Securities and their consequences. Any such consent or waiver by or on behalf of the Holder of this Security shall be conclusive and binding upon such Holder and upon all future Holders of this Security and of any Security issued upon the registration of transfer hereof or in exchange herefor or in lieu hereof whether or not notation of such consent or waiver is made upon this Security.

No reference herein to the Indenture and no provision of this Security or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of (and premium, if any) and interest on this Security at the times, place and rate, and in the coin or currency, herein prescribed.

Defeasance and Covenant Defeasance . The Indenture contains provisions for defeasance at any time of (a) the entire indebtedness of the Company represented by this Security and (b) certain restrictive covenants and the related Defaults and Events of Default, upon compliance by the Company with certain conditions set forth therein, which provisions apply to this Security.

Authorized Denominations . The Securities are issuable only in registered form, without coupons, in minimum denominations of $2,000 and any integral multiple of $1,000 in excess thereof.

Registration of Transfer or Exchange . As provided in the Indenture and subject to certain limitations therein set forth, the transfer of this Security is registrable on the Security Register of the Company, upon surrender of this Security for registration of transfer at the office or agency of the Company, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar duly executed by, the Holder hereof or his attorney duly authorized in writing, and thereupon one or more new Securities, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees. At the date of the original issuance of this Security such office or agency of the Company is maintained by U.S. Bank National Association, 1349 West Peachtree Street, Suite 1050, Atlanta, Georgia.

As provided in the Indenture and subject to certain limitations therein set forth, the Securities are exchangeable for a like aggregate principal amount of Securities of a different authorized denomination, as requested by the Holder surrendering the same.

No service charge shall be made for any registration of transfer or exchange or redemption of Securities, but the Company may require payment of a sum sufficient to pay all documentary, stamp or similar issue or transfer taxes or other governmental charges payable in connection with any registration of transfer or exchange.

Prior to the time of due presentment of this Security for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Security is registered as the owner hereof for all purposes, whether or not this Security be overdue, and neither the Company, the Trustee nor any agent shall be affected by notice to the contrary.

Defined Terms . All capitalized terms used in this Security which are defined in the Indenture shall have the meanings assigned to them in the Indenture.

Governing Laws . This Security and the Indenture shall be governed by and construed in accordance with the laws of the State of New York, without regard to conflicts of laws principles that would apply any other law.

IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed.

ATMOS ENERGY CORPORATION

By:____________________________
Name: Bret J. Eckert
Title: Senior Vice President and
Chief Financial Officer

Attest:

By:____________________________
Name: Louis P. Gregory
Title: Senior Vice President,
General Counsel and
Corporate Secretary

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This is one of the Securities of the series designated therein referred to in the within-mentioned Indenture.

Dated: U.S. Bank National Association, as Trustee

By:________________________________
Authorized Officer

ASSIGNMENT FORM

To assign this Security, fill in the form below:
(I) or (we) assign and transfer this Security to

(Insert assignee's social security or tax I.D. no.)

(Print or type assignee's name, address and zip code)

and irrevocably appoint ______________________________ agent to transfer this Security on the books of the Company. The agent may substitute another to act for him.

Date: ____________ Signature:

(sign exactly as name appears on the other side of this Security)

Signature guaranteed by: ______________________________

Exhibit 5.1

[LETTERHEAD OF GIBSON, DUNN & CRUTCHER LLP]

Client: 03896-00045

January 11, 2013

Atmos Energy Corporation
1800 Three Lincoln Centre
5430 LBJ Freeway
Dallas, Texas 75240

Re: Atmos Energy Corporation Registration Statement on Form S-3 (File No. 333-165818)

Ladies and Gentlemen:

We have acted as counsel to Atmos Energy Corporation (the " Company ") in connection with the preparation and filing with the Securities and Exchange Commission (the " Commission ") of a Registration Statement on Form S-3, file no. 333-165818 (the " Registration Statement "), under the Securities Act of 1933, as amended (the " Securities Act "), the prospectus included therein, the prospectus supplement, dated January 8, 2013, filed with the Commission on January 9, 2013 pursuant to Rule 424(b) of the Securities Act (the " Prospectus Supplement "), and the offering by the Company pursuant thereto of $500,000,000 aggregate principal amount of the Company's 4.15% Senior Notes due 2043 (the " Notes ").

The Notes will be issued pursuant to the Indenture dated as of March 26, 2009 (the " Base Indenture "), between the Company and U.S. Bank National Association, as trustee (the " Trustee "), and an Officers' Certificate (the " Section 301 Officers' Certificate ") to be delivered to the Trustee pursuant to Section 301 of the Base Indenture (the Base Indenture, as modified by the Section 301 Officers' Certificate in respect of the Notes, is referred to herein as the " Indenture "). In connection with the issuance of the Notes, the Company has entered into an Underwriting Agreement dated as of January 8, 2013 (the " Underwriting Agreement ") with the representatives of the underwriters named therein (the " Underwriters "). The Indenture, the Underwriting Agreement and the Notes are referred to collectively as the " Note Documents ."

In arriving at the opinions expressed below, we have examined originals, or copies certified or otherwise identified to our satisfaction as being true and complete copies of the originals, of the Base Indenture, the form of Section 301 Officers' Certificate, the form of Notes, the Underwriting Agreement and such other documents, corporate records, certificates of officers of the Company and of public officials and other instruments as we have deemed necessary or advisable to enable us to render these opinions. In our examination, we have assumed, without independent investigation, the genuineness of all signatures, the legal capacity and competency of all natural persons, the authenticity of all documents submitted to us as originals and the conformity to original documents of all documents submitted to us as copies. As to any facts material to these opinions, we have relied to the extent we deemed appropriate and without independent investigation upon statements and representations of officers and other representatives of the Company and others.

Atmos Energy Corporation
January 11, 2013
Page 2

Based upon the foregoing, and subject to the assumptions, exceptions, qualifications and limitations set forth herein, we are of the opinion that the Notes, when executed and authenticated in accordance with the provisions of the Indenture and delivered to and paid for by the Underwriters in accordance with the terms of the Underwriting Agreement, will be legal, valid and binding obligations of the Company.

The opinions expressed above are subject to the following additional exceptions, qualifications, limitations and assumptions:

A. We render no opinion herein as to matters involving the laws of any jurisdiction other than the State of New York and to the extent relevant for our opinions herein, the Texas Business Organizations Code. This opinion is limited to the effect of the current state of the laws of the State of New York and the Texas Business Organizations Code and the facts as they currently exist. We express no opinion regarding any federal or state laws or regulations related to the regulation of utilities. We assume no obligation to revise or supplement this opinion in the event of future changes in such laws or the interpretations thereof or such facts.

B. We note that the Company is incorporated in the State of Texas and in the Commonwealth of Virginia and we have assumed, without independent investigation, that the Company is a validly existing corporation in good standing under the laws of the Commonwealth of Virginia and that under the laws of the Commonwealth of Virginia: (i) the Company has all requisite power to execute, deliver and perform its obligations under the Note Documents, (ii) the execution and delivery of such documents by the Company and the performance of its obligations thereunder have been duly authorized by all necessary corporate action and do not violate any law, regulation, order, judgment or decree applicable to the Company and (iii) that such documents will be duly executed and delivered by the Company. We understand that you are receiving an opinion of Virginia counsel as to matters relating to Virginia law.

C. The opinions above are subject to (i) the effect of any bankruptcy, insolvency, reorganization, moratorium, arrangement or similar laws affecting the rights and remedies of creditors' generally, including without limitation the effect of statutory or other laws regarding fraudulent transfers or preferential transfers and (ii) general principles of equity, including without limitation concepts of materiality, reasonableness, good faith and fair dealing and the possible unavailability of specific performance, injunctive relief or other equitable remedies regardless of whether enforceability is considered in a proceeding in equity or at law.

D. We express no opinion regarding the effectiveness of (i) any waiver of stay, extension or usury laws or of unknown future rights or (ii) provisions relating to indemnification, exculpation or contribution, to the extent such provisions may be held unenforceable as contrary to public policy or federal or state securities laws.

We consent to the filing of this opinion as an exhibit to the Registration Statement, and we further consent to the use of our name under the caption "Legal Matters" in the Registration Statement and the Prospectus Supplement. In giving these consents, we do not thereby admit that we are within the category of persons whose consent is required under Section 7 of the Securities Act or the rules and regulations of the Commission promulgated thereunder.

Very truly yours,

/s/ Gibson, Dunn & Crutcher LLP

Exhibit 5.2

HUNTON & WILLIAMS

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January 11, 2013

Atmos Energy Corporation
1800 Three Lincoln Centre
Dallas, Texas 75240

Atmos Energy Corporation
Public Offering of 4.15% Senior Notes due 2043

Ladies and Gentlemen:

We have acted as special Virginia counsel for Atmos Energy Corporation, a Texas and Virginia corporation (the "Company"), for the purpose of providing this opinion in connection with the Company's issuance and sale of $500 million of the Company's 4.15% Senior Notes due 2043 (the "Notes").

The Notes are being issued pursuant to an indenture, dated as of March 26, 2009 (the "Indenture"), between the Company and U.S. Bank National Association, as trustee (the "Trustee"), and an officers' certificate to be delivered to the Trustee pursuant to Section 301 of the Indenture (the "Section 301 Officers' Certificate"). The Notes are being offered and sold as described in the prospectus, dated March 31, 2010, contained in the Registration Statement on Form S-3 (Registration No. 333-165818) (the "Registration Statement") filed by the Company with the Securities and Exchange Commission (the "Commission") on March 31, 2010 pursuant to the Securities Act of 1933, as amended (the "Act"), and the prospectus supplement thereto, dated January 8, 2013 (collectively, the "Prospectus").

This opinion is being furnished in accordance with the requirements of Item 16 of Form S-3 and Item 601(b)(5)(i) of Regulation S-K promulgated under the Act.

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In connection with this opinion, we have examined originals or copies, certified or otherwise identified to our satisfaction, of such corporate records of the Company, certificates of corporate officers of the Company and public officials and such other documents as we have deemed necessary for the purposes of rendering this opinion, including, among other things, (i) the Virginia Restated Articles of Incorporation and the Amended and Restated Bylaws of the Company, each as amended through the date hereof, (ii) a certificate issued by the State Corporation Commission of the Commonwealth of Virginia on January 11, 2013, to the effect that the Company is existing under the laws of the Commonwealth of Virginia and in good standing, (iii) resolutions of the Board of Directors of the Company, adopted at a meeting held on November 6, 2012, (iv) the Registration Statement, (v) the Prospectus, (vi) the Indenture, (vii) the Section 301 Officers' Certificate, (viii) the Notes and (ix) the Underwriting Agreement, dated January 8, 2013 (the "Underwriting Agreement"), among the Company and J.P. Morgan Securities LLC, Mitsubishi UFJ Securities (USA), Inc. and U.S. Bancorp Investments, Inc. as representatives of the several Underwriters listed on Schedule I to the Underwriting Agreement.

For purposes of the opinions expressed below, we have assumed (i) the authenticity of all documents submitted to us as originals, (ii) the conformity to the originals of all documents submitted to us as certified, photostatic or electronic copies and the authenticity of the originals thereof, (iii) the legal capacity of natural persons, (iv) the genuineness of all signatures not witnessed by us and (v) the due authorization, execution and delivery of all documents by all parties and the validity, binding effect and enforceability thereof on such parties (other than the authorization, execution and delivery of documents by the Company).

As to factual matters, we have relied upon, and assumed the accuracy of, representations included in the documents submitted to us, upon certificates of officers of the Company and upon certificates of public officials. Except as otherwise expressly indicated, we have not undertaken any independent investigation of factual matters.

We do not purport to express an opinion on any laws other than those of the Commonwealth of Virginia.

Based upon the foregoing and such other information and documents as we have considered necessary for the purposes hereof, and subject to the assumptions, qualifications and limitations stated herein, we are of the opinion that:

HUNTON & WILLIAMS

Atmos Energy Corporation
January 11, 2013
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1. The Company is validly existing as a corporation in good standing under the laws of the Commonwealth of Virginia.

2. The Company has all requisite corporate power to execute, deliver and perform its obligations under the Indenture, the Section 301 Officers' Certificate and the Notes, and the execution and delivery of such documents by the Company and the performance of its obligations thereunder have been duly authorized by all necessary corporate action and do not violate any law or regulation of the Commonwealth of Virginia or any order, judgment or decree of any court, regulatory body, administrative agency or governmental body of the Commonwealth of Virginia applicable to the Company.

We hereby consent to (a) the filing of this opinion with the Commission as an exhibit to the Company's Current Report on Form 8-K filed the date hereof, (b) the incorporation by reference of this opinion into the registration statement and (c) the reference to our firm under the heading "Legal Matters" in the Prospectus. In giving this consent, we do not admit that we are within the category of persons whose consent is required by Section 7 of the Act and the rules and regulations of the Commission promulgated thereunder.

This opinion is rendered as of the date hereof, and we disclaim any obligation to advise you of facts, circumstances, events or developments that hereafter may be brought to our attention and that may alter, affect or modify the opinion expressed herein. Our opinion is expressly limited to the matters set forth above and we render no opinion, whether by implication or otherwise, as to any other matters relating to the Company or the Notes.

Very truly yours,

/s/ Hunton & Williams LLP