ATMOS ENERGY CORP
Form 10-K
November 13, 2012
Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

þ **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 þ 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 þ

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 þ 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 þ 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. þ

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 þ	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 þ

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.

Table of Contents

TABLE OF CONTENTS

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
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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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 (In thousands)	Effective Date
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.

Table of Contents

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 (In thousands)	Increase in Annual Operating Income (In thousands)	Effective Date
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.

Table of Contents

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 (In thousands)	Effective Date
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.

Table of Contents

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 (In thousands)	Effective Date
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.

16

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.

Table of Contents

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.

Table of Contents

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 nonregulated segment owned 105 miles of gas transmission and gathering lines.

Table of Contents

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.

23

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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 (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (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.

Table of Contents

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 , strat 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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)
	$ 0.43	$ 0.47	$ 0.47	$ (0.04)	$

Consolidated natural gas distribution average transportation revenue per Mcf										
Consolidated natural gas distribution average cost of gas per Mcf sold	$	4.64	$	5.30	$	5.77	$	(0.66)	$	(0.47)

35

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

- 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.

Table of Contents

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.

Table of Contents

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 (In thousands, unless otherwise noted)				
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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)

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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

Table of Contents

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2012	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.

Table of Contents

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.

Table of Contents

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, 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.

Table of Contents

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 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
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 allow-

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ance 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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

62

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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

73

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (In thousands)	Total
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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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)

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 (In thousands)	Total
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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[2]	Significant Other Unobservable Inputs (Level 3) (In thousands)	Netting and Cash Collateral[4]	September 30, 2011
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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Table of Contents

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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				