FORM 10-K

Annual report pursuant to section 13 and 15(d)

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ATMOS ENERGY CORP	Mailing Address	Business Address
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended September 30, 2012

OR

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

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.45) is not contained herein, and will not be contained, to the best of registrant’ s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant’ s most recently completed second fiscal quarter, March 31, 2012, was $2,764,486,845.

As of November 6, 2012, the registrant had 90,240,464 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’ s Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 13, 2013, are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
APS	Atmos Pipeline and Storage, LLC
ATO	Trading symbol for Atmos Energy Corporation common stock on the New York Stock Exchange
Bcf	Billion cubic feet
COSO	Committee of Sponsoring Organizations of the Treadway Commission
ERISA	Employee Retirement Income Security Act of 1974
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
KPSC	Kentucky Public Service Commission
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
Mid-Tex Cities	Represents 440 of the 441 incorporated cities, or approximately 80 percent of the Mid-Tex Division’ s customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.
MMcf	Million cubic feet
Moody’ s	Moody’ s Investor Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
PAP	Pension Account Plan
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor’ s Corporation
SEC	United States Securities and Exchange Commission
SRF	Stable Rate Filing
WNA	Weather Normalization Adjustment

PART I

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

ITEM 1. *Business.*

Overview and Strategy

Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. We deliver natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in nine states located primarily in the South, which makes us one of the country' s largest natural-gas-only distributors based on number of customers. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

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

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

Our overall strategy is to:

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

We have delivered excellent shareholder value by growing our earnings and increasing our dividends for over 25 consecutive years. Through fiscal 2005, we achieved this record of growth through acquisitions while efficiently managing our operating and maintenance expenses and leveraging our technology to achieve more efficient operations. Since that time, we have achieved growth by implementing rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns. In addition, we have developed various commercial opportunities within our regulated transmission and storage operations.

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

Operating Segments

We operate the Company through the following three segments:

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

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

Our natural gas distribution segment represents approximately 65 percent of our consolidated net income. This segment is comprised of the following six regulated divisions, presented in order of total rate base, covering service areas in nine states:

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

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

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia and Virginia. See Note 6 in the consolidated financial statements for a description of the completed sale of our Missouri, Illinois and Iowa service areas and the anticipated sale of our Georgia distribution operations. In addition, we transport natural gas for others through our distribution system.

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

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

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

Finally, regulatory authorities have approved weather normalization adjustments (WNA) for approximately 97 percent of residential and commercial margins in our service areas as a part of our rates. WNA minimizes the effect of weather that is above or below normal by allowing us to increase customers' bills to offset the effect of lower gas usage when weather is warmer than normal and decrease customers' bills to offset the effect of higher gas usage when weather is colder than normal.

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

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

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

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

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest reasonable cost. Major suppliers during fiscal 2012 were Anadarko Energy Services, BP Energy Company, ConocoPhillips, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., Iberdrola Renewables, Inc., National Fuel Marketing Company, LLC, Sequent Energy Management, L.P., Texla Energy Management, Inc. and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary.

The combination of base load, peaking and spot purchase agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments. We estimate our peak-day availability of natural gas supply to be approximately 4.4 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2012 was on February 11, 2012, when sales to customers reached approximately 3.0 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 43 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have "pipeline no-notice" storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered primarily by our Atmos Pipeline − Texas Division.

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

Below, we briefly describe our six natural gas distribution divisions. We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2012, we held 1,006 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire. Additional information concerning our natural gas distribution divisions is presented under the caption "Operating Statistics".

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

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

Atmos Energy Kentucky/Mid-States Division. Our Kentucky/Mid-States Division currently operates in more than 230 communities across Georgia, Kentucky, Tennessee and Virginia. The service areas in these states are primarily rural; however, this division serves Franklin, Tennessee and other suburban areas of Nashville. We update our rates in this division through periodic formal rate filings made with each state' s public service commission.

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

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

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. In fiscal 2008 and 2009, we reached an agreement with the West Texas service areas and the Amarillo and Lubbock service areas that allowed us to update rates for customers in these cities using an annual rate review mechanism (RRM) through fiscal 2011, when the RRM was active. We filed a formal rate case for the West Texas Division in fiscal 2012, which was approved on October 2, 2012. We expect to negotiate a new rate review mechanism process in fiscal 2013.

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

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

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

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

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

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

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

(3) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $36.1 million included in the October 2011 Pipeline Replacement Program (PRP) surcharge. A total of $36.1 million of the Georgia

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

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

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

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

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

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

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

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment represents approximately 30 percent of our consolidated net income and consists of the regulated pipeline and storage operations of our Atmos Pipeline − Texas Division. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands. Gross profit earned from our Mid-Tex Division and through certain other transportation and storage services is subject to traditional ratemaking governed by the RRC. Rates are updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. Atmos Pipeline− Texas' existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates with minimal regulation.

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

Nonregulated Segment Overview

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

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

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

Ratemaking Activity

Overview

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

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has:

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

Although substantial progress has been made in recent years by improving rate design across Atmos Energy' s operating areas, we will continue to seek improvements in rate design to address cost variations that are related to pass-through energy costs beyond our control. Further, potential changes in federal energy policy and adverse economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Substantially all of our regulated revenues in the fiscal years ended September 30, 2012, 2011 and 2010 were derived from sales at rates set by or subject to approval by local or state authorities. Net operating income increases resulting from ratemaking activity totaling $30.7 million, $72.4 million and $56.8 million, became effective in fiscal 2012, 2011 and 2010, as summarized below:

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

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

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

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

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

(3) Georgia Rate Adjustment Mechanism

(4) A hearing was conducted in September 2012. A final order is expected in December 2012.

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

Our recent ratemaking activity is discussed in greater detail below.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company' s costs as well as a fair rate of return to our shareholders and ensure that we continue to safely deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

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

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

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Infrastructure Programs

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

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

Kentucky/Mid-States – Georgia[2]	09/ 2008	6,327	909	10/01/ 2009
Total 2010 Infrastructure Programs		$ 148,441	$ 18,989	

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

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

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

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

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

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. As discussed above in "Natural Gas Distribution Segment Overview," we currently have annual rate filing mechanisms in our Louisiana, Mississippi and Georgia divisions and in a portion of our Texas divisions. These mechanisms are referred to as Dallas annual rate review (DARR) in our Mid-Tex Division, stable rate filings in the Mississippi Division, the rate stabilization clause in the Louisiana Division, the Georgia Rate Adjustment Mechanism (GRAM) in the Georgia Division and previously as rate review mechanisms (RRM) in our Texas divisions. The following table summarizes filings made under our various annual rate filing mechanisms:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income (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.

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.

ITEM 1A. ***Risk Factors.***

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

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

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

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

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

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

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

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

The costs of providing pension and postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of health care benefits for our employees. Further, the costs to the Company of providing such benefits and related funding requirements are subject to the continued and timely recovery of such costs through our rates.

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

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

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

Our risk management operations are subject to market risks beyond our control, including market liquidity, commodity price volatility caused by market supply and demand dynamics and counterparty creditworthiness. Although we maintain a risk management policy, we may not be able to completely offset the price risk associated with volatile gas prices, particularly in our nonregulated business segment, which could lead to volatility in our earnings.

Physical trading in our nonregulated business segment also introduces price risk on any net open positions at the end of each trading day, as well as volatility resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. The determination of our net open position as of the end of any particular trading day requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of such day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Although we manage our business to maintain no open positions, there are times when limited net open positions related to our physical storage may occur on a short-term basis. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner before the open positions can be closed.

Further, the timing of the recognition for financial accounting purposes of gains or losses resulting from changes in the fair value of derivative financial instruments designated as hedges usually does not match the timing of the economic profits or losses on the item being hedged. This volatility may occur with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated. Also, if the local physical markets in which we trade do not move consistently with the NYMEX futures market upon which most of our commodity derivative financial instruments are valued, we could experience increased volatility in the financial results of our nonregulated segment.

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

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

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

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

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

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

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

FERC has regulatory authority over some of our operations, including sales of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. Under legislation passed by Congress in 2005, FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC’ s other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. Although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

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

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations.

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

There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The adoption of this type of legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

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

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

Adverse weather conditions could affect our operations or financial results.

We have weather-normalized rates for over 95 percent of our residential and commercial meters, which substantially mitigates the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather-normalized rates could have an adverse effect on our operations and financial results. In addition, our natural gas distribution and regulated transmission and storage operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Sustained cold weather could adversely affect our nonregulated operations as we may be required to purchase gas at spot rates in a rising market to obtain sufficient volumes to fulfill some customer contracts. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our natural gas distribution and regulated transmission and storage operations.

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

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

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

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

We must continually build additional capacity in our natural gas distribution system to enable us to serve any growth in the number of our customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. In addition, although we should ultimately recover the cost of the expenditures through rates, we must make significant capital expenditures to comply with the recent rule issued by the RRC' s Division of Public Safety that requires natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. Our cash flows from operations generally are sufficient to supply funding for all our capital expenditures, including the financing of the costs of new construction along with capital expenditures necessary to maintain our existing natural gas system. Due to the timing of these cash flows and capital expenditures, we often must fund at least a portion of these costs through borrowing funds from third party lenders, the cost and availability of which is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Our operations are subject to increased competition.

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

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services.

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

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

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

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

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

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

ITEM 1B. ***Unresolved Staff Comments.***

Not applicable.

ITEM 2. ***Properties.***

Distribution, transmission and related assets

At September 30, 2012, our natural gas distribution segment owned an aggregate of 68,072 miles of underground distribution and transmission mains throughout our gas distribution systems. These mains are located on easements or rights-of-way which generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. Our regulated transmission and storage segment owned 5,698 miles of gas transmission and gathering lines and our nonregulated segment owned 105 miles of gas transmission and gathering lines.

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Storage Assets

We own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities at September 30, 2012:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf)(1)	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Natural Gas Distribution Segment				
Kentucky	4,442,696	6,322,283	10,764,979	105,100
Kansas	3,239,000	2,300,000	5,539,000	45,000
Mississippi	2,211,894	2,442,917	4,654,811	48,000
Georgia	490,000	10,000	500,000	30,000
Total	10,383,590	11,075,200	21,458,790	228,100
Regulated Transmission and Storage Segment − Texas	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated Segment				
Kentucky	3,492,900	3,295,000	6,787,900	71,000
Louisiana	438,583	300,973	739,556	56,000
Total	3,931,483	3,595,973	7,527,456	127,000
Total	60,458,299	30,549,198	91,007,497	1,590,100

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

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity at September 30, 2012:

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

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

Offices

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

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

See Note 13 to the consolidated financial statements.

PART II

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

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The high and low sale prices and dividends paid per share of our common stock for fiscal 2012 and 2011 are listed below. The high and low prices listed are the closing NYSE quotes, as reported on the NYSE composite tape, for shares of our common stock:

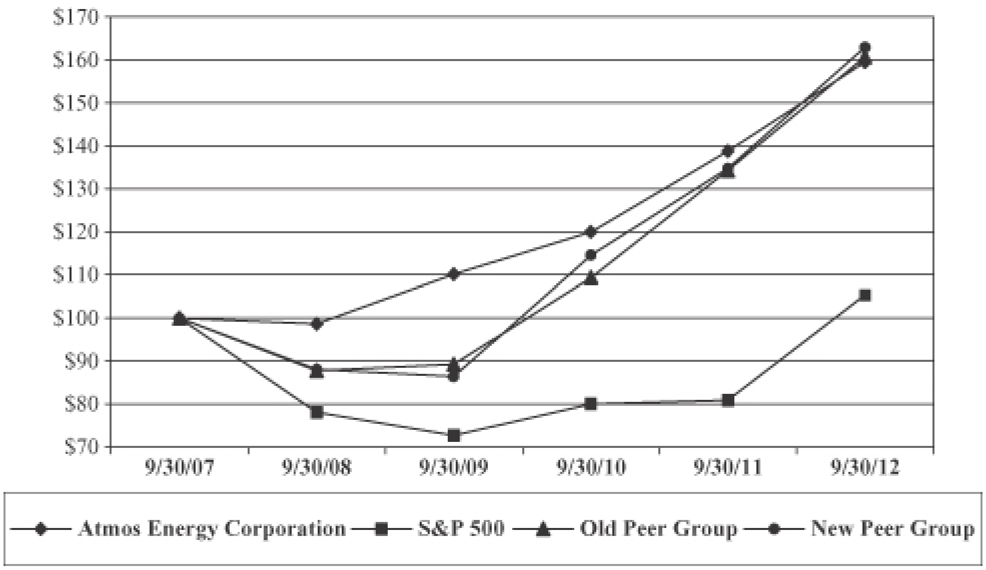
	Fiscal 2012			Fiscal 2011		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$35.40	$30.97	$ .345	$31.72	$29.10	$ .340
March 31	33.15	30.60	.345	34.98	31.51	.340
June 30	35.07	30.91	.345	34.94	31.34	.340
September 30	36.94	34.94	.345	34.32	28.87	.340
			$ 1.38			$ 1.36

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2012 was 17,883. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2012 that were not registered under the Securities Act of 1933, as amended.

Performance Graph

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the Standard and Poor' s 500 Stock Index and the cumulative total return of two different customized peer company groups, the New Comparison Company Index and the Old Comparison Company Index. The New Comparison Company Index includes Questar and excludes EQT Corporation because the Board of Directors determined that Questar better fits the profile of the companies in the peer group, which is comprised of natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2007 in our common stock, the S&P 500 Index and in the common stock of the companies in the New and Old Comparison Company Indexes, as well as a reinvestment of dividends paid on such investments throughout the period.

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



	Cumulative Total Return					
	9/30/07	9/30/08	9/30/09	9/30/10	9/30/11	9/30/12
Atmos Energy Corporation	100.00	98.61	110.13	119.94	138.80	159.56
S&P 500	100.00	78.02	72.63	80.01	80.93	105.37
Old Peer Group	100.00	87.71	89.32	109.42	134.24	160.67
New Peer Group	100.00	88.10	86.44	114.56	134.80	162.92

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

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2012.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	10,094	$ 24.95	1,949,088
Total equity compensation plans approved by security holders	10,094	24.95	1,949,088
Equity compensation plans not approved by security holders	–	–	–
Total	10,094	$ 24.95	1,949,088

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

ITEM 6. *Selected Financial Data.*

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

	Fiscal Year Ended September 30				
	2012(1)	2011(1)	2010	2009(1)	2008
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$3,438,483	$4,286,435	$4,661,060	$4,793,248	$7,039,342
Gross profit	$1,323,739	$1,300,820	$1,314,136	$1,297,682	$1,275,077
Income from continuing operations	$192,196	$189,588	$189,851	$175,026	$166,696
Net income	$216,717	$207,601	$205,839	$190,978	$180,331
Diluted income per share from continuing operations	$2.10	$2.07	$2.03	$1.90	$1.84
Diluted net income per share	$2.37	$2.27	$2.20	$2.07	$1.99
Cash dividends declared per share	$1.38	$1.36	$1.34	$1.32	$1.30
Financial Condition					
Net property, plant and equipment(2)	$5,475,604	$5,147,918	$4,793,075	$4,439,103	$4,136,859
Total assets	$7,495,675	$7,282,871	$6,763,791	$6,367,083	$6,386,699
Capitalization:					
Shareholders' equity	$2,359,243	$2,255,421	$2,178,348	$2,176,761	$2,052,492
Long-term debt (excluding current maturities)	1,956,305	2,206,117	1,809,551	2,169,400	2,119,792
Total capitalization	$4,315,548	$4,461,538	$3,987,899	$4,346,161	$4,172,284

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

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

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

INTRODUCTION

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

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

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

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

CRITICAL ACCOUNTING POLICIES

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from estimates.

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

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

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

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

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

We record all of our financial instruments on the balance sheet at fair value as required by accounting principles generally accepted in the United States, with changes in fair value ultimately recorded in the income statement. Market value changes result in a change in the fair value of these financial instruments. The recognition of the changes in fair value of these financial instruments are recorded in the income statement is contingent upon whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment.

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

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

Additionally, we have elected to treat fixed-price forward contracts used in our nonregulated segment to deliver gas as normal purchases and normal sales. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on open financial instruments are recorded as a component of accumulated other comprehensive income (loss) and are recognized as a component of revenue when the hedged volumes are sold.

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

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

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

Fair Value Measurements − We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed.

We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

The fair value of our financial instruments is subject to potentially significant volatility based numerous considerations including, but not limited to changes in commodity prices, interest rates, maturity and settlement of these financial instruments, and our creditworthiness as well as the creditworthiness of our counterparties. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts.

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

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

Pension and other postretirement plans − Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

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

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

Actual changes in the fair market value of plan assets and differences between the actual and expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately $2.3 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $0.8 million.

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

RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 56 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

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

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

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

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

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

Consolidated Results

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

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

Regulated operations contributed 98 percent, 104 percent and 81 percent to our consolidated net income for fiscal years 2012, 2011 and 2010. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands)		
Natural gas distribution segment	$148,369	$162,718	$125,949
Regulated transmission and storage segment	63,059	52,415	41,486
Nonregulated segment	5,289	(7,532)	38,404
Net income	$216,717	$207,601	$205,839

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

	For the Fiscal Year Ended September 30		
	2012	2011	2010
	(In thousands, except per share data)		
Regulated operations	$211,428	$215,133	$167,435
Nonregulated operations	5,289	(7,532)	38,404
Consolidated net income	$216,717	$207,601	$205,839
Diluted EPS from regulated operations	$2.31	$2.35	$1.79
Diluted EPS from nonregulated operations	0.06	(0.08)	0.41
Consolidated diluted EPS	$2.37	$2.27	$2.20

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

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

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

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

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

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

Natural Gas Distribution Segment

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

Our ability to earn our authorized rates is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions. The “Ratemaking Activity” section of this Form 10-K describes our current rate strategy, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore the cost of gas typically does not have an impact on our gross profit as increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

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

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

Review of Financial and Operating Results

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

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

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

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

These increases were partially offset by the following:

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

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

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

These increases were partially offset by the following:

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

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

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

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

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

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

These increases were partially offset by:

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

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

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

These decreases were partially offset by:

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

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

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

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

Regulated Transmission and Storage Segment

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

Our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex service area. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline − Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our Mid-Tex Division.

Finally, as a regulated pipeline, the operations of the Atmos Pipeline − Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

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

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

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

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

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

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

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

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

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

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

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

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

These increases were partially offset by the following:

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

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

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

These increases were partially offset by the following:

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

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

Nonregulated Segment

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

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

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

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

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

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

Natural gas prices can influence:

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

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

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Price volatility also influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads.
- Increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

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

Review of Financial and Operating Results

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

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

Cash Flows

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

Cash flows from operating, investing and financing activities for the years ended September 30, 2012, 2011 and 2010 are presented below.

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

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and purchased gas cost recoveries. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

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

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

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

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

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide safe and reliable natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our current rate strategy, we are focusing our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution divisions and our Atmos Pipeline − Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

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

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

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

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

Cash flows from financing activities

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

2012

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

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

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

2011

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

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

2010

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

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

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

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

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

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

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

Credit Facilities

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

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

Shelf Registration

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

Credit Ratings

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

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

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

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

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

Debt Covenants

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

Capitalization

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

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

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

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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.

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With the exception of our Mid-Tex Division, our natural gas distribution segment maintains supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of individual contracts. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of natural gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under the terms of these contracts as of September 30, 2012 are reflected in the table above.

Risk Management Activities

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

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

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

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

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

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

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

	Fair Value of Contracts at September 30, 2012				
	Maturity in years				
Source of Fair Value	Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(78,543)	$2,283	$−	$ −	$(76,260)
Prices based on models and other valuation methods	−	−	−	−	−

Total Fair Value	$(78,543)	$2,283	$−	$ −	$(76,260)

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

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

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

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

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

Employee Benefits Programs

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

Medical and Dental Insurance

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

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

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

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2012, our total net periodic pension and other benefits costs was $69.2 million, compared with $56.6 million and $50.8 million for the fiscal years ended September 30, 2011 and 2010. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates. A portion of these costs is capitalized into our gas distribution rate base, and the remaining costs are recorded as a component of operation and maintenance expense.

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

The increase in total net periodic pension and other benefits costs during fiscal 2011 compared with fiscal 2010 primarily reflects the decrease in our discount rate at September 30, 2010, the measurement date for our fiscal 2011 pension and postretirement costs. The discount rate used to compute the present value of a plan' s liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. At our September 30, 2010 measurement date, the interest rates were significantly higher than the interest rates at September 30, 2009, the measurement date used to determine our fiscal 2009 net periodic cost. Our expected return on our pension plan assets remained constant at 8.25 percent.

Pension and Postretirement Plan Funding

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

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

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

We contributed $22.1 million, $11.3 million and $11.8 million to our postretirement benefits plans for the fiscal years ended September 30, 2012, 2011 and 2010. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

Outlook for Fiscal 2013 and Beyond

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

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

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

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

RECENT ACCOUNTING DEVELOPMENTS

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

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

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

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

Commodity Price Risk

Natural gas distribution segment

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

Nonregulated segment

Our nonregulated segment is also exposed to risks associated with changes in the market price of natural gas. For our nonregulated segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a $0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH' s net open position (including existing storage and related financial contracts) at September 30, 2012 of 0.4 Bcf, a $0.50 change in the forward NYMEX price would have had a $0.2 million impact on our consolidated net income.

Changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at September 30, 2012 and assuming our hedges would still qualify as highly effective, a $0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately $5.8 million.

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

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately $2.5 million during 2012.

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

Index to financial statements and financial statement schedule:

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2012 and 2011, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2012. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2012, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 12, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2012

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ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

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

See accompanying notes to consolidated financial statements.

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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.

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ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock Number of Shares	Common stock Stated Value	Additional Paid-in Capital	Accumulated Other 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.

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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-

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.

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

Currently, authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. During the fiscal years ended September 30, 2012, 2011 and 2010, we recognized $0.5 million, $0.5 million and $0.4 million in amortization expense related to these costs.

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

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

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

Operating revenues for our nonregulated segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our nonregulated activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2012, 2011 and 2010, we included unrealized gains (losses) on open contracts of $(8.0) million, $(10.4) million and $(7.8) million as a component of nonregulated revenues.

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

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

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

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

Regulated property, plant and equipment − Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $2.6 million, $1.7 million and $3.9 million was capitalized in 2012, 2011 and 2010.

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

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.6 percent, 3.6 percent and 3.5 percent for the fiscal years ended September 30, 2012, 2011 and 2010.

Nonregulated property, plant and equipment − Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 50 years.

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

As of September 30, 2012 and 2011, we recorded asset retirement obligations of $10.5 million and $14.0 million. Additionally, we recorded $4.2 million and $5.4 million of asset retirement costs as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

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

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 instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with accounting principles generally accepted in the United States. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

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

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

Gains and losses from hedge ineffectiveness are recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the financial instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity is referred to as timing ineffectiveness. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Our nonregulated segment also utilizes master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. As of September 30, 2012 and 2011, the Company netted $23.7 million and $28.8 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We manage interest rate risk, typically when we plan to issue new long-term debt or to refinance existing long-term debt. Prior to fiscal 2012, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement.

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

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

Fair Value Measurements − We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices), as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed.

We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

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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.

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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.

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

jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 25 percent, or 25.7 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $4.78 per Mcf. We have not designated these financial instruments as hedges.

Nonregulated Commodity Risk Management Activities

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

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

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

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

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

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

Interest Rate Risk Management Activities

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

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

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

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

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

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

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

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

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	Total
			(In thousands)	
September 30, 2012				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$−	$ 19,301	$19,301
Noncurrent commodity contracts	Deferred charges and other assets	−	1,923	1,923
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(85,040)	(23,787)	(108,827)
Noncurrent commodity contracts	Deferred credits and other liabilities	−	(4,999)	(4,999)
Total		(85,040)	(7,562)	(92,602)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets(1)	7,082	98,393	105,475
Noncurrent commodity contracts	Deferred charges and other assets	2,283	60,932	63,215
Liability Financial Instruments				
Current commodity contracts	Other current liabilities(2)	(585)	(99,824)	(100,409)
Noncurrent commodity contracts	Deferred credits and other liabilities	−	(67,062)	(67,062)
Total		8,780	(7,561)	1,219
Total Financial Instruments		$(76,260)	$ (15,123)	$(91,383)

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

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

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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)

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.

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

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

Financial Instruments Not Designated as Hedges

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

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

5. Fair Value Measurements

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

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

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2012 and 2011. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

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

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

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

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

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

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

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.

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

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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

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

Regulated Operations

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

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

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

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2012, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

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

Nonregulated Operations

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

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

At September 30, 2012, there were no borrowings outstanding under this credit facility. However, at September 30, 2012, AEM letters of credit totaling $11.5 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $138.5 million at September 30, 2012.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At September 30, 2012, AEM' s ratio of total liabilities to tangible net worth, as defined, was 0.74 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at September 30, 2012, AEM' s net working capital was $136.2 million and its tangible net worth was $150.8 million.

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

Shelf Registration

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

Debt Covenants

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

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

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

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

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	(464,321)	27.21	(493,957)	29.24
Forfeited	(39,963)	29.83	(56,842)	27.56	(59,202)	26.54
Nonvested at end of year	1,262,582	$ 32.46	1,264,142	$ 29.56	1,293,960	$ 27.28

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2012		2011		2010	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	86,766	$22.16	434,962	$22.46	611,227	$21.88
Granted	–	–	–	–	–	–
Exercised	(76,672)	21.79	(348,196)	22.54	(176,265)	20.44
Forfeited	–	–	–	–	–	–
Expired	–	–	–	–	–	–
Outstanding at end of year(1)	10,094	$24.95	86,766	$22.16	434,962	$22.46
Exercisable at end of year(2)	10,094	$24.95	86,766	$22.16	434,962	$22.46

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

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

Information about outstanding and exercisable options under the LTIP, as of September 30, 2012, is reflected in the following tables:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price
$21.23 to $22.99	2,164	0.4	$21.23
$23.00 to $25.95	7,930	2.1	$25.95
$21.23 to $25.95	10,094	1.7	$24.95

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

As of September 30, 2012, there was no unrecognized compensation cost related to nonvested stock options.

Other Plans

Direct Stock Purchase Plan

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

Outside Directors Stock-For-Fee Plan

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

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

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

Other Discretionary Compensation Plans

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

In addition, we adopted an incentive plan in October 2001 to give the employees in our nonregulated segment an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure is based upon the net earnings of the nonregulated operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

9. Retirement and Post-Retirement Employee Benefit Plans

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets are as follows:

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2012				
Unrecognized transition obligation	$−	$ −	$ 1,709	$1,709
Unrecognized prior service cost	(232)	−	(7,411)	(7,643)
Unrecognized actuarial loss	187,050	43,995	63,402	294,447
	$ 186,818	$ 43,995	$ 57,700	$288,513
September 30, 2011				
Unrecognized transition obligation	$−	$ −	$ 3,220	$3,220
Unrecognized prior service cost	(373)	−	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$ 182,113	$ 30,654	$ 41,899	$254,666

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2012, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

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

The Plan also provides for an additional annual allocation based upon a participant' s age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan credited this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant' s account is credited with interest on the employee' s prior year account balance. A special grandfather benefit also applied through December 31, 2008, for participants who were at least age 50 as of January 1, 1999 and who were participants in one of the prior plans on December 31, 1998. Participants are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan which was enhanced, effective January 1, 2011.

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

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974, including the funding requirements under the Pension

Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

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

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

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

The following table presents asset allocation information for the Master Trust as of September 30, 2012 and 2011.

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a September 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plans were determined as of September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

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

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

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

Supplemental Executive Benefits Plans

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

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

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

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

Estimated Future Benefit Payments

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

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

Postretirement Benefits

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

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

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of ERISA. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute $28.3 million to our postretirement benefits plan during fiscal 2013.

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

We currently invest the assets funding our postretirement benefit plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2012 and 2011.

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

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2011, 2010 and 2009. The assumptions are presented in the following table:

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

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

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

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

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

Estimated Future Benefit Payments

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

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2013	$28,317	$3,696	$ −	$ 32,013
2014	15,174	4,487	−	19,661
2015	17,349	5,251	−	22,600
2016	19,221	6,128	−	25,349
2017	20,520	7,083	−	27,603
2018-2022	107,055	48,114	−	155,169

Defined Contribution Plans

As of September 30, 2012, we maintained three defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan), the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan) and the Atmos Energy Holdings, LLC 401K Profit-Sharing Plan (the AEH 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant’ s contributions, limited to four percent of the participant’ s salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees participate in our defined contribution plan, which was enhanced, effective January 1, 2011. Employees participating in the Pension Account Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into the Retirement Savings Plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

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

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to $10.5 million, $10.2 million, and $9.8 million for fiscal years 2012, 2011 and 2010. The Board

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

The AEH 401K Profit-Sharing Plan covers substantially all AEH employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 75 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. The Company may elect to make safe harbor contributions up to four percent of the employee' s salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEH 401K Profit-Sharing Plan. Participants become fully vested in the discretionary profit-sharing contributions after three years of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. Discretionary contributions to the AEH 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.2 million, $1.3 million and $1.3 million for fiscal years 2012, 2011 and 2010.

10. Details of Selected Consolidated Balance Sheet Captions

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

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2012 and 2011:

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

Other current assets

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

Property, plant and equipment

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

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

Deferred charges and other assets

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

Other current liabilities

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

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

Deferred credits and other liabilities

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

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

11. Earnings Per Share

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

12. Income Taxes

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2012 and 2011 are presented below:

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

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

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

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

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

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We recognized a tax expense of $0.01 million, $0.01 million and $0.5 million related to penalty and interest expenses during the fiscal years ended September 30, 2012, 2011 and 2010.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2007.

13. Commitments and Contingencies

Litigation

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

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

Environmental Matters

Former Manufactured Gas Plant Sites

We are the owner or previous owner of former manufactured gas plant sites in Johnson City, Tennessee and Keokuk, Iowa, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa and the United States Environmental Protection Agency.

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

Purchase Commitments

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

Other Contingencies

In December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission' s posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

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

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

14. Leases

Capital and Operating Leases

We have entered into operating leases for office and warehouse space, vehicles and heavy equipment used in our operations. The remaining lease terms range from one to 21 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $1.3 and $1.3 million at September 30, 2012 and 2011. Accumulated depreciation for these capital leases totaled $0.9 and $0.9 million at September 30, 2012 and 2011. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2012 were as follows:

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

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

15. Concentration of Credit Risk

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

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

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2012, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty.

AEM' s estimated credit exposure is monitored in terms of the percentage of its customers, including affiliate customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM' s credit department, but are primarily based on external ratings provided by Moody' s Investors Service Inc. (Moody' s) and/or Standard & Poor' s Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2012 and 2011.

	September 30, 2012	September 30, 2011
Investment grade	60 %	54 %
Non-investment grade	40 %	46 %
Total	100 %	100 %

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2012. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody' s. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Natural Gas Distribution Segment(1)	Nonregulated Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$ −	$ 4	$ 4
Non-investment grade counterparties	−	−	−
	$ −	$ 4	$ 4

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

16. Supplemental Cash Flow Disclosures

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

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

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

17. Segment Information

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

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

We operate the Company through the following three segments:

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

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment' s taxes were calculated on a separate return basis.

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

	Year Ended September 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,144,376	$92,604	$1,201,503	$−	$3,438,483
Intersegment revenues	954	154,747	149,800	(305,501)	−
	2,145,330	247,351	1,351,303	(305,501)	3,438,483
Purchased gas cost	1,122,587	−	1,296,179	(304,022)	2,114,744
Gross profit	1,022,743	247,351	55,124	(1,479)	1,323,739
Operating expenses					
Operation and maintenance	353,879	71,521	29,697	(1,484)	453,613
Depreciation and amortization	202,026	31,438	4,061	−	237,525
Taxes, other than income	162,377	15,568	3,128	−	181,073
Asset impairments	−	−	5,288	−	5,288
Total operating expenses	718,282	118,527	42,174	(1,484)	877,499
Operating income	304,461	128,824	12,950	5	446,240
Miscellaneous income (expense)	(12,657)	(1,051)	1,035	(1,971)	(14,644)
Interest charges	110,642	29,414	3,084	(1,966)	141,174
Income from continuing operations before income taxes	181,162	98,359	10,901	−	290,422
Income tax expense	57,314	35,300	5,612	−	98,226
Income from continuing operations	123,848	63,059	5,289	−	192,196
Income from discontinued operations, net of tax	18,172	−	−	−	18,172
Gain on sale of discontinued operations, net of tax	6,349	−	−	−	6,349
Net income	$148,369	$63,059	$5,289	$−	$216,717
Capital expenditures	$546,818	$175,768	$10,272	$−	$732,858

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

18. Selected Quarterly Financial Data (Unaudited)

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

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2012:				
Operating revenues				
Natural gas distribution	$676,113 (1)	$871,067 (2)	$315,634 (3)	$282,516
Regulated transmission and storage	56,759	58,037	67,073	65,482
Nonregulated	444,176	370,763	256,250	280,114
Intersegment eliminations	(93,054)	(74,358)	(62,543)	(75,546)
	1,083,994	1,225,509	576,414	552,566
Gross profit	355,392 (1)	425,787 (2)	293,171 (3)	249,389
Operating income	139,471 (1)	202,432 (2)	81,546 (3)	22,791
Income (loss) from continuing operations	62,384	102,084	28,014	(286)
Income from discontinued operations	6,123	7,027	3,118	1,904
Gain on sale of discontinued operations	–	–	–	6,349
Net income	68,507	109,111	31,132	7,967
Basic earnings per share				
Income (loss) per share from continuing operations	$0.68	$1.12	$0.31	$–
Income per share from discontinued operations	$0.07	$0.08	$0.03	$0.09
Net income per share − basic	$0.75	$1.20	$0.34	$0.09
Diluted earnings per share				
Income (loss) per share from continuing operations	$0.68	$1.12	$0.31	$–
Income per share from discontinued operations	$0.07	$0.08	$0.03	$0.09
Net income per share − diluted	$0.75	$1.20	$0.34	$0.09

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS − (Continued)

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

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

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

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

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

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

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

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

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

None.

ITEM 9A. ***Controls and Procedures.***

Management' s Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company' s disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company' s principal executive officer and principal financial officer have concluded that the Company' s disclosure controls and procedures were effective as of September 30, 2012 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC' s rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management' s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2012, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

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

November 12, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation' s internal control over financial reporting as of September 30, 2012, based on criteria established in Internal Control − Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Atmos Energy Corporation' s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management' s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company' s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of September 30, 2012 and 2011, and the related statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2012 of Atmos Energy Corporation and our report dated November 12, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2012

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth quarter of the fiscal year ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *Other Information.*

Not applicable.

PART III

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

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company' s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013. Information regarding executive officers is reported below:

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2012, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
Robert W. Best	65	15	Executive Chairman of the Board
Kim R. Cocklin	61	6	President and Chief Executive Officer
Louis P. Gregory	57	12	Senior Vice President and General Counsel
Michael E. Haefner	52	4	Senior Vice President, Human Resources
Bret J. Eckert	45	−	Senior Vice President and Chief Financial Officer

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

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

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

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

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

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit

Committee of the Board of Directors is incorporated herein by reference to the Company' s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

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

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company' s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

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

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company' s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant' s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

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

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company' s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant' s fees and services is incorporated herein by reference to the Company' s Definitive Proxy Statement for the Annual Meeting of Shareholders on February 13, 2013.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules.*

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

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

3. Exhibits

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K. The exhibits numbered 10.6(a) through 10.13(e) are management contracts or compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and Chief Financial Officer

Date: November 12, 2012

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POWER OF ATTORNEY

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

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

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

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2012

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

(1) Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession	
2.1(a)	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Midstates) Corp. as Buyer, dated as of May 12, 2011	Exhibit 2.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
2.1(b)	Amendment No. 1 to Asset Purchase Agreement	
2.2	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Georgia) Corp. as Buyer, dated as of August 8, 2012	Exhibit 2.1 to Form 8-K dated August 8, 2012 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation − Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation − Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 3, 2010)	Exhibit 3.2 of Form 8-K dated February 3, 2010 (File No. 1-10042)
	Instruments Defining Rights of Security Holders, Including Indentures	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6	Indenture dated as of March 23, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(a)	Debenture Certificate for the 6 3/4% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.7(b)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(c)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)

4.7(d)	Global Security for the 6.35% Senior Notes due 2017	Exhibit 4.2 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.7(e)	Global Security for the 8.50% Senior Notes due 2019	Exhibit 4.2 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(f)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 10, 2011 (File No. 1-10042)

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

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.5(a)	Guaranty of Algonquin Power & Utilities Corp. dated May 12, 2011	Exhibit 10.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
10.5(b)	Guaranty of Algonquin Power & Utilities Corp. dated August 8, 2012	Exhibit 10.1 to Form 8-K dated August 8, 2012 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.6(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement − Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.6(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement − Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.7(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.7(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.8(a)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	Exhibit 10.14 to Form 10-K for fiscal year ended September 30, 2011 (File No. 1-10042)
10.8(b)*	Amendment No 1 to the Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	
10.9(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.9(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of November 12, 2009)	Exhibit 10.10(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(c)*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan, Effective Date August 5, 2009	Exhibit 10.10(c) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(d)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.9(e)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.10(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.10(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.10(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)
10.11*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2012	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2011 (File No. 1-10042)
10.12*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan, Amended and Restated as of October 1, 2009	Exhibit 10.13 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

10.13(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 10, 2011)	Exhibit 99.1 to Form S-8 dated October 28, 2011 (File No. 333-177593)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13(b)*	Form of Non-Qualified Stock Option Agreement under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(b) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.13(c)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.12(d) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.13(d)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
10.13(e)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	
12	Statement of computation of ratio of earnings to fixed charges	
	Other Exhibits, as indicated	
21	Subsidiaries of the registrant	
23.1	Consent of independent registered public accounting firm, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2012
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
	Interactive Data File	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

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

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

Exhibit 2.1(b)

AMENDMENT NO. 1
TO
ASSET PURCHASE AGREEMENT

THIS AMENDMENT NO. 1 TO ASSET PURCHASE AGREEMENT ("Amendment") is made and entered into as of August 1, 2012, by and between Atmos Energy Corporation, a corporation incorporated in the State of Texas and the Commonwealth of Virginia ("Seller"), and Liberty Energy (Midstates) Corp., a Missouri corporation ("Buyer"), and amends that certain Asset Purchase Agreement, dated May 12, 2011 (the "Agreement"), by and between the parties.

WHEREAS, Seller and Buyer entered into the Agreement on May 12, 2011;

WHEREAS, pursuant to Section 11.1 of the Agreement, Seller and Buyer now desire to amend certain provisions of the Agreement in the manner set forth herein.

NOW THEREFORE, in consideration of the parties' respective covenants, representations, warranties, and agreements hereinafter set forth, and intending to be legally bound hereby, the parties agree as follows:

1. Amended Agreement. The Agreement is amended as follows:

(a) Subsection (b) of Section 2.1 (Purchased Assets) of the Agreement is amended by deleting all existing text of that subsection in its entirety and substituting the following text in its entirety:

> "all Billed Revenues and Unbilled Revenues, each as defined in Section 3.5, which for the avoidance of doubt and notwithstanding any other provision of this Agreement to the contrary, shall constitute Current Assets for purposes of calculating the Adjustment Amount;"

(b) Subsection (a) of Section 2.2 (Excluded Assets) of the Agreement is amended by deleting all existing text of that subsection in its entirety and substituting the word "Reserved".

(c) Section 3.5 (Unbilled Revenues) of the Agreement is amended by deleting all existing text of that subsection in its entirety and substituting the following text in its entirety:

> "On and prior to the Closing Date, Seller shall read all customer meters in their normal cycle and in due course render the related bills to its customers served by the Business. Seller shall also read each daily read transportation customer meter (collectively, "Large Volume Meters") on the day immediately preceding the Closing Date. Seller shall provide Buyer with the last meter reading from each of the Large Volume Meters made on the day immediately preceding the Closing Date as soon as practicable after the Closing Date. After the Closing Date, Buyer shall read the customer meters for their first time, in the normal cycle, and in due course render bills for service during the period between Seller' s last reading in the normal cycle and Buyer' s first reading in the normal cycle to the customers served by the Business. Buyer shall determine the volume of gas sold by Seller prior to the Closing Date through Large Volume Meters by Seller' s meter readings on the day immediately preceding the Closing Date. Buyer shall determine by allocation

the volumes of gas sold through all meters other than Large Volume Meters, by Seller prior to the Closing Date, and by Buyer on and after the Closing Date and prior to its first meter reading, through meters without charts. Such allocation shall be consistent with Seller' s past practices for unbilled revenues. The receivables related to the volume of gas allocable to Seller under this Section but not yet billed to customers served by the Business shall be defined as "Unbilled Revenue." "Billed Revenue" shall mean all outstanding bills to customers served by the Business that have not been paid as of the Closing Date less (i) any offset that results from the difference between installment payments and gas consumed and (ii) allowance for bad debt, which shall be calculated consistent with Seller' s past practices."

(d) Subsection (e) of Section 7.10 (Employee Benefits) of the Agreement is amended by deleting all existing text of that subsection in its entirety and substituting the following text in its entirety:

"Seller shall fully vest all Transferred Employees in their account balances under Seller' s Retirement Savings Plan (the "Seller' s 401(k) Plan"), effective as of the Closing Date. Effective as of the Closing Date, Buyer shall maintain or designate, or cause to be maintained or designated, a defined contribution plan and related trust intended to be qualified under Sections 401(a), 401(k) and 501(a) of the Code (the "Buyer' s 401(k) Plan"). Effective as of the Closing Date, the Transferred Employees shall cease participation in Seller' s 401(k) Plan, and shall commence participation in Buyer' s 401(k) Plan. The Buyer' s 401(k) Plan shall provide for the receipt from Transferred Employees of "eligible rollover distributions" (as such term is defined under Section 402 of the Code), including rollovers of outstanding plan loans under the Seller' s 401(k) Plan (and all assets and liabilities associated thereto). As soon as practicable following the Closing Date, Buyer shall provide Seller with such documents and other information as Seller shall reasonably request to assure itself that the Buyer' s 401(k) Plan is tax-qualified and provides for the receipt of eligible rollover distributions. Each Transferred Employee shall be given the opportunity to receive a distribution of his or her account balance under Seller' s 401(k) Plan and shall be given the opportunity to elect a direct rollover of such account balance, including the rollover of any outstanding plan loans, to the Buyer' s 401(k) Plan, subject to and in accordance with the provisions of such plan and applicable Law. Seller and Buyer shall cooperate in order to facilitate any such distribution or rollover and to effect an eligible rollover distribution for those Transferred Employees who elect to rollover their account balances directly to the Buyer' s 401(k) Plan. With respect to each Transferred Employee who elects to effect an eligible rollover distribution of their account balances to the Buyer' s 401(k) Plan and has an outstanding plan loan under Seller' s 401(k) Plan as of the Closing Date, Seller and Buyer shall cooperate to take such steps as may be necessary to (i) name the trustee of the Buyer' s 401(k) Plan as the obligee of such loan, (ii) obtain an executed written acknowledgement from such Transferred Employee that Buyer' s Plan will be the obligee of such loan, and (iii) permit any such Transferred Employee to make timely loan service payments to Buyer' s 401(k) Plan through payroll deductions by Buyer (or its applicable Affiliate) on or after completion of the eligible rollover distribution. On and after the Closing Date and prior to the completion by any Transferred Employee of an eligible rollover distribution which includes the rollover of an outstanding plan loan, Buyer and Seller shall cooperate to permit such Transferred Employee to make timely loan service payments to Seller' s 401(k) Plan through payroll deductions by Buyer (or its applicable Affiliate)."

(e) Section 8.2 (Conditions to Buyer' s Closing Obligations) of the Agreement is amended by adding a new Subsection (i) following the existing text of that section, which new Subsection (i) shall read in its entirety:

"A FERC waiver effectuating the transfer of transportation capacity to Buyer will be obtained prior to the Closing, or, if a waiver is not obtained prior to the Closing, the Parties shall ensure that the transportation capacity pricing and service to which Seller is currently entitled is preserved through the transaction."

(f) Subsection (b)(ii) of Section 1 (Adjustment Amount) of Appendix A to the Agreement is amended by deleting all existing text of that subsection in its entirety and substituting the following text in its entirety:

""Regulatory Liabilities" means the Value as of the Effective Time of the FERC Accounts related to liabilities to refund or credit amounts to customers through rates and charges in future periods (together with any interest or return thereon), that result specifically from ratemaking action by the Applicable Commission (whether pursuant to a decrease or offset to rate base for ratemaking purposes or pursuant to an authorized recovery or credit mechanism), that are included in Assumed Obligations as of the Effective Time or are imposed on Buyer by any Applicable Commission for rate purposes in connection with the approval of the transaction (and excluding any amounts included in the Closing Net PPE Amount); provided that the rate base offset required pursuant to that certain Unanimous Stipulation and Agreement in Case No. GM-2012-0037 before the Public Service Commission of the State of Missouri (the "Missouri Rate Base Offset") shall, in no circumstance, constitute a Regulatory Liability or affect the calculation of Regulatory Liabilities. For the avoidance of doubt, notwithstanding any provision of the Agreement to the contrary, the Missouri Rate Base Offset shall not affect the calculation of the Adjustment Amount, and the Purchase Price shall not be increased, decreased or otherwise adjusted in respect of the Missouri Rate Base Offset."

(g) The Schedules to the Agreement, other than the Seller Disclosure Schedules, are amended by deleting all existing such Schedules in their entirety and substituting the Schedules of corresponding numbers attached to this Amendment.

2. Miscellaneous.

(a) Capitalized Terms. Unless otherwise defined herein, each of the capitalized terms used herein, but not defined herein, shall have the same meaning given to such term in the Agreement. Terms defined herein that are used in an amended provision of the Agreement shall have the same meaning as their definitions herein.

(b) Entire Agreement. This Amendment will be a valid and binding agreement of the parties only if and when it is fully executed and delivered by the parties, and until such execution and delivery no legal obligation will be created by virtue hereof or any discussions with respect hereto. This Amendment embodies the entire agreement and understanding of the parties hereto in respect of the matters contemplated by this Amendment. This Amendment supersedes all prior agreements and understandings between the parties with respect to such matters contemplated hereby.

(c) Ratification; Interpretation. Except as specifically amended by this Amendment, the Agreement remains in effect in accordance with all terms and conditions contained therein. For the avoidance of doubt, the phrases "as of the date hereof", "as of the date of this Agreement" or words of similar import as used in the Agreement (as amended pursuant to this Amendment) shall mean "as of May 12, 2011" (i.e., the date the Agreement was executed).

(d) Amendment. This Amendment may be amended, modified, or supplemented only by written agreement of Seller and Buyer.

(e) Governing Law. This Amendment (as well as any claim or controversy arising out of or relating to this Amendment or the transactions contemplated hereby) shall be governed by and construed in accordance with the laws of the State of New York, without regard to the conflicts of laws rules thereof that would otherwise require the laws of another jurisdiction to apply.

(f) Delivery. This Amendment may be executed in multiple counterparts (each of which will be deemed an original, but all of which together will constitute one and the same instrument), and may be delivered by facsimile transmission, with such facsimile signature constituting an original for all purposes.

[Signature Page Follows]

IN WITNESS WHEREOF, the parties have caused this Amendment to be signed by their respective duly authorized officers as of the date first above written.

ATMOS ENERGY CORPORATION

By: /s/ FRED E. MEISENHEIMER

Name: Fred E. Meisenheimer

Title: Senior Vice President and Chief Financial Officer

LIBERTY ENERGY (MIDSTATES) CORP.

By: /s/ DAVID BRONICHESKI

Name: David Bronicheski

Title: Treasurer and Secretary

By: /s/ LINDA BEAIRSTO

Name: Linda Beairsto

Title: Authorized Signing Officer

Signature Page to Amendment No. 1 to Asset Purchase Agreement

SCHEDULE 1.1-A

BUYER REQUIRED REGULATORY APPROVALS

APPLICABLE COMMISSIONS

Approval by each Applicable Commission of the joint application of the Parties for the approval of the transactions contemplated by the Agreement, including:

(a) Authorization of Buyer to provide regulated gas distribution service in the applicable jurisdiction upon and following the Closing at the same rates, charges, terms and conditions as set forth in the then current tariffs of Seller with respect to the Business on file with the Applicable Commission, including the issuance or approval of the transfer to Buyer of all certificates of public convenience and necessity and other licenses, authorizations, waivers and approvals previously granted by the Applicable Commission to Seller and required for Buyer to operate the Business as currently operated by Seller.

(b) Approval of the assumption and transfer to Buyer of, and authorization to record and recover in accordance with the terms and conditions then applicable to Seller, the Regulatory Assets and Regulatory Liabilities included in the Purchased Assets and Assumed Obligations, and to record and recover a regulatory asset or liability to reflect unfunded pension plan and post- retirement benefits other than pension obligations, if any, assumed by Buyer, to be amortized over the average remaining service period of employees of the Business expected to receive benefits under such plans.

(c) Approval for Buyer to issue debt, either to third parties or to one or more of its Affiliate parent companies, with respect to the financing of the transaction contemplated by the Agreement, in an amount such that the debt component of the utility' s capital structure does not exceed 50% of such capital structure.

(d) Authorization of the parties to enter into and perform in accordance with the terms of all other documents reasonably necessary and incidental to the performance of the transactions contemplated by the Agreement.

FERC: Any and all approvals of the Federal Energy Regulatory Commission required in connection with the transactions contemplated by the Agreement.

SCHEDULE 1.1-B

PERMITTED ENCUMBRANCES

1. Unrecorded easements, discrepancies or conflicts in boundary lines, shortages in area and encroachments which an accurate and complete survey would disclose, that do not, individually or in the aggregate, materially interfere with Buyer' s operation of the Business or use of any of the Purchased Assets in the manner currently used and do not secure any Excluded Liabilities.
2. All matters of record which would be disclosed by an abstract of title, title opinion or title insurance commitment, that do not, individually or in the aggregate, materially interfere with Buyer' s operation of the Business or use of any of the Purchased Assets in the manner currently used and do not secure any Excluded Liabilities.

SCHEDULE 1.1-C

SELLER REQUIRED REGULATORY APPROVALS

ILLINOIS

Illinois Commerce Commission

1. Joint application for approval of the sale of certain of its assets located in the State of Illinois to Liberty Energy (Midstates) Corp.
2. Order issued approving said sale on June 27, 2012.

IOWA

Iowa State Utilities Board

1. Joint application for approval of the sale of certain of its assets located in the State of Iowa to Liberty Energy (Midstates) Corp.
2. Order issued approving said sale on November 14, 2011.

MISSOURI

Missouri Public Service Commission

1. Joint application for approval of the sale of certain of its assets located in the State of Missouri to Liberty Energy (Midstates) Corp.
2. Order issued approving said sale on March 14, 2012.

FEDERAL

1. FERC−Order Issuing Blanket Certificate of Limited Jurisdiction, *Atmos Energy Corporation*, 138 FERC ¶ 62,319 (March 29, 2012).

SCHEDULE 1.1-D

SELLER' S KNOWLEDGE – LIST OF EMPLOYEES

Name	*Title*
Kevin Akers	President Kentucky/Mid-States Division
Ernie Napier	Vice President, Technical Services Kentucky/Mid-States Division
Kevin Dobbs	Vice President, Operations Kentucky/Mid-States Division
Kenny Malter	Vice President, Gas Supply
Louis Gregory	Senior Vice President, General Counsel & Corporate Secretary
Pace McDonald	Vice President, Tax
Doug Walther	Deputy General Counsel
Greg Waller	Manager, Rates & Regulatory Affairs

SCHEDULE 1.1-E

TERRITORY

1. ILLINOIS: The local natural gas distribution system comprising approximately 702 miles of pipeline of varying diameters from 2-inches to 8-inches, associated with the natural gas distribution system serving the primary markets of Alma, Altamont, Beecher City, Brookport, Brownstown, Carrier Mills, Cowden, Eldorado, Farina, Farmersville, Galatia, Girard, Harrisburg, Huey, Iuka, Joppa, Kinmundy, Metropolis, Middletown, Muddy, New Holland, Raleigh, Salem, St. Elmo, St. Peter, Thayer, Vandalia, Virden, Waggoner, and Xenia.

2. IOWA: The local natural gas distribution system comprising approximately 144 miles of pipeline of varying diameters from 2-inches to 10-inches, associated with the natural gas distribution system serving the primary markets of Keokuk and Montrose.

3. MISSOURI: The local natural gas distribution system comprising approximately 2,179 miles of pipeline of varying diameters from 2-inches to 12-inches, associated with the natural gas distribution system serving the primary markets of Adrian, Alexandria, Amoret, Appleton, Arbela, Arbyrd, Arcadia, Archie, Benton, Bertrand, Bowling Green, Butler, Campbell, Canton, Cardwell, Caruthersville, Chaffee, Charleston, Clarkton, Cooter, Doniphan, East Prairie, Edina, Ewing, Gideon, Gordonville, Greentop, Greenville, Hannibal, Hayti Heights, Hayti, Holcomb, Holland, Hornersville, Howardville, Hume, Ironton, Jackson, Kahoka, Kirksville, Knox City, La Plata, Labelle, LaGrange, Lambert, Lancaster, Lewistown, Lilbourn, Luray, Malden, Marston, Matthews, Memphis, Miner, Monticello, Montrose, Morehouse, Morley, Naylor, Neelyville, New Madrid, North Lilbourn, Oak Ridge, Oran, Palmyra, Passaic, Piedmont, Portageville, Puxico, Queen City, Qulin, Rich Hill, Senath, Sikeston, Steele, Wardell, and Wayland.

4. MISCELLANEOUS: Approximately twenty (20) feet of four-inch (4”) steel pipeline at or near the Kansas/Missouri border, running from the outlet valve on the State Line Meter setting, under State Line Road in the County of Linn, Kansas, to the Kansas/Missouri border.

SCHEDULE 2.1(a)(i)

REAL PROPERTY AND REAL PROPERTY INTERESTS

1. OWNED OFFICE/WAREHOUSE STRUCTURES AND LAND:

a. ILLINOIS

i. 611 N. Main, Harrisburg, IL.

b. IOWA

i. None.

c. MISSOURI

i. 2 Industrial Loop Drive, Hannibal, MO (Seller shall cause its Subsidiary to transfer to Buyer).

ii. Out Lot 50, Hannibal, MO (remediated former MGP site).

iii. 101 E. Mill Street, Butler, MO.

iv. 209 Champ Clark Drive, Bowling Green, MO.

v. 916 Green Street, Kirksville, MO.

SCHEDULE 2.1(a)(i)

REAL PROPERTY AND REAL PROPERTY INTERESTS
(Continued)

2. LEASED OFFICE/WAREHOUSE SPACE:

Illinois

Address	*Type*	*Office Size*	*Warehouse Size*	*Other Size*	*Action Required*	*Status*
136 E. Dean St, Virden 62690	Office	2736	2914		Prior written consent	Complete
224 S. 6th St, Vandalia 62471	Office	1750	2650		Prior written consent	Complete
615 E. 10th St, Metropolis 62960	Office	1200	1250	1125	Prior written consent	Complete

Iowa

Address	*Type*	*Office Size*	*Warehouse Size*	*Other Size*	*Action Required*	*Status*
2547 Hilton Rd, Keokuk 52632	Office	4430	5360		Prior written consent	Discussing with landlord

Missouri

Address	*Type*	*Office Size*	*Warehouse Size*	*Other Size*	*Action Required*	*Status*
100 S. Main, Butler 64730	Other	2000	232		Prior written consent	New lease signed by Liberty
900 Truman Blvd, Caruthersville 63830	Other	4500	1200		Prior written consent	Complete
2370 N. High St, Suite 1, Jackson 63755	Office	2500			Prior written consent	Complete
216 W. Main, Malden 63863	Office	1000		248	Silent	Complete
1024 Linn St, Sikeston 63801	Office	4000	6000		Prior written consent	Complete
113 R S. Main, Ironton 63650	Storage space		375		None	Acknow. still outstanding
617 North Main Piedmont	Storage space		375		None	Liberty to determine if new lease is needed

"Complete" indicates both Consent & Estopel and Acknowledgement have been fully executed.

3. EASEMENTS AND RIGHTS-OF-WAY

a. ILLINOIS: All right, title and interest to all real property (and interests therein and appurtenances thereto), rights-of-way, leases, easements, licenses or other rights to use or have access, servitudes, distribution systems and assets, whether or not of record, including (without limitation) in the counties of Champaign, Clay, Clinton, Effingham, Fayette, Logan, Macoupin, Marion, Massac, Menard, Montgomery, Saline, Sangamon, and Shelby, associated with the high pressure natural gas distribution system service for the primary markets of Alma, Altamont, Beecher City, Brookport, Brownstown, Carrier Mills, Cowden, Eldorado, Farina, Farmersville, Galatia, Girard, Harrisburg, Huey, Iuka, Joppa, Kinmundy, Metropolis, Middletown, Muddy, New Holland, Raleigh, Salem, St. Elmo, St. Peter, Thayer, Vandalia, Virden, Waggoner, and Xenia.

b. IOWA: All right, title and interest to all real property (and interests therein and appurtenances thereto), rights-of-way, leases, easements, licenses or other rights to use or have access, servitudes, distribution systems and assets, whether or not of record, including (without limitation) in the county of Lee, associated with the high pressure natural gas distribution system service for the primary markets of Keokuk and Montrose.

c. MISSOURI: All right, title and interest to all real property (and interests therein and appurtenances thereto), rights-of-way, leases, easements, licenses or other rights to use or have access, servitudes, distribution systems and assets, whether or not of record, including (without limitation) in the counties of Adair, Bates, Butler, Cape Girardeau, Cass, Clark, Dunklin, Henry, Iron, Knox, Lewis, Macon, Marion, Mississippi, New Madrid, Pemiscot, Pike, Ralls, Ripley, Schuyler, Scotland, Scott, St. Clair, Stoddard and Wayne associated with the high pressure natural gas distribution system service for the primary markets of the primary markets of Adrian, Alexandria, Amoret, Appleton, Arbela, Arbyrd, Arcadia, Archie, Benton, Bertrand, Bowling Green, Butler, Campbell, Canton, Cardwell, Caruthersville, Chaffee, Charleston, Clarkton, Cooter, Doniphan, East Prairie, Edina, Ewing, Gideon, Gordonville, Greentop, Greenville, Hannibal, Hayti Heights, Hayti, Holcomb, Holland, Hornersville, Howardville, Hume, Ironton, Jackson, Kahoka, Kirksville, Knox City, La Plata, Labelle, LaGrange, Lambert, Lancaster, Lewistown, Lilbourn, Luray, Malden, Marston, Matthews, Memphis, Miner, Monticello, Montrose, Morehouse, Morley, Naylor, Neelyville, New Madrid, North Lilbourn, Oak Ridge, Oran, Palmyra, Passaic, Piedmont, Portageville, Puxico, Queen City, Qulin, Rich Hill, Senath, Sikeston, Steele, Wardell, and Wayland.

SCHEDULE 2.1(a)(ii)

ALL OTHER NATURAL GAS DISTRIBUTION UTILITY SYSTEM ASSETS

1. HIGH PRESSURE PIPELINE DISTRIBUTION SYSTEM

a. ILLINOIS: All personal property comprising approximately 702 miles of pipeline of varying diameters from 2-inches to 8-inches, associated with the high pressure natural gas distribution system serving the primary markets of Alma, Altamont, Beecher City, Brookport, Brownstown, Carrier Mills, Cowden, Eldorado, Farina, Farmersville, Galatia, Girard, Harrisburg, Huey, Iuka, Joppa, Kinmundy, Metropolis, Middletown, Muddy, New Holland, Raleigh, Salem, St. Elmo, St. Peter, Thayer, Vandalia, Virden, Waggoner, and Xenia.

b. IOWA: All personal property comprising approximately 144 miles of pipeline of varying diameters from 2-inches to 10-inches, associated with the high pressure natural gas distribution system serving the primary markets of Keokuk and Montrose.

c. MISSOURI: All personal property comprising approximately 2,179 miles of pipeline of varying diameters from 2-inches to 12-inches, associated with the high pressure natural gas distribution system serving the primary markets of Adrian, Alexandria, Amoret, Appleton, Arbela, Arbyrd, Arcadia, Archie, Benton, Bertrand, Bowling Green, Butler, Campbell, Canton, Cardwell, Caruthersville, Chaffee, Charleston, Clarkton, Cooter, Doniphan, East Prairie, Edina, Ewing, Gideon, Gordonville, Greentop, Greenville, Hannibal, Hayti Heights, Hayti, Holcomb, Holland, Hornersville, Howardville, Hume, Ironton, Jackson, Kahoka, Kirksville, Knox City, La Plata, Labelle, LaGrange, Lambert, Lancaster, Lewistown, Lilbourn, Luray, Malden, Marston, Matthews, Memphis, Miner, Monticello, Montrose, Morehouse, Morley, Naylor, Neelyville, New Madrid, North Lilbourn, Oak Ridge, Oran, Palmyra, Passaic, Piedmont, Portageville, Puxico, Queen City, Qulin, Rich Hill, Senath, Sikeston, Steele, Wardell, and Wayland.

2. GAS DISTRIBUTION ASSETS

a. ILLINOIS: All personal property associated with the distribution system' s provision of service, including, without limitation, compressors, pumps, motors, dehydrators, treaters, vessels, machinery, vehicles, trailers, fences, tools, lubricants, materials, supplies and spare-parts and computer hardware, and Seller' s interest as lessee in any equipment leased by Seller, to the primary markets of Alma, Altamont, Beecher City, Brookport, Brownstown, Carrier Mills, Cowden, Eldorado, Farina, Farmersville, Galatia, Girard, Harrisburg, Huey, Iuka, Joppa, Kinmundy, Metropolis, Middletown, Muddy, New Holland, Raleigh, Salem, St. Elmo, St. Peter, Thayer, Vandalia, Virden, Waggoner, and Xenia.

b. IOWA: All personal property associated with the distribution system' s provision of service, including, without limitation, compressors, pumps, motors, dehydrators, treaters, vessels, machinery, vehicles, trailers, fences, tools, lubricants, materials, supplies and spare-parts and computer hardware, and Seller' s interest as lessee in any equipment leased by Seller, to the primary markets of Keokuk and Montrose.

c. MISSOURI: All personal property associated with the distribution system' s provision of service, including, without limitation, compressors, pumps, motors, dehydrators, treaters, vessels, machinery, vehicles, trailers, fences, tools, lubricants, materials, supplies and spare-parts and computer hardware, and Seller' s interest as lessee in any equipment leased by Seller, to the primary markets of Adrian, Alexandria, Amoret, Appleton, Arbela, Arbyrd, Arcadia, Archie, Benton, Bertrand, Bowling Green, Butler, Campbell, Canton, Cardwelll, Caruthersville, Chaffee, Charleston, Clarkton, Cooter, Doniphan, East Prairie, Edina, Ewing, Gideon, Gordonville, Greentop, Greenville, Hannibal, Hayti Heights, Hayti, Holcomb, Holland, Hornersville, Howardville, Hume, Ironton, Jackson, Kahoka, Kirksville, Knox City, La Plata, Labelle, LaGrange, Lambert, Lancaster, Lewistown, Lilbourn, Luray, Malden, Marston, Matthews, Memphis, Miner, Monticello, Montrose, Morehouse, Morley, Naylor, Neelyville, New Madrid, North Lilbourn, Oak Ridge, Oran, Palmyra, Passaic, Piedmont, Portageville, Puxico, Queen City, Qulin, Rich Hill, Senath, Sikeston, Steele, Wardell, and Wayland.

SCHEDULE 2.1(i)

ASSETS AND OTHER RIGHTS

ILLINOIS

None.

IOWA

None.

MISSOURI

None.

SCHEDULE 2.2(g)

ALL EXCLUDED AGREEMENTS, CONTRACTS, AND UNDERSTANDINGS

1. Agreements jointly used by the subject Business and other divisions of Seller:

Contractor	*Description*	*Effective Date*	*Term*
Bank of America	P-Card and Travel & Entertainment Card	12/9/2010	Ongoing
McJunkin	Pipe valves & fittings	2/21/2011	Three years
GE Capital Fleet Services	Master Lease Agreement; and related addendum*	1/15/1999	Ongoing
GE Capital Fleet Services	Master Services Agreement ; and related addendum*	1/15/1999	Ongoing
ARI Fleet LT and Automotive Rentals, Inc.	Lease and fleet management services agreement *	5/4/2010	Ongoing
Deere Credit, Inc.	Master Lease Agreement - Equipment leases*	3/10/2003	Two years
US Bank	Retail lockbox	12/16/2009	Three years
CheckFree	Walkin pay centers and e-bill handling	3/31/2006	Ongoing
BillMatrix	Credit Card payment processing	3/1/2011	Negotiating new contract, currently month-to-month
Western Union	Walk-in pay centers	3/31/1997	Ongoing
Fidelity Express	Walk-in pay centers	12/19/2003	Annual auto-renewal
Visa	Acceptance & promotional agreement	5/1/2011	Two years
Contract Callers, Inc.	Outside collection agency	1/1/2005	Ongoing
Professional Finance Co.	Outside collection agency	10/1/2005	Ongoing
Dynamic Recovery Services	Outside collection agency	4/1/2004	Ongoing
HHT Limited	Outside collection agency	5/6/2010	Ongoing
Kubra	Bill printing	7/30/2009	4/30/2013
Societe Generale	ISDA Master Agreement		Ongoing
Barclays Bank PLC	ISDA Master Agreement		Ongoing
CitiGroup Inc.	ISDA Master Agreement		Ongoing
Conoco Phillips	ISDA Master Agreement		Ongoing

Credit Agricole (formerly Calyon)	ISDA Master Agreement	Ongoing
Fifth Third Bank	ISDA Master Agreement	Ongoing
JPMorgan Chase Bank N.A.	ISDA Master Agreement	Ongoing
Wells Fargo Bank, National	ISDA Master Agreement	Ongoing
Shell Energy North America (US)	ISDA Master Agreement	Ongoing
Morgan Stanley	ISDA Master Agreement	Ongoing
BP Corporation North America Inc.	ISDA Master Agreement	Ongoing
BNP Paribas	ISDA Master Agreement	Ongoing
Royal Bank of Canada	ISDA Master Agreement	Ongoing
Bank of Montreal	ISDA Master Agreement	Ongoing
Credit Suisse	ISDA Master Agreement	Ongoing
Deutsche Bank Securities Inc.	ISDA Master Agreement	Ongoing
Goldman, Sachs & Co.	ISDA Master Agreement	Ongoing

* Assets that principally relate to the current operation of the Business that are leased under a lease, contract or agreement set forth on this Schedule 2.2(g) will be transferred to Buyer pursuant to an assignment or partial assignment of the lease schedule or lease of which they are a part (without assignment of the master lease agreement itself or any other lease thereunder); provided, however, that if such lease cannot be assigned to Buyer, such assets shall be subject to Section 7.6(c) of the Agreement.

2. Base NAESB Agreements.

Contract No.	*Description*	*Party*	*Term*
UCG-10835	Gas Supply Agreement - Base Contract (NAESB)	CenterPoint Energy Gas Marketing Company	Ongoing
UCG-10999	Gas Supply Agreement - Base Contract (NAESB)	OGE Energy Resources, Inc.	Ongoing
UCG-11074	Gas Supply Agreement - Base Contract (NAESB)	Tenaska Marketing Ventures	Ongoing

UCG-11105	Gas Supply Agreement - Base Contract (NAESB)	Coral Energy Resources, L.P.	Ongoing
UCG-11105	Gas Supply Agreement - Base Contract (NAESB)	Coral Energy Resources, L.P.	Ongoing
UCG-10835	Gas Supply Agreement - Base Contract (NAESB)	CenterPoint Energy Gas Marketing Company	Ongoing
UCG-10837	Gas Supply Agreement - Base Contract (NAESB)	ConocoPhillips Company	Ongoing
UCG-10999	Gas Supply Agreement - Base Contract (NAESB)	OGE Energy Resources, Inc.	Ongoing
UCG-11105	Gas Supply Agreement - Base Contract (NAESB)	Coral Energy Resources, L.P.	Ongoing
UCG-11313	Gas Supply Agreement - Base Contract (NAESB)	Laclede Energy Resources, Inc.	Ongoing

3. Radio Licenses.

Call Sign / Lease ID	Name	FRN	Radio Service	Status	Expires	Control Point
WNGL827	Atmos Energy Corporation, Mid-States Division	577305	IG	Active	3/1/2013	425 College St., Canton, MO
KDU845	Atmos Energy Corporation, Mid-States Division	577305	IG	Active	4/18/2013	611 N. Main St., Harrisburg, IL
KNAM811	Atmos Energy Corporation, Mid-States Division	577305	IG	Active	11/5/2015	136 E. Dean St., Virden, IL

SCHEDULE 2.2(o)

EXCLUDED ASSETS AND OTHER RIGHTS

ILLINOIS

None.

IOWA

None.

MISSOURI

None.

SCHEDULE 7.1

EXCEPTIONS TO CONDUCT OF BUSINESS IN ORDINARY COURSE

ILLINOIS

None.

IOWA

None.

MISSOURI

None.

SCHEDULE 7.1(c)

CAPITAL INVESTMENTS PROGRAM

1. SEE FY 2011 CAPITAL BUDGET PREVIOUSLY PROVIDED TO BUYER.
2. PROPOSED FY 2012 CAPITAL BUDGET TO BE PROVIDED TO BUYER
   (which in the aggregate will be reasonably consistent with the FY 2011 Capital Budget).

SCHEDULE 7.9(a)

LIST OF BUSINESS EMPLOYEES

ILLINOIS

State Total: 30

Hire Date	Job Name	Work Location	Grade	Pay Basis
1/5/1987	Sr. Service Technician	Metropolis	2	Non Exempt Hrly
8/27/2007	Sr. Construction Operator	Harrisburg	2	Non Exempt Hrly
6/24/1985	Sr. Service Technician	Harrisburg	2	Non Exempt Hrly
9/3/1985	Sr. Service Technician	Metropolis	2	Non Exempt Hrly
11/7/1983	Distribution Operator	Vandalia	3	Non Exempt Hrly
10/1/1983	Operations Supervisor	Harrisburg	5	Exempt Salary
1/26/1987	Sr. Construction Operator	Metropolis	2	Non Exempt Hrly
7/13/1981	Distribution Operator	Metropolis	3	Non Exempt Hrly
8/7/1989	Crew Leader	Harrisburg	3	Non Exempt Hrly
2/24/1987	Sr. MIC Tech	Vandalia	3	Non Exempt Hrly
10/1/1983	Sr. Service Technician	Harrisburg	2	Non Exempt Hrly
10/3/1983	Crew Leader	Vandalia	3	Non Exempt Hrly
1/1/1984	Sr. Construction Operator	Vandalia	2	Non Exempt Hrly
3/13/1980	Operations Assistant	Vandalia	2	Non Exempt Hrly
10/29/1984	Operations Supervisor	Vandalia	5	Exempt Salary
8/27/1979	Crew Leader	Metropolis	3	Non Exempt Hrly
12/23/2002	Operations Assistant	Harrisburg	2	Non Exempt Hrly
10/25/1979	Sr. Construction Operator	Harrisburg	2	Non Exempt Hrly
5/5/1980	Sr. Service Technician	Harrisburg	2	Non Exempt Hrly
11/16/1992	Sr. Service Technician	Metropolis	2	Non Exempt Hrly
6/4/1974	Sr. Service Technician	Vandalia	2	Non Exempt Hrly
5/14/1981	Operations Assistant	Virden	2	Non Exempt Hrly
2/2/1987	Sr. MIC Tech	Harrisburg	3	Non Exempt Hrly
12/1/1985	Sr. Construction Operator	Vandalia	2	Non Exempt Hrly
3/29/1976	Sr. Service Technician	Harrisburg	2	Non Exempt Hrly
7/18/2005	Service Technician	Virden	1	Non Exempt Hrly
8/30/2004	Sr. Service Technician	Vandalia	2	Non Exempt Hrly
4/28/2008	Meter Reader	Virden	1	Non Exempt Hrly
3/17/2003	Sr. Service Technician	Virden	2	Non Exempt Hrly
5/24/2004	Sr. Service Technician	Virden	2	Non Exempt Hrly

IOWA

State Total: 12

Hire Date	Job Name	Work Location	Grade	Pay Basis
4/16/1990	Town Operator	Keokuk	4	Non Exempt Hrly
7/28/2008	Service Technician	Keokuk	1	Non Exempt Hrly

6/1/1978	Distribution Operator	Keokuk	3	Non Exempt Hrly
11/19/ 1990	Crew Leader	Keokuk	3	Non Exempt Hrly
5/7/1979	Operations Assistant	Keokuk	2	Non Exempt Hrly
3/19/1979	Operations Assistant	Keokuk	2	Non Exempt Hrly

3/5/1990	Sr. Construction Operator	Keokuk	2	Non Exempt Hrly
9/1/1973	Operations Manager	Keokuk	6	Exempt Salary
1/24/1972	Sr. Service Technician	Keokuk	2	Non Exempt Hrly
1/11/2010	Meter Reader	Keokuk	1	Non Exempt Hrly
1/9/2006	Project Specialist	Keokuk	4	Exempt Salary
2/12/1990	Operations Supervisor	Keokuk	5	Exempt Salary

MISSOURI

State Total: 63

Hire Date	*Job Name*	*Work Location*	*Grade**	*Pay Basis*
1/25/1971	Operations Assistant	Hannibal	2	Non Exempt Hrly
1/10/1994	Crew Leader	Sikeston	U	Non Exempt Hrly
7/31/2006	Sr. Construction Operator	Jackson	U	Non Exempt Hrly
3/5/1990	Sr. Construction Operator	Hannibal	2	Non Exempt Hrly
5/18/1998	Sr. Construction Operator	Jackson	U	Non Exempt Hrly
8/18/1997	Operations Assistant	Butler	2	Non Exempt Hrly
5/3/1988	Meter Reader	Caruthersville	U	Non Exempt Hrly
1/9/1989	Distribution Operator	Hannibal	3	Non Exempt Hrly
3/16/1999	Sr. Service Technician	Butler	U	Non Exempt Hrly
12/3/1984	Sr. Service Technician	Caruthersville	U	Non Exempt Hrly
12/17/1990	Sr. MIC Tech	Caruthersville	U	Non Exempt Hrly
8/26/1991	Sr. Construction Operator	Sikeston	U	Non Exempt Hrly
6/18/1990	Project Specialist	Sikeston	4	Exempt Salary
12/9/1985	Crew Leader	Butler	U	Non Exempt Hrly
12/9/1996	Sr. Service Technician	Malden	U	Non Exempt Hrly
8/14/1984	Operations Supervisor	Hannibal	5	Exempt Salary
4/16/1979	Sr. Service Technician	Kirksville	U	Non Exempt Hrly
12/16/1998	Operations Assistant	Jackson	2	Non Exempt Hrly
3/12/1984	Operations Assistant	Kirksville	2	Non Exempt Hrly
10/1/1990	Distribution Operator	Hannibal	3	Non Exempt Hrly
8/7/1978	Sr. Service Technician	Malden	U	Non Exempt Hrly
3/15/1985	Sr. Service Technician	Jackson	U	Non Exempt Hrly
1/2/1992	Sr. MIC Tech	Sikeston	U	Non Exempt Hrly
4/23/1982	Sr. Construction Operator	Caruthersville	U	Non Exempt Hrly
11/20/1978	Sr. Service Technician	Sikeston	U	Non Exempt Hrly
12/22/1980	Corrosion Control Technician	Hannibal	3	Non Exempt Hrly
4/9/1982	Sr. Construction Operator	Jackson	U	Non Exempt Hrly
1/1/1990	Sr. Construction Operator	Hannibal	2	Non Exempt Hrly
7/24/1990	Sr. Service Technician	Sikeston	U	Non Exempt Hrly
6/3/1977	Sr. Service Technician	Caruthersville	U	Non Exempt Hrly
6/3/1985	Operations Supervisor	Kirksville	5	Exempt Salary
11/18/1977	Sr. Service Technician	Caruthersville	U	Non Exempt Hrly
6/21/1982	Mgr Public Affairs	Jackson	6	Exempt Salary

5/1/1975	Crew Leader	Caruthersville	U	Non Exempt Hrly
6/30/2008	Construction Operator	Hannibal	1	Non Exempt Hrly
1/14/2008	Sr. Service Technician	Malden	U	Non Exempt Hrly
11/24/ 2008	Meter Reader	Jackson	U	Non Exempt Hrly
11/17/ 2008	Meter Reader	Kirksville	U	Non Exempt Hrly

7/17/2007	Meter Reader	Malden	U	Non Exempt Hrly
1/7/2008	Meter Reader	Sikeston	U	Non Exempt Hrly
5/21/2007	Meter Reader	Butler	U	Non Exempt Hrly
8/6/2007	Service Technician	Jackson	U	Non Exempt Hrly
4/6/2006	Construction Operator	Kirksville	U	Non Exempt Hrly
2/4/1998	Sr. Service Technician	Sikeston	U	Non Exempt Hrly
5/12/1998	Operations Supervisor	Jackson	5	Exempt Salary
7/15/2004	Service Technician	Hannibal	1	Non Exempt Hrly
2/1/1996	Sr. MIC Tech	Jackson	U	Non Exempt Hrly
10/26/1998	Sr. Construction Operator	Hannibal	2	Non Exempt Hrly
2/14/2008	Construction Operator	Jackson	U	Non Exempt Hrly
5/13/2002	Sr. Construction Operator	Butler	U	Non Exempt Hrly
3/16/1994	Operations Supervisor	Malden	5	Exempt Salary
6/27/1997	Sr. MIC Tech	Hannibal	3	Non Exempt Hrly
11/17/1997	Operations Supervisor	Sikeston	5	Exempt Salary
7/16/1990	Sr. Service Technician	Kirksville	U	Non Exempt Hrly
9/17/1987	Sr. Service Technician	Sikeston	U	Non Exempt Hrly
3/11/1996	Sr. Service Technician	Jackson	U	Non Exempt Hrly
7/23/1990	Crew Leader	Kirksville	U	Non Exempt Hrly
6/26/1995	Sr. Construction Operator	Sikeston	U	Non Exempt Hrly
3/12/2007	Sr. Construction Operator	Malden	U	Non Exempt Hrly
5/9/2011	Meter Reader	Sikeston	U	Non Exempt Hrly
5/23/2011	Operations Assistant	Caruthersville	2	Non Exempt Hrly
11/22/2011	Operations Assistant	Sikeston	2	Non Exempt Hrly
8/8/2011	Meter Reader	Hannibal	1	Non Exempt Hrly
				Grand Total: 105

* U = Union

We have two posted positions:

(1) Meter Reader, Vandalia, IL

(2) Meter Reader, Malden, MO – position covered by union contract

Candidate for each position going through pre-employment steps during the week of July 22, 2012. Their hire date will August 1, 2012 or after.

SCHEDULE 7.9(c)

COLLECTIVE BARGAINING UNITS

ILLINOIS: None.

IOWA: None.

MISSOURI: International Brotherhood of Electrical Workers, Local Union 1439, AFL-CIO.

SCHEDULE 7.10(d)

ASSET TRANSFER AMOUNT OF
PENSION LIABILITIES AND ASSETS

Transfer of Pension Liabilities and Assets

For purposes of determining the asset transfer amount:

Terminations Prior to Closing Date

Seller will retain the liability, and no assets will be transferred.

New Hires Prior to Closing

Employees will become participants in the Retirement Savings Plan and will not participate in the Pension Account Plan; no assets will be transferred.

Active Participants at Closing Date

Grandfathered Participants

Assets transferred: Greater of (1) the Pension Account Plan account balance at Closing Date[1] or (2) the lump sum value of the Pension Account Plan grandfathered monthly benefit earned as of the Closing Date

Assumptions: For the lump sum value of the grandfathered benefit, IRS 417(e) interest rates and mortality table in effect for lump sums payable as of the first of the month following the Closing Date

Non-grandfathered Participants

Assets transferred: Pension Account Plan account balance at Closing Date[1]

Assumptions: Not applicable

1 Account balance will include a partial year of pay credits and interest credits if the transaction closes in the middle of a calendar year.

Adjustment Between Closing Date and Actual Transfer Date

For purposes of Section 7.9(e), the Interest Crediting Rate in effect in the Pension Account Plan during the period between Closing Date and Actual Transfer Date will be used for the adjustment.

SCHEDULE 7.10(f)

ASSET TRANSFER AMOUNT OF POST-RETIREMENT HEALTH AND WELFARE BENEFITS

Transfer of Retiree Medical Liabilities and Assets

For purposes of determining the asset transfer amount, Seller will transfer based on financial reporting assumptions as this is the basis for rate recovery.

Discount Rate	Based on high quality corporate bond yields as of the Closing Date
Salary Increase	4.0% per year
Medical/Dental Plan Trend Rate:	
Medical costs	8.00% in fiscal year 2012: reducing 0.5% per year, reaching 5.00% in fiscal year 2018 and after.
Prescription drug costs	8.00% in fiscal year 2012: reducing 0.5% per year reaching 5.50% in fiscal year 2017 and after.
Dental costs	6.00% in fiscal year 2011 and after
Mortality Table	RP2000 White Collar with mortality improvement projected to 2020 using Scale AA
Termination	Rates varying by age and service. Sample rates:

	Age 25	Age 40	Age 55
Rate	12.1%	4.7%	2.2%

Retirement: Rates varying by age:

Age	Rate
55-58	5%
59-60	10%
61	15%
62	40%
63-64	30%
65-69	50%
70	100%

Percentage Covering Spouses	70%
Spouses Ages	Wives 2 years younger than husbands
Participation Rates	95%
Other Assumptions	Other assumptions as used for the Seller' s most recent financial statement disclosures as of September 30, 2011

SCHEDULE 7.10(i)

SEVERANCE ARRANGEMENTS

Seller has no formal severance policy, however Seller' s general practice is 1.5 weeks pay for each full year of service (rounded down) - minimum five weeks, no maximum.

Seller also subsidizes COBRA coverage for the same amount of time as calculated above at a rate same as active-employee rates.

Exhibit 4.1

05428

COMMON STOCK

NUMBER

AN

INCORPORATED UNDER THE LAWS OF THE STATE OF TEXAS AND THE COMMONWEALTH OF VIRGINIA

COMMON STOCK

SHARES

SEE REVERSE FOR CERTAIN DEFINITIONS

Atmos Energy Corporation

CUSIP 049560 10 5

THIS CERTIFIES THAT

SPECIMEN

IS THE OWNER OF

FULLY PAID AND NON-ASSESSABLE SHARES OF THE COMMON STOCK, NO PAR VALUE, OF

Atmos Energy Corporation (the "Company"), transferable on the books of the Company in person or by duly authorized attorney upon surrender of this certificate properly endorsed. This certificate is not valid unless countersigned by the transfer agent and registered by the registrar.

COMMON

Witness the signatures of the Company's duly authorized officers.

Dated

CORPORATE SECRETARY

ATMOS energy

Atmos Energy Corporation

BY

PRESIDENT AND CHIEF EXECUTIVE OFFICER

COUNTERSIGNED AND REGISTERED:
AMERICAN STOCK TRANSFER & TRUST COMPANY, LLC
(BROOKLYN, NY)
TRANSFER AGENT AND REGISTRAR

BY

AUTHORIZED OFFICER

AMERICAN BANK NOTE COMPANY

ATMOS ENERGY CORPORATION

Set forth below is the designation of each class of shares which the Company is authorized to issue. The preferences, limitations and relative rights of each class of shares and each series thereof are set forth in the Articles of Incorporation of the Company, as amended, the Bylaws and resolutions of the Board of Directors filed or which may be filed from time to time with the Secretary of State of the State of Texas and the Corporation Commission of the Commonwealth of Virginia. Preemptive rights of the holders of all shares are denied by the Articles of Incorporation of the Company. This certificate and the shares represented hereby are issued and shall be held subject to said Articles of Incorporation, Bylaws and resolutions of the Board of Directors, all of which are incorporated herein by reference and to all of which the holder hereof, by acceptance of this certificate, assents. The Company will upon request to its Corporate Secretary at its principal place of business or registered office, furnish any shareholder, without charge, a copy of the portion of the Articles of Incorporation or other instruments containing the designations, preferences, limitations and relative rights of all classes of shares and each series thereof.

The following abbreviations, when used in the inscription on the face of this certificate, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM - as tenants in common

TEN ENT - as tenants by the entireties

JT TEN - as joint tenants with right of survivorship and not as tenants in common

UNIF GIFT MIN ACT - .... Custodian ....
(Cust) (Minor)
under Uniform Gifts to Minors
Act ....
(State)

Additional abbreviations may also be used though not in the above list.

For Value Received, _____________ hereby sell, assign and transfer unto

PLEASE INSERT SOCIAL SECURITY OR OTHER IDENTIFYING NUMBER OF ASSIGNEE

____

(PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING POSTAL ZIP CODE, OF ASSIGNEE)

____

____

____ Shares

of the Common stock represented by the within Certificate, and do hereby irrevocably constitute and appoint

____ Attorney

to transfer the said shares on the books of the within named Company with full power of substitution in the premises.

Dated ____

X ____
(SIGNATURE)

NOTICE:

THE SIGNATURE(S) TO THIS ASSIGNMENT MUST CORRESPOND WITH THE NAME(S)

g

X ____
(SIGNATURE)

AS WRITTEN UPON THE FACE OF THE CERTIFICATE IN EVERY PARTICULAR, WITHOUT ALTERATION OR ENLARGEMENT OR ANY CHANGE WHATEVER.

THE SIGNATURE(S) SHOULD BE GUARANTEED BY AN ELIGIBLE GUARANTOR INSTITUTION (BANKS, STOCKBROKERS, SAVINGS AND LOAN ASSOCIATIONS AND CREDIT UNIONS WITH MEMBERSHIP IN AN APPROVED SIGNATURE GUARANTEE MEDALLION PROGRAM), PURSUANT TO SEC, RULE 17Ad-15
SIGNATURE(S) GUARANTEED BY:

Exhibit 10.8(b)

AMENDMENT NO.1
TO THE
ATMOS ENERGY CORPORATION
ANNUAL INCENTIVE PLAN FOR MANAGEMENT
(as amended and restated February 10, 2011)

Pursuant to the authority set forth in Article 10 of the Atmos Energy Corporation Annual Incentive Plan for Management, as amended and restated effective February 10, 2011 (the "Plan"), and resolutions adopted by the Board of Directors of Atmos Energy Corporation (the "Company") on May 3, 2011, the Plan is amended, effective as of September 30, 2011, as follows:

1. Section 6.2 of the Plan is amended, with respect to awards for fiscal years of the Company commencing on and after October 1, 2011, by striking said section and substituting in lieu thereof the following:

6.2 Form of Awards. Awards are paid in cash within ten (10) days following the meeting described in Section 6.1. In addition, if and as the Committee so permits, prior to the commencement of the Performance Period or, in the Committee' s sole discretion, at any time on or before the date that is six (6) months before the end of the Performance Period, provided that a Participant permitted to make such a voluntary election after the commencement of the Performance Period has continuously preformed services for the Company from the beginning of such Performance Period, the Participant may voluntarily elect to convert any Award paid to him in cash in 25 percent increments, in whole or part, into the following forms:

(a) Bonus Stock. The Participant may elect to convert all or a portion of the Award to Bonus Shares, with the value of the Bonus Shares (based on the Fair Market Value of such Bonus Shares as of the Date of Conversion) being equal to 105% of the amount of the Award. Such Bonus Shares shall be unrestricted and shall be granted pursuant to the Long-Term Incentive Plan within ten (10) days following the meeting described in Section 6.1.

(b) Restricted Stock Unit Awards. The Participant may elect to convert all or a portion of the Award to Company Restricted Stock Units, with the value of the Restricted Stock Units (each such Unit being equal to the Fair Market Value of a share of Common Stock as of the Date of Conversion) being equal to 120% of the amount of the Award. Such Restricted Stock Units shall provide that on the date which is three (3) years from the Date of Conversion (the "Distribution Date"), but in no event later than ten (10) days following the Distribution Date, the Participant shall receive a distribution of shares of Common Stock equal in number to the number of Restricted Stock Units determined under this paragraph (b). These Restricted Stock Units will be granted as time-lapse restricted stock units pursuant to the Long-Term Incentive Plan within ten (10) days following the meeting described in Section 6.1.

IN WITNESS WHEREOF, the Company has caused this AMENDMENT NO. 1 TO THE ATMOS ENERGY CORPORATION ANNUAL INCENTIVE PLAN FOR MANAGEMENT (AS AMENDED AND RESTATED FEBRUARY 10, 2011), to be executed in its name and on its behalf this 22nd day of August, 2012, effective as of the date provided herein.

ATMOS ENERGY CORPORATION

By: /s/ KIM R. COCKLIN
Kim R. Cocklin
President and Chief Executive Officer

Exhibit 10.13(d)

AWARD AGREEMENT OF TIME-LAPSE
RESTRICTED STOCK UNITS
UNDER THE ATMOS ENERGY CORPORATION
1998 LONG-TERM INCENTIVE PLAN

This Award Agreement of Time-Lapse Restricted Stock Units ("Award Agreement") is dated as of May 1, 2012, by and between Atmos Energy Corporation, a Texas and Virginia corporation (the "Company"), and **you** ("Grantee"), pursuant to the Company' s 1998 Long-Term Incentive Plan (the "Plan"). Capitalized terms that are used, but not defined, in this Award Agreement shall have the meaning set forth in the Plan.

1. <u>Grant and Description of Units</u>.

Pursuant to authorization by the Human Resources Committee of the Board (the "Committee"), which has been designated by the Board to administer the Plan, the Company hereby grants to the Grantee time-lapse restricted stock units ("Units") under the Plan, for no consideration from the Grantee, with the restrictions set forth below. Each such Unit shall be a notional share of common stock of the Company ("Common Stock"), with the value of each Unit being equal to the Fair Market Value of a share of Common Stock at any time. No physical certificates representing the number of Units awarded shall be issued to the Grantee, but an account shall be established and maintained for the Grantee, in which each grant of Units to the Grantee shall be recorded. During the time of the restriction period provided for in Section 2 below, the Grantee shall not have any of the rights of a shareholder of the Company with respect to the Units, except with respect to the payment of cash dividend equivalents during such period, as provided for in Section 6 below.

2. <u>Restrictions on Alienation of Units</u>.

Units awarded hereunder may not be sold, transferred, pledged, assigned, or otherwise alienated in any manner, whether voluntarily, by operation of law, or otherwise, until the restrictions on the Units are removed and the Units are delivered to the Grantee in the form of shares of Common Stock in the manner described below in Section 8.

3. <u>Vesting of Units</u>.

If the Grantee has attained the age of 55 and completed three (3) consecutive years of service with the Company (referred to as "Retirement Eligible") on the date of the grant of the Units, he or she shall be vested in the Units on the later of June 1 of the year in which the grant is made or the date of the grant. If the Grantee becomes Retirement Eligible after the date of grant and prior to the date for distribution of shares of Common Stock represented by the Units, the Grantee shall be vested in the Units at the later of June 1 of the year in which he or she becomes Retirement Eligible or the actual date during such year that he or she becomes Retirement Eligible. However, the Grantee shall not be entitled to the removal of the restrictions on such Units provided for in Section 2 above or to a distribution of shares of Common Stock represented by the number of Units until the time provided for in Section 8 below. In addition, the Grantee' s portion of applicable payroll (FICA) taxes shall be withheld from the first scheduled bi-weekly paycheck in December of the year in which such vesting occurs. The amount of payroll taxes due shall be based on the Fair Market Value of the shares of Common Stock represented by the number of Units as of the last business day of the pay period to which the first scheduled payroll check in December applies.

4. Forfeiture of Units.

If the Grantee is not otherwise vested as provided in Section 3 above, all Units granted shall be forfeited if the Grantee has a voluntary or involuntary Termination of Service for any reason other than as described below in Section 5. Each Grantee, by his or her acceptance of the Units, agrees to execute any documents requested by the Company in connection with such forfeiture. Such provisions with respect to forfeited Units shall be specifically performable by the Company in a court of equity or law. Upon any forfeiture, all rights of the Grantee with respect to the forfeited Units shall cease and terminate, without any further obligation on the part of the Company.

5. Removal of Restrictions.

(a) Death, Disability, Certain Involuntary Terminations and Terminations following a Change in Control.

At the time and on the date of the Grantee' s death, Termination of Service due to Total and Permanent Disability, involuntary Termination of Service due to a general reduction in force or specific elimination of the Grantee' s job, or Termination of Service for any reason following a Change in Control, while employed by the Company or a Subsidiary, all Units shall be vested and all other restrictions placed on the Units shall be removed. The Grantee, or his or her legal representatives, beneficiaries or heirs shall then be entitled to a distribution, as provided in Section 8 below, of shares of Common Stock equal in number to the number of Units set forth in Section 1 above.

(b) Retirement.

At the time and on the date of the Grantee' s Retirement on or after becoming Retirement Eligible, no distribution of Units shall occur and the restrictions provided for in Section 2 above shall remain in place until such time as the Grantee, or his or her legal representatives, beneficiaries or heirs shall be entitled to a distribution, as provided in Section 8 below, of shares of Common Stock equal in number to the number of Units set forth in Section 1 above.

6. Payment of Cash Dividend Equivalents.

Cash dividend equivalents shall be paid on the Units to the Grantee through the Company payroll system in an amount equal to the cash dividends actually paid each calendar quarter on the Company' s issued and outstanding shares of Common Stock. Such cash dividend equivalents shall be paid at the end of the payroll period in which such cash dividends are actually paid to the Company' s shareholders and shall cease as of the Distribution Date (as defined in Section 8 below). However, the payment of cash dividend equivalents shall not be considered to be "eligible compensation," as such term is defined under either the Company' s Retirement Savings Plan or Pension Account Plan.

7. Adjustment Upon Changes in Stock.

If there shall be any change in the number of shares of Common Stock outstanding resulting from subdivision, combination, or reclassification of shares, or through merger, consolidation, reorganization, recapitalization, stock dividend, stock split or other change in the corporate structure, an appropriate adjustment in the number of Units with respect to which restrictions have not lapsed shall be made by the Committee. Depending upon the change in corporate structure, the Committee shall issue additional Units or substitute Units to the Grantee for his or her account, which shall have the same restrictions, terms and conditions as the original Units. Any such adjustment shall be in accordance with the applicable provisions of Section 14 and/or Section 15 of the Plan.

8. Distribution of Common Stock or Cash.

As soon as administratively possible, as determined solely by the Company, following the earlier of the date of the occurrence of a termination event described in Section 5(a) above or the date which is three (3) years from the date of grant of the Units (such date being referred to as the "Distribution Date"), but in no event later than 90 days following the Distribution Date, the Grantee shall receive a distribution, as provided herein, of shares of Common Stock equal in number to the number of Units set forth in Section 1 above (subject to the withholding requirements set forth in Section 9 below), provided the Grantee has been an employee of the Company or a Subsidiary with continuous service from the date of grant to the Distribution Date, except in the event of the Grantee' s Termination of Service or Retirement as discussed in Section 5 above. Notwithstanding the immediately preceding sentence, in the case of a distribution of shares of Common Stock on account of any Termination of Service as provided for above in Section 5 above, other than death, a distribution of the number of such shares, determined after application of the withholding requirements set forth in Section 9 below, plus any dividends payable with respect to such number of shares, on behalf of the Grantee, if the Grantee is a "specified employee" as defined in §1.409A-1(i) of the Final Regulations under Code Section 409A, to the extent otherwise required under Section 409A, shall not occur until the date which is six (6) months following the date of the Grantee' s Termination of Service (or, if earlier, the date of death of the Grantee). Upon a distribution of shares of Common Stock as provided herein, the

Company shall cause the Common Stock then being distributed to be registered in the Grantee' s name, but shall not issue certificates for the Common Stock unless the Grantee requests delivery of the certificates for the Common Stock, in writing in accordance with the procedures established by the Company. The Company shall deliver certificates to the Grantee as soon as administratively practicable following the Company' s receipt of a written request from the Grantee for delivery of the certificates. From and after the date of receipt of such distribution, the Grantee or the Grantee' s legal representatives, beneficiaries or heirs, as the case may be, shall have full rights of transfer or resale with respect to such shares subject to applicable state and federal regulations. Notwithstanding any provisions of this Award Agreement to the contrary, in lieu of a distribution of shares of Common Stock, the Company shall have the option to settle the payment of some or all of the Units in an economically equivalent amount of cash.

9. <u>Withholding Requirements</u>.

Upon the removal or lapse of the restrictions on the Units, the number of shares of Common Stock to be distributed by the Company to the Grantee, which are equal to the number of Units set forth in Section 1 above, or an economically equivalent amount of cash, as discussed in Section 8 above, shall be subject to applicable withholding requirements for income and employment taxes (unless withheld earlier at the time of vesting, as described in Section 3 above) arising from the removal or lapse of the restrictions on the Units. However, if the Grantee is a "specified employee" as defined in §1.409A-1(i) of the Final Regulations under Code Section 409A who is subject to the six (6) months delay provided for in Section 8 above, the Company shall, on the date of the Grantee' s Termination of Service, based on the value of a share of Common Stock on such date, withhold the number of shares attributable to any employment taxes not withheld earlier and shall, on the date which occurs six (6) months following the date of the Grantee' s Termination of Service (or, if earlier, the date of death of the Grantee), based on the value of a share of Common Stock on such date, withhold the number of shares attributable to income taxes. Dividends will also be payable on such date to the Grantee for such delay period based on the net number of shares.

10. <u>Modification</u>.

This Award Agreement may be changed or modified without the Grantee' s consent or signature, if the Company determines, in its sole discretion, that such change or modification is necessary for purposes of compliance with or exemption from the requirements of Section 409A of the Code and any regulations or other guidance issued thereunder, or otherwise to comply with any law.

Grantee acknowledges that as of the grant date, this Award Agreement and the Plan set forth the entire understanding between Grantee and the Company regarding the acquisition of the Units granted under the Plan and supersede all prior oral and written agreements on this subject. By Grantee' s electronic acceptance and the signature of the Company' s representative below, Grantee and the Company agree that the Units are granted under and governed by this Award Agreement and the Plan. Grantee has reviewed and fully understands all provisions of this Award Agreement and the Plan in their entirety.

ATMOS ENERGY CORPORATION

By: /s/ Kim R. Cocklin

Kim R. Cocklin
President and Chief Executive Officer

Exhibit 10.13(e)

AWARD AGREEMENT OF PERFORMANCE-BASED RESTRICTED STOCK UNITS UNDER THE ATMOS ENERGY CORPORATION 1998 LONG-TERM INCENTIVE PLAN

This Award Agreement of Performance-Based Restricted Stock Units ("Award Agreement") is dated as of May 1, 2012, by and between Atmos Energy Corporation, a Texas and Virginia corporation (the "Company"), and **you** ("Grantee"), pursuant to the Company' s 1998 Long-Term Incentive Plan (the "Plan"). Capitalized terms that are used, but not defined, in this Award Agreement shall have the meaning set forth in the Plan.

1. Grant and Description of Units.

Pursuant to authorization by the Human Resources Committee of the Board (the "Committee"), which has been designated by the Board to administer the Plan, the Company hereby grants to the Grantee performance-based restricted stock units ("Units") under the Plan, for no consideration from the Grantee, with the restrictions set forth below. Each such Unit shall be a notional share of common stock of the Company ("Common Stock"), with the value of each Unit being equal to the Fair Market Value of a share of Common Stock at any time. No physical certificates representing the number of Units awarded shall be issued to the Grantee, but an account shall be established and maintained for the Grantee, in which each grant of Units to the Grantee shall be recorded, with the final number of Units as determined in accordance with Section 3 or Section 5 below. Until the final number of Units is determined, the Grantee shall not have any of the rights of a shareholder of the Company with respect to the Units, except for the crediting of dividend equivalents as provided for in Section 6 below.

2. Restrictions on Alienation of Units.

Units awarded hereunder may not be sold, transferred, pledged, assigned, or otherwise alienated in any manner, whether voluntarily, by operation of law, or otherwise, until the restrictions on the Units are removed and the Units are delivered to the Grantee in the form of shares of Common Stock in the manner described below in Section 8.

3. Number of Units Awarded.

Except as provided in Section 5(a) below, the number of Units ultimately to be awarded to the Grantee upon vesting is contingent upon the cumulative amount of earnings per share achieved by the Company for the three year measurement cycle, Fiscal Years 2012 through 2014 (October 1, 2011 through September 30, 2014). The percentage of Units earned for each level of the cumulative amount of earnings per share is illustrated in the performance schedule below. In addition, should the performance levels achieved be between the stated criteria below, straight-line interpolation shall be used. For example, should the cumulative amount of earnings per share for the three-year period be $, the percentage of Units earned would be 125% of the number of Units originally granted. In addition, the performance targets and actual performance attainment for such Units will exclude any mark-to-market gains or losses recognized by the Company' s nonregulated operations.

Performance-Based Restricted Stock Units
Performance Schedule for Grant of Performance Period FY 2012-2014

Performance Level	Cumulative 3-Yr. EPS	Restricted Stock Units Earned	
Below Threshold	Less than $	0	%
Threshold	$	50	%
Target	$	100	%
Maximum	$	150	%

4. Forfeiture of Units.

All Units granted shall be forfeited if, prior to the removal of restrictions on the Units awarded hereunder as provided below in Section 8, the Grantee has a voluntary or involuntary Termination of Service for any reason other than as described below in Section 5. Each Grantee, by his or her acceptance of the Units, agrees to execute any documents requested by the Company in connection with such forfeiture. Such provisions with respect to forfeited Units shall be specifically performable by the Company in a court of equity or law. Upon any forfeiture, all rights of the Grantee with respect to the forfeited Units shall cease and terminate, without any further obligation on the part of the Company.

5. Removal of Restrictions.

(a) Death, Disability, Certain Involuntary Terminations and Terminations following a Change in Control.

At the time and on the date of the Grantee' s death, Termination of Service due to Total and Permanent Disability, involuntary Termination of Service due to a general reduction in force or specific elimination of the Grantee' s job, or Termination of Service for any reason following a Change in Control, while employed by the Company or a Subsidiary, all restrictions placed on each Unit awarded shall be removed, and the measurement cycle for purposes of Section 6 and Section 8 below shall be deemed to have ended. The prorated number of Units awarded shall be determined by multiplying the percentage of Units awarded at the "Target" performance level discussed above in Section 3, by the ratio of actual months of service to 36 months of the original measurement cycle, with the resulting product being increased, if appropriate, as provided below in Section 6. The Grantee, or his or her legal representatives, beneficiaries or heirs shall be entitled to a distribution, as provided in Section 8 below, of shares of Common Stock equal in number to such prorated number of Units.

(b) Retirement.

At the time and on the date of the Grantee's Retirement on or after attaining the age of 55 and completing at least three (3) consecutive years of service with the Company at the time of such Retirement, the restrictions placed on the Units under Section 2 above shall not be removed and the percentage of Units earned shall not be determined until the end of the measurement cycle. The number of Units awarded shall be determined by multiplying the ratio of actual months of service to 36 months of the original measurement cycle by the percentage of Units earned, based on the actual performance achieved over the original measurement cycle, as discussed above in Section 3, with the resulting product being increased, if appropriate, as provided below in Section 6. The Grantee, or his or her legal representatives, beneficiaries or heirs shall be entitled to a distribution, as provided in Section 8 below, of shares of Common Stock equal in number to such prorated number of Units.

6. Credit of Dividend Equivalents.

Immediately prior to distribution of Units as described above in Section 5 or below in Section 8, the Grantee's account shall be credited with a number of Units which are based on the amount of dividends that are declared and paid on shares of Common Stock during each fiscal quarter of the measurement cycle, determined in accordance with Section 3 or Section 5 above ("dividend equivalents"). The number of Units upon which dividend equivalents shall be credited for the benefit of the Grantee is the total number of Units finally determined to have been earned by the Grantee at the end of the measurement cycle in accordance with Section 3 or Section 5 above, as appropriate. The total amount of each quarterly dividend equivalent shall be converted to the number of Units attributable to that quarterly dividend equivalent, by dividing such dividend equivalent amount by the average of the high and low prices of the Common Stock on the last trading day of the month during each quarter that such dividends are paid during the appropriate measurement cycle.

7. Adjustment Upon Changes in Stock.

If there shall be any change in the number of shares of Common Stock outstanding resulting from subdivision, combination, or reclassification of shares, or through merger, consolidation, reorganization, recapitalization, stock dividend, stock split or other change in the corporate structure, an appropriate adjustment in the number of Units with respect to which restrictions have not lapsed shall be made by the

Committee. Depending upon the change in corporate structure, the Committee shall issue additional Units or substitute Units to the Grantee for his or her account, which shall have the same restrictions, terms and conditions as the original Units. Any such adjustment shall be in accordance with the applicable provisions of Section 14 and/or Section 15 of the Plan.

8. Distribution of Common Stock or Cash.

The Grantee shall receive a distribution of whole shares of Common Stock equal in number to the number of Units finally determined to be earned as set forth in Section 3 or Section 5(a) above, as the case may be, increased, if appropriate, as provided in Section 6 above (subject to the withholding requirements set forth in Section 9 below), provided the Grantee has been an employee of the Company or a Subsidiary with continuous service during the entire term of the measurement cycle, except in the event of the Grantee' s Termination of Service or Retirement as discussed above in Section 5. Distribution of shares of Common Stock shall occur as soon as administratively possible, as determined solely by the Company, following the last trading day of the quarter in which the measurement cycle ends as provided for in either Section 3 or Section 5(a) above, as the case may be (such day being referred to as the "Distribution Date"), but in no event later than 90 days following the Distribution Date. Notwithstanding the immediately preceding sentence, in the case of a distribution of shares of Common Stock on account of any Termination of Service as provided for in Section 5 above, other than death, a distribution of the number of such shares, determined after application of the withholding requirements set forth in Section 9 below, plus any dividends payable with respect to such number of shares, on behalf of the Grantee, if the Grantee is a "specified employee" as defined in §1.409A-1(i) of the Final Regulations under Code Section 409A, to the extent otherwise required under Section 409A, shall not occur until the date which is six (6) months following the date of the Grantee' s Termination of Service (or, if earlier, the date of death of the Grantee). Upon a distribution of shares of Common Stock as provided herein, the Company shall cause the Common Stock then being distributed to be registered in the Grantee' s name, but shall not issue certificates for the Common Stock unless the Grantee requests delivery of the certificates for the Common Stock, in writing in accordance with the procedures established by the Company. The Company shall deliver certificates to the Grantee as soon as administratively practicable following the Company' s receipt of a written request from the Grantee for delivery of the certificates. From and after the date of receipt of such distribution, the Grantee or the Grantee' s legal representatives, beneficiaries or heirs, as the case may be, shall have full rights of transfer or resale with respect to such shares subject to applicable state and federal regulations. Notwithstanding any provisions of this Award Agreement to the contrary, in lieu of a distribution of shares of Common Stock, the Company shall have the option to settle the payment of some or all of the Units in an economically equivalent amount of cash.

9. Withholding Requirements.

Upon the removal or lapse of the restrictions on the Units, the number of shares of Common Stock to be distributed by the Company to the Grantee, which are equal to the number of Units finally determined to be earned by the Grantee as set forth in Sections 3 or Section 5(a) and Section 6 above, or an economically equivalent amount of cash, as discussed in Section 8 above, shall be subject to applicable withholding requirements for income and employment taxes arising from the removal or lapse of the restrictions on the Units. However, if the Grantee is a "specified employee" as defined in §1.409A-1(i) of the Final Regulations under Code Section 409A who is subject to the six (6) months delay provided for in Section 8 above, the Company shall, on the date of the Grantee' s Termination of Service, based on the value of a share of Common Stock on such date, withhold the number of shares attributable to any employment taxes and shall, on the date which occurs six (6) months following the date of the Grantee' s Termination of Service (or, if earlier, the date of death of the Grantee), based on the value of a share of Common Stock on such date, withhold the number of shares attributable to income taxes. Dividends for such delay period will also be payable to the Grantee on such date based on the final net number of shares.

10. Modification.

This Award Agreement may be changed or modified without the Grantee' s consent or signature, if the Company determines, in its sole discretion, that such change or modification is necessary for purposes of compliance with or exemption from the requirements of Section 409A of the Code and any regulations or other guidance issued thereunder, or otherwise to comply with any law.

Grantee acknowledges that as of the grant date, this Award Agreement and the Plan set forth the entire understanding between Grantee and the Company regarding the acquisition of the Units granted under the Plan and supersede all prior oral and written agreements on this subject. By Grantee' s electronic acceptance and the signature of the Company' s representative below, Grantee and the Company agree that the Units are granted under and governed by this Award Agreement and the Plan. Grantee has reviewed and fully understands all provisions of this Award Agreement and the Plan in their entirety.

ATMOS ENERGY CORPORATION

By: /s/ Kim R. Cocklin

Kim R. Cocklin
President and Chief Executive Officer

Exhibit 12

Atmos Energy Corporation

Computation of Earnings to Fixed Charges

	Year Ended September 30				
	2012	2011	2010	2009	2008
	(Dollars in thousands)				
Income from continuing operations before provision for income taxes per statement of income	$290,422	$296,407	$309,054	$268,636	$271,216
Add:					
Portion of rents representative of the interest factor	12,623	13,229	13,565	12,768	12,541
Interest on debt & amortization of debt expense	141,174	150,763	154,188	152,740	137,474
Income as adjusted	$444,219	$460,399	$476,807	$434,144	$421,231
Fixed charges:					
Interest on debt & amortization of debt expense (1)	$141,174	$150,763	$154,188	$152,740	$137,474
Capitalized interest (2)	2,642	1,690	3,860	4,583	2,879
Rents	37,868	39,686	40,696	38,304	37,624
Portion of rents representative of the interest factor (3)	12,623	13,229	13,565	12,768	12,541
Fixed charges (1)+(2)+(3)	$156,439	$165,682	$171,613	$170,091	$152,894
Ratio of earnings to fixed charges	2.84	2.78	2.78	2.55	2.76

Exhibit 21

SUBSIDIARIES OF ATMOS ENERGY CORPORATION

Name	State of Incorporation	Percent of Ownership
ATMOS ENERGY HOLDINGS, INC. (wholly-owned by Atmos Energy Corporation)	Delaware	100%
BLUE FLAME INSURANCE SERVICES, LTD (wholly-owned by Atmos Energy Corporation)	Bermuda	100%
ATMOS ENERGY SERVICES, LLC (a limited liability company) (wholly-owned by Atmos Energy Holdings, Inc.)	Delaware	100%
EGASCO, LLC (a limited liability company) (wholly-owned by Atmos Energy Holdings, Inc.)	Texas	100%
ATMOS ENERGY MARKETING, LLC (a limited liability company) (wholly-owned by Atmos Energy Holdings, Inc.)	Delaware	100%
ATMOS POWER SYSTEMS, INC. (a wholly-owned subsidiary of Atmos Energy Holdings, Inc.)	Georgia	100%
ATMOS PIPELINE AND STORAGE, LLC (a limited liability company) (wholly-owned by Atmos Energy Holdings, Inc.)	Delaware	100%
UCG STORAGE, INC. (wholly-owned by Atmos Pipeline and Storage, LLC)	Delaware	100%
WKG STORAGE, INC. (wholly-owned by Atmos Pipeline and Storage, LLC)	Delaware	100%
ATMOS EXPLORATION AND PRODUCTION, INC. (wholly-owned by Atmos Pipeline and Storage, LLC)	Delaware	100%

Name	State of Incorporation	Percent of Ownership
TRANS LOUISIANA GAS PIPELINE, INC. (wholly-owned by Atmos Pipeline and Storage, LLC)	Louisiana	100 %
TRANS LOUISIANA GAS STORAGE, INC. (wholly-owned by Atmos Pipeline and Storage, LLC)	Delaware	100 %
ATMOS GATHERING COMPANY, LLC (a limited liability company) (wholly-owned by Atmos Pipeline and Storage, LLC)	Delaware	100 %
PHOENIX GAS GATHERING COMPANY (wholly-owned by Atmos Gathering Company, LLC)	Delaware	100 %
FORT NECESSITY GAS STORAGE, LLC (a limited liability company) (wholly-owned by Atmos Pipeline and Storage, LLC)	Delaware	100 %

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements (Form S-3, No. 33-37869; Form S-3, No. 33-58220; Form S-3D/A, No. 33-70212; Form S-3, No. 33-56915; Form S-3/A, No. 333-03339; Form S-3/A, No. 333-32475; Form S-3/A, No. 333-50477; Form S-3, No. 333-95525; Form S-3/A, No. 333-93705; Form S-3, No. 333-75576; Form S-3D, No. 333-113603; Form S-3, No. 333-118706; Form S-3D, No. 333-155666; Form S-3ASR, No. 333-165818; Form S-4, No. 333-13429; Form S-8, No. 33-57695; Form S-8, No. 33-57687; Form S-8, No. 333-32343; Form S-8, No. 333-46337; Form S-8, No. 333-73145; Form S-8, No. 333-73143; Form S-8, No. 333-63738; Form S-8, No. 333-88832; Form S-8, No. 333-116367; Form S-8, No. 333-138209; Form S-8, No. 333-145817; Form S-8, No. 333-155570; Form S-8, No. 333-166639; and Form S-8, No. 333-177593) of Atmos Energy Corporation and in the related Prospectuses of our reports dated November 12, 2012, with respect to the consolidated financial statements and schedule of Atmos Energy Corporation and the effectiveness of internal control over financial reporting of Atmos Energy Corporation, included in this Annual Report (Form 10-K) for the year ended September 30, 2012.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 12, 2012

EXHIBIT 31

RULE 13a-14(a)/15d-14(a) CERTIFICATIONS

I, Kim R. Cocklin, certify that:

1. I have reviewed this Annual Report on Form 10-K of Atmos Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant' s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant' s internal control over financial reporting that occurred during the registrant' s most recent fiscal quarter (the registrant' s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant' s internal control over financial reporting; and
5. The registrant' s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant' s auditors and the audit committee of registrant' s board of directors (or persons performing equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant' s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant' s internal control over financial reporting.

Date: November 12, 2012

/s/ KIM R. COCKLIN

Kim R. Cocklin

President and Chief Executive Officer

I, Bret J. Eckert, certify that:

1. I have reviewed this Annual Report on Form 10-K of Atmos Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant' s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant' s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant' s internal control over financial reporting that occurred during the registrant' s most recent fiscal quarter (the registrant' s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant' s internal control over financial reporting; and

5. The registrant' s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant' s auditors and the audit committee of registrant' s board of directors (or persons performing equivalent functions):

   (a) All significant deficiencies or material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant' s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant' s internal control over financial reporting.

Date: November 12, 2012

/s/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the Annual Report of Atmos Energy Corporation (the “Company”) on Form 10-K for the fiscal year ended September 30, 2012, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kim R. Cocklin, President and Chief Executive Officer of the Company, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

November 12, 2012

/s/ KIM R. COCKLIN
Kim R. Cocklin
President and Chief Executive Officer

A signed original of this written statement has been provided to Atmos Energy Corporation and will be retained by Atmos Energy Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the Annual Report of Atmos Energy Corporation (the "Company") on Form 10-K for the fiscal year ended September 30, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bret J. Eckert, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

November 12, 2012

/s/ BRET J. ECKERT
Bret J. Eckert
Senior Vice President and Chief Financial Officer

A signed original of this written statement has been provided to Atmos Energy Corporation and will be retained by Atmos Energy Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Stock and Other Compensation Plans (Table)

12 Months Ended Sep. 30, 2012

Stock and Other Compensation Tables [Abstract]

Schedule of restricted stock activity

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

Schedule of stock option activity

	2012		2011		2010	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Exercise Price**
Outstanding at beginning of year	86,766	$ 22.16	434,962	$ 22.46	611,227	$ 21.88
Granted	-	-	-	-	-	-
Exercised	(76,672)	21.79	(348,196)	22.54	(176,265)	20.44
Forfeited	-	-	-	-	-	-
Expired	-	-	-	-	-	-
Outstanding at end of year(1)	10,094	$ 24.95	86,766	$ 22.16	434,962	$ 22.46
Exercisable at end of year(2)	10,094	$ 24.95	86,766	$ 22.16	434,962	$ 22.46

Schedule of outstanding and exercisable options

	Options Outstanding and Exercisable		
Range of Exercise Prices	**Number of Options**	**Weighted Average Remaining Contractual Life (in years)**	**Weighted Average Exercise Price**
$21.23 to $22.99	2,164	0.4	$ 21.23
$23.00 to $25.95	7,930	2.1	$ 25.95
$21.23 to $25.95	10,094	1.7	$ 24.95

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

Financial Instruments (Details) (USD $)	12 Months Ended Sep. 30, 2012 Bcf	Sep. 30, 2011	Sep. 30, 2010
Derivatives Fair Value [Line Items]			
Derivative Assets Current	$ 24,707,000	$ 18,344,000	
Derivative Assets Noncurrent	2,283,000	998,000	
Derivative Liabilities Current	85,381,000	15,453,000	
Derivative Liabilities Noncurrent	9,206,000	78,089,000	
Total Financial Instruments	(91,383,000)	(104,327,000)	
Effect of Fair Value Hedges on Results of Operations [Abstract]			
Commodity contracts	(30,266,000)	(16,552,000)	(34,650,000)
Fair value adjustment for natural gas inventory designated as the hedged item	5,797,000	(9,824,000)	(19,867,000)
Total impact on purchased gas cost	24,469,000	26,376,000	54,517,000
Basis ineffectiveness	1,170,000	803,000	(1,272,000)
Timing ineffectiveness	23,299,000	25,573,000	55,789,000
Cash Flow Hedge [Line Items]			
Loss reclassified from AOCI into purchased gas for effective portion of commodity contracts	(62,678,000)	(28,430,000)	(44,809,000)
Loss arising from ineffective portion of commodity contracts	(1,369,000)	(1,585,000)	(2,717,000)
Total impact on purchased gas cost	(64,047,000)	(30,015,000)	(47,526,000)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,009,000)	(2,455,000)	(2,678,000)
Gain On Unwinding Of Treasury Lock Reclassified From Accumulated Oci To Miscellaneous Income		27,803,000	
Total Impact from Cash Flow Hedges	(66,056,000)	(4,667,000)	(50,204,000)
Other Comprehensive Income [Abstract]			
Treasury lock agreements fair value	(11,458,000)	(12,720,000)	
Forward commodity contracts fair value	(30,366,000)	(12,096,000)	
Treasury lock agreements	1,342,000	(15,969,000)	
Forward commodity contracts	38,232,000	17,344,000	
Total other comprehensive income (loss) from hedging, net of tax	(2,250,000)	(23,441,000)	
Expected Earnings [Line Items]			
Treasury Lock Gain Loss Reclassified To Earnings	9,727,000		
Total Hedge Gain Loss Reclassified To Earnings	732,000		
Commodity Contract Gain Loss Reclassified To Earnings	(8,995,000)		
Natural Gas Inventory [Abstract]			
Inventory Write-down	1,700,000		
Summary Of Derivative Instruments Abstract			
Minimum Length Of Time Hedged In Cash Flow Hedge	one		
Maximum Length Of Time Hedged In Cash Flow Hedge	63 months		
Net Open Positions	0.4		
Gain Loss On Hedge Ineffectiveness	23,100,000	24,800,000	51,800,000

Regulated Segments Effective Income Tax Rate Reconciliation At Federal Statutory Income Tax Rate	37.00%		
Nonregulated Segment Effective Income Tax Rate Reconciliation At Federal Statutory Income Tax Rate	39.00%		
Gain Loss On Derivative Instruments Not Designated Hedges Net Pretax	(2,500,000)	(1,400,000)	15,400,000
Disposal Group, Including Discontinued Operation, Derivative Liabilities, Current	300,000	1,300,000	
Disposal Group, Including Discontinued Operation, Derivative Assets, Current	100,000		
Gain (Loss) on Treasury Lock Agreements Settlements, Net of Tax		12,600,000	
One Year From Balance Sheet Date Member			
Expected Earnings [Line Items]			
Treasury Lock Gain Loss Reclassified To Earnings	(1,276,000)		
Total Hedge Gain Loss Reclassified To Earnings	(8,447,000)		
Commodity Contract Gain Loss Reclassified To Earnings	(7,171,000)		
More Than One And Within Two Years From Balance Sheet Date Member			
Expected Earnings [Line Items]			
Treasury Lock Gain Loss Reclassified To Earnings	(1,276,000)		
Total Hedge Gain Loss Reclassified To Earnings	(3,184,000)		
Commodity Contract Gain Loss Reclassified To Earnings	(1,908,000)		
More Than Two And Within Three Years From Balance Sheet Date Member			
Expected Earnings [Line Items]			
Treasury Lock Gain Loss Reclassified To Earnings	606,000		
Total Hedge Gain Loss Reclassified To Earnings	616,000		
Commodity Contract Gain Loss Reclassified To Earnings	10,000		
More Than Three And Within Four Years From Balance Sheet Date Member			
Expected Earnings [Line Items]			
Treasury Lock Gain Loss Reclassified To Earnings	776,000		
Total Hedge Gain Loss Reclassified To Earnings	822,000		
Commodity Contract Gain Loss Reclassified To Earnings	46,000		
More Than Four And Within Five Years From Balance Sheet Date Member			
Expected Earnings [Line Items]			
Treasury Lock Gain Loss Reclassified To Earnings	675,000		
Total Hedge Gain Loss Reclassified To Earnings	703,000		
Commodity Contract Gain Loss Reclassified To Earnings	28,000		
More Than Five Years From Balance Sheet Date And Thereafter Member			
Expected Earnings [Line Items]			
Treasury Lock Gain Loss Reclassified To Earnings	10,222,000		
Total Hedge Gain Loss Reclassified To Earnings	10,222,000		

Commodity Contract Gain Loss Reclassified To Earnings	0	
Designated As Hedging Instrument [Member]		
Derivatives Fair Value [Line Items]		
Net assets liabilities	(92,602,000)	(83,730,000)
Designated As Hedging Instrument [Member] | Other Current Assets [Member]		
Derivatives Fair Value [Line Items]		
Derivative Assets Current	19,301,000	22,396,000
Designated As Hedging Instrument [Member] | Deferred Charges And Other Assets [Member]		
Derivatives Fair Value [Line Items]		
Derivative Assets Noncurrent	1,923,000	174,000
Designated As Hedging Instrument [Member] | Other Current Liabilities [Member]		
Derivatives Fair Value [Line Items]		
Derivative Liabilities Current	(108,827,000)	(31,064,000)
Designated As Hedging Instrument [Member] | Deferred Credits And Other Liabilities [Member]		
Derivatives Fair Value [Line Items]		
Derivative Liabilities Noncurrent	(4,999,000)	(75,236,000)
Nondesignated [Member]		
Derivatives Fair Value [Line Items]		
Derivative Liabilities Noncurrent	(67,062,000)	
Other Derivatives Not Designated As Hedging Instruments At Fair Value Net	1,219,000	(20,597,000)
Nondesignated [Member] | Other Current Assets [Member]		
Derivatives Fair Value [Line Items]		
Derivative Assets Current	105,475,000	68,553,000
Nondesignated [Member] | Deferred Charges And Other Assets [Member]		
Derivatives Fair Value [Line Items]		
Derivative Assets Noncurrent	63,215,000	23,377,000
Nondesignated [Member] | Other Current Liabilities [Member]		
Derivatives Fair Value [Line Items]		
Derivative Liabilities Current	(100,409,000)	(87,121,000)
Nondesignated [Member] | Deferred Credits And Other Liabilities [Member]		
Derivatives Fair Value [Line Items]		
Derivative Liabilities Noncurrent		(25,406,000)
Natural Gas Distribution Segment [Member]		
Commodity Contract Outstanding Volumes [Line Items]		
Fair Value	0	
Cash Flow	0	
Not designated	24,185	
Total Commodity Contracts Outstanding	24,185	

Derivatives Fair Value [Line Items]			
Derivative Assets Current	6,934,000	843,000	
Derivative Assets Noncurrent	2,283,000	998,000	
Derivative Liabilities Current	85,366,000	11,916,000	
Derivative Liabilities Noncurrent	0	67,862,000	
Total Financial Instruments	(76,260,000)	(79,277,000)	
Cash Flow Hedge [Line Items]			
Loss reclassified from AOCI into purchased gas for effective portion of commodity contracts	0	0	0
Loss arising from ineffective portion of commodity contracts	0	0	0
Total impact on purchased gas cost	0	0	0
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,009,000)	(2,455,000)	(2,678,000)
Gain On Unwinding Of Treasury Lock Reclassified From Accumulated Oci To Miscellaneous Income		21,803,000	
Total Impact from Cash Flow Hedges	(2,009,000)	19,348,000	(2,678,000)
Natural Gas Distribution Segment [Member] | Designated As Hedging Instrument [Member]			
Derivatives Fair Value [Line Items]			
Net assets liabilities	(85,040,000)	(67,527,000)	
Natural Gas Distribution Segment [Member] | Designated As Hedging Instrument [Member] | Other Current Assets [Member]			
Derivatives Fair Value [Line Items]			
Derivative Assets Current	0	0	
Natural Gas Distribution Segment [Member] | Designated As Hedging Instrument [Member] | Deferred Charges And Other Assets [Member]			
Derivatives Fair Value [Line Items]			
Derivative Assets Noncurrent	0	0	
Natural Gas Distribution Segment [Member] | Designated As Hedging Instrument [Member] | Other Current Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Current	(85,040,000)	0	
Natural Gas Distribution Segment [Member] | Designated As Hedging Instrument [Member] | Deferred Credits And Other Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Noncurrent	0	(67,527,000)	
Natural Gas Distribution Segment [Member] | Nondesignated [Member]			
Derivatives Fair Value [Line Items]			
Other Derivatives Not Designated As Hedging Instruments At Fair Value Net	8,780,000	(11,750,000)	
Natural Gas Distribution Segment [Member] | Nondesignated [Member] | Other Current Assets [Member]			
Derivatives Fair Value [Line Items]			

Derivative Assets Current	7,082,000	843,000	
Natural Gas Distribution Segment [Member] | Nondesignated [Member] | Deferred Charges And Other Assets [Member]			
Derivatives Fair Value [Line Items]			
Derivative Assets Noncurrent	2,283,000	998,000	
Natural Gas Distribution Segment [Member] | Nondesignated [Member] | Other Current Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Current	(585,000)	(13,256,000)	
Natural Gas Distribution Segment [Member] | Nondesignated [Member] | Deferred Credits And Other Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Noncurrent	0	(335,000)	
Nonregulated Segment [Member]			
Commodity Contract Outstanding Volumes [Line Items]			
Fair Value	(22,650)		
Cash Flow	35,300		
Not designated	49,155		
Total Commodity Contracts Outstanding	61,805		
Derivatives Fair Value [Line Items]			
Derivative Assets Current	17,773,000	17,501,000	
Derivative Assets Noncurrent	0	0	
Derivative Liabilities Current	15,000	3,537,000	
Derivative Liabilities Noncurrent	9,206,000	10,227,000	
Total Financial Instruments	(15,123,000)	(25,050,000)	
Cash Flow Hedge [Line Items]			
Loss reclassified from AOCI into purchased gas for effective portion of commodity contracts	(62,678,000)	(28,430,000)	(44,809,000)
Loss arising from ineffective portion of commodity contracts	(1,369,000)	(1,585,000)	(2,717,000)
Total impact on purchased gas cost	(64,047,000)	(30,015,000)	(47,526,000)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	0	0	0
Gain On Unwinding Of Treasury Lock Reclassified From Accumulated Oci To Miscellaneous Income		0	
Total Impact from Cash Flow Hedges	(64,047,000)	(30,015,000)	(47,526,000)
Nonregulated Segment [Member] | Designated As Hedging Instrument [Member]			
Derivatives Fair Value [Line Items]			
Net assets liabilities	(7,562,000)	(16,203,000)	
Nonregulated Segment [Member] | Designated As Hedging Instrument [Member] | Other Current Assets [Member]			
Derivatives Fair Value [Line Items]			
Derivative Assets Current	19,301,000	22,396,000	
Nonregulated Segment [Member] | Designated As Hedging Instrument [Member] | Deferred Charges And Other Assets [Member]			

Derivatives Fair Value [Line Items]			
Derivative Assets Noncurrent	1,923,000	174,000	
Nonregulated Segment [Member] | Designated As Hedging Instrument [Member] | Other Current Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Current	(23,787,000)	(31,064,000)	
Nonregulated Segment [Member] | Designated As Hedging Instrument [Member] | Deferred Credits And Other Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Noncurrent	(4,999,000)	(7,709,000)	
Nonregulated Segment [Member] | Nondesignated [Member]			
Derivatives Fair Value [Line Items]			
Other Derivatives Not Designated As Hedging Instruments At Fair Value Net	(7,561,000)	(8,847,000)	
Nonregulated Segment [Member] | Nondesignated [Member] | Other Current Assets [Member]			
Derivatives Fair Value [Line Items]			
Derivative Assets Current	98,393,000	67,710,000	
Nonregulated Segment [Member] | Nondesignated [Member] | Deferred Charges And Other Assets [Member]			
Derivatives Fair Value [Line Items]			
Derivative Assets Noncurrent	60,932,000	22,379,000	
Nonregulated Segment [Member] | Nondesignated [Member] | Other Current Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Current	(99,824,000)	(73,865,000)	
Nonregulated Segment [Member] | Nondesignated [Member] | Deferred Credits And Other Liabilities [Member]			
Derivatives Fair Value [Line Items]			
Derivative Liabilities Noncurrent	(67,062,000)	(25,071,000)	
Regulated Transmission and Storage Segment [Member]			
Derivatives Fair Value [Line Items]			
Derivative Assets Current	0	0	
Derivative Assets Noncurrent	0	0	
Derivative Liabilities Current	0	0	
Derivative Liabilities Noncurrent	0	0	
Cash Flow Hedge [Line Items]			
Loss reclassified from AOCI into purchased gas for effective portion of commodity contracts	0	0	0
Loss arising from ineffective portion of commodity contracts	0	0	0
Total impact on purchased gas cost	0	0	0
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	0	0	0
Gain On Unwinding Of Treasury Lock Reclassified From Accumulated Oci To Miscellaneous Income		6,000,000	

Total Impact from Cash Flow Hedges	$ 0	$ 6,000,000	$ 0

Segment Reporting (Table)	12 Months Ended Sep. 30, 2012

Segment Information Tables [Abstract]

Schedule of segment reporting income statement, by segment

	Year Ended September 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$ 2,144,376	$ 92,604	$ 1,201,503	$ -	$ 3,438,483
Intersegment revenues	954	154,747	149,800	(305,501)	-
	2,145,330	247,351	1,351,303	(305,501)	3,438,483
Purchased gas cost	1,122,587	-	1,296,179	(304,022)	2,114,744
Gross profit	1,022,743	247,351	55,124	(1,479)	1,323,739
Operating expenses					
Operation and maintenance	353,879	71,521	29,697	(1,484)	453,613
Depreciation and amortization	202,026	31,438	4,061	-	237,525
Taxes, other than income	162,377	15,568	3,128	-	181,073
Asset impairments	-	-	5,288	-	5,288
Total operating expenses	718,282	118,527	42,174	(1,484)	877,499
Operating income	304,461	128,824	12,950	5	446,240
Miscellaneous income (expense)	(12,657)	(1,051)	1,035	(1,971)	(14,644)
Interest charges	110,642	29,414	3,084	(1,966)	141,174
Income from continuing operations before income taxes	181,162	98,359	10,901	-	290,422
Income tax expense	57,314	35,300	5,612	-	98,226
Income from continuing operations	123,848	63,059	5,289	-	192,196
Income from discontinued operations, net of tax	18,172	-	-	-	18,172
Gain on sale of discontinued operations, net of tax	6,349	-	-	-	6,349
Net income	$ 148,369	$ 63,059	$ 5,289	$ -	$ 216,717
Capital expenditures	$ 546,818	$ 175,768	$ 10,272	$ -	$ 732,858

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

	Year Ended September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$ 2,782,993	$ 97,023	$ 1,781,044	$ -	$ 4,661,060

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

Revenue from External Customers by Products and Services

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

Schedule of segment reporting balance sheet information, by segment

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

Deferred income taxes	789,288	220,647	5,148	-	1,015,083
Noncurrent liabilities from risk management activities	-	-	9,206	-	9,206
Regulatory cost of removal obligation	381,164	-	-	-	381,164
Deferred credits and other liabilities	495,530	2,142	1,048	-	498,720
	$ 7,375,704	$ 1,148,006	$ 576,978	$ (1,605,013)	$ 7,495,675

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

Leases (Details) (USD $)	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Capital Leases Of Lessee Abstract			
Capital Leased Assets Gross	$ 1,300,000	$ 1,300,000	
Capital Leases Accumulated Depreciation	900,000	900,000	
Operating Leases Future Minimum Payments Due Current	17,571,000		
Operating Leases Future Minimum Payments Due In Two Years	17,215,000		
Operating Leases Future Minimum Payments Due In Three Years	15,940,000		
Operating Leases Future Minimum Payments Due In Four Years	15,036,000		
Operating Leases Future Minimum Payments Due In Five Years	14,597,000		
Operating Leases Future Minimum Payments Due Thereafter	100,632,000		
Total Operating Lease Payments	180,991,000		
Capital Leases Future Minimum Payments Due Current	186,000		
Capital Leases Future Minimum Payments Due In Two Years	186,000		
Capital Leases Future Minimum Payments Due In Three Years	186,000		
Capital Leases Future Minimum Payments Due In Four Years	186,000		
Capital Leases Future Minimum Payments Due In Five Years	186,000		
Capital Leases Future Minimum Payments Due Thereafter	78,000		
Total Capital Minimum Lease Payments	1,008,000		
Capital Lease, Interest Included In Lease Payments	286,000		
Present Value Of Net Minimum Lease Payments	722,000		
Lease and Rental Expense	33,600,000	35,500,000	36,700,000
Capital Leases Of Lessor Abstract			
Capital Leases Future Minimum Payments Receivable Current	$ 168,000	$ 2,013,000	

Fair Value Measurements (Details) (USD $)	12 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Natural gas distribution segment	$ 9,365,000	$ 1,841,000
Nonregulated Segement Derivative Assets	17,773,000	17,502,000
Total financial instruments	27,138,000	19,343,000
Hedged portion of gas stored underground	67,192,000	47,940,000
Available For Sale Securities, Registered Investment Companies	40,212,000	36,444,000
Fair value	64,398,000	52,633,000
Total assets	158,728,000	119,916,000
Natural gas distribution segment	85,625,000	81,118,000
Nonregulated Segement Derivative Liabilities	9,221,000	13,765,000
Total liabilities	94,846,000	94,883,000
Fair Value [Abstract]		
Cash Collateral Right To Reclaim Cash	23,700,000	28,800,000
Debt Instrument Fair Value	2,426,434,000	
Cash Held In Margin Accounts Offset Current Risk Management Liabilities	5,900,000	12,400,000
Cash Held In Margin Accounts Classified Current Risk Management Asset	17,800,000	16,400,000
Other Matters [Abstract]		
Asset Impairment Charges Park City	5,300,000	11,000,000
Asset Impairment Charges Fort Necessity		19,300,000
Nonrecurring fair value measurement	500,000	
Fair Value Inputs Level 1 [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Natural gas distribution segment	0	0
Nonregulated Segement Derivative Assets	714,000	8,502,000
Total financial instruments	714,000	8,502,000
Hedged portion of gas stored underground	67,192,000	47,940,000
Available-for-sale Securities, Money Market Funds	0	0
Available For Sale Securities, Registered Investment Companies	40,212,000	36,444,000
Available For Sale Securities, Bonds	0	
Fair value	40,212,000	36,444,000
Total assets	108,118,000	92,886,000
Natural gas distribution segment	0	0
Nonregulated Segement Derivative Liabilities	4,563,000	9,324,000
Total liabilities	4,563,000	9,324,000
Fair Value Inputs Level 2 [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Natural gas distribution segment	9,365,000	1,841,000
Nonregulated Segement Derivative Assets	179,835,000	104,156,000
Total financial instruments	189,200,000	105,997,000

Hedged portion of gas stored underground	0	0
Available-for-sale Securities, Money Market Funds	1,634,000	1,823,000
Available For Sale Securities, Registered Investment Companies	0	0
Available For Sale Securities, Bonds	22,552,000	14,366,000
Fair value	24,186,000	16,189,000
Total assets	213,386,000	122,186,000
Natural gas distribution segment	85,625,000	81,118,000
Nonregulated Segement Derivative Liabilities	191,109,000	128,384,000
Total liabilities	276,734,000	209,502,000
Fair Value Inputs Level 3 [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Natural gas distribution segment	0	0
Nonregulated Segement Derivative Assets	0	0
Total financial instruments	0	0
Hedged portion of gas stored underground	0	0
Available-for-sale Securities, Money Market Funds	0	0
Available For Sale Securities, Registered Investment Companies	0	0
Available For Sale Securities, Bonds	0	
Fair value	0	0
Total assets	0	0
Natural gas distribution segment	0	0
Nonregulated Segement Derivative Liabilities	0	0
Total liabilities	0	0
Netting And Collateral [Member]		
Fair Value Assets And Liabilities Measured On Recurring And Nonrecurring Basis [Line Items]		
Natural gas distribution segment	0	0
Nonregulated Segement Derivative Assets	(162,776,000)	(95,156,000)
Total financial instruments	(162,776,000)	(95,156,000)
Hedged portion of gas stored underground	0	0
Available-for-sale Securities, Money Market Funds	0	0
Available For Sale Securities, Registered Investment Companies	0	0
Available For Sale Securities, Bonds	0	
Fair value	0	0
Total assets	(162,776,000)	(95,156,000)
Natural gas distribution segment	0	0
Nonregulated Segement Derivative Liabilities	(186,451,000)	(123,943,000)
Total liabilities	$ (186,451,000)	$ (123,943,000)

Concentration of Credit Risk (Table)	**12 Months Ended Sep. 30, 2012**
Concentration of Credit Risk Tables [Abstract]	
Schedules of Concentration of Risk, by Risk Factor	

	September 30, 2012	**September 30, 2011**
Investment grade	60%	54%
Non-investment grade	40%	46%
Total	100%	100%

Fair Value, Concentration of Risk

	Natural Gas Distribution Segment [1]	**Nonregulated Segment**	**Consolidated**
		(In thousands)	
Investment grade counterparties	$ -	$ 4	$ 4
Non-investment grade counterparties	-	-	-
	$ -	$ 4	$ 4

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

Summary of Signficant Accounting Policies (Table)	12 Months Ended Sep. 30, 2012
Accumulated Other Comprehensive Income Loss Table [Abstract]	
Accumulated other comprehensive income/loss table	

	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)

Regulatory Assets And Liabilities Table [Abstract]	
Regulatory assets and liabilities table	

	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

Segment Reporting (Details) (USD $) In Thousands, unless otherwise specified	3 Months Ended								12 Months Ended			
	Sep. 30, 2012	Jun. 30, 2012	Mar. 31, 2012	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010	Sep. 30, 2009
Gas Sales Revenue [Abstract]												
Residential									$ 1,351,479	$ 1,535,887	$ 1,751,186	
Commercial									587,651	685,380	775,714	
Industrial									71,960	96,636	101,814	
Public authority and other									54,334	68,676	69,944	
Total gas sales revenue									2,065,424	2,386,579	2,698,658	
Transportation revenues									53,924	57,331	56,539	
Other gas revenues									25,028	25,871	27,796	
Segment Reporting Information Profit Loss [Abstract]												
Revenues from external customers									3,438,483	4,286,435	4,661,060	
Intersegment revenues									0	0	0	
Operating revenues	552,566	576,414	1,225,509	1,083,994	779,667	833,168	1,556,374	1,117,226	3,438,483	4,286,435	4,661,060	
Purchased gas cost									2,114,744	2,985,615	3,346,924	
Gross profit	249,389	293,171	425,787	355,392	237,160	261,612	444,466	357,582	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	0	
Total operating expenses									877,499	874,834	850,303	
Operating income	22,791	81,546	202,432	139,471	39,195	31,394	204,624	150,773	446,240	425,986	463,833	
Miscellaneous income (expense)									(14,644)	21,184	(591)	
Interest charges									141,174	150,763	154,188	
Income (loss) before income taxes									290,422	296,407	309,054	
Income tax expense (benefit)									98,226	106,819	119,203	
Income (loss) from continuing operations	(286)	28,014	102,084	62,384	237	(3,150)	124,293	68,208	192,196	189,588	189,851	
Income (loss) from discontinued operations	1,904	3,118	7,027	6,123	1,724	2,584	7,916	5,789	18,172	18,013	15,988	
Gain on sale of discountinued operations	6,349	0	0	0					6,349	0	0	
Net income (loss)	7,967	31,132	109,111	68,507	1,961	(566)	132,209	73,997	216,717	207,601	205,839	
Capital expenditures									732,858	622,965	542,636	
ASSETS												
Net property, plant and equipment	5,475,604				5,147,918				5,475,604	5,147,918		
Investment in subsidaries	0				0				0	0		
Current assets												
Cash and cash equivalents	64,239				131,419				64,239	131,419	131,952	111,203
Assets from risk management activities current	24,707				18,344				24,707	18,344		
Other current assets	739,016				861,190				739,016	861,190		
Intercompany receivables	0				0				0	0		
Total current assets	827,962				1,010,953				827,962	1,010,953		
Intangible assets	164				207				164	207		
Goodwill	740,683				740,000				740,683	740,000		
Assets from risk management activities noncurrent	2,283				998				2,283	998		
Deferred charges and other assets	448,979				382,795				448,979	382,795		
Total Assets	7,495,675				7,282,871				7,495,675	7,282,871		

CAPITALIZATION AND LIABILITIES												
Shareholders' equity	2,359,243				2,255,421				2,359,243	2,255,421	2,178,348	2,176,761
Long-term debt	1,956,305				2,206,117				1,956,305	2,206,117		
Total capitalization	4,315,548				4,461,538				4,315,548	4,461,538		
Current liabilities												
Current maturities of long-term debt	131				2,434				131	2,434		
Short-term debt	570,929				206,396				570,929	206,396		
Liabilitied from risk management activities current	85,381				15,453				85,381	15,453		
Other current liabilities	619,513				643,315				619,513	643,315		
Intercompany payables	0				0				0	0		
Total current liabilities	1,275,954				867,598				1,275,954	867,598		
Deferred income taxes	1,015,083				960,093				1,015,083	960,093		
Liabilities from risk management activities noncurrent	9,206				78,089				9,206	78,089		
Deferred credits and other liabilities	498,720				486,606				498,720	486,606		
Total Equity and Liabilities	7,495,675				7,282,871				7,495,675	7,282,871		
Natural Gas Distribution Segment [Member]												
Segment Reporting Information Profit Loss [Abstract]												
Revenues from external customers									2,144,376	2,469,781	2,782,993	
Intersegment revenues									954	883	870	
Operating revenues	282,516	315,634	871,067	676,113	334,363	396,584	1,052,291	687,426	2,145,330	2,470,664	2,783,863	
Purchased gas cost									1,122,587	1,452,721	1,785,221	
Gross profit									1,022,743	1,017,943	998,642	
Operating expenses												
Operation and maintenance									353,879	341,758	349,465	
Depreciation and amortization									202,026	193,642	182,097	
Taxes, other than income									162,377	160,455	170,229	
Asset impairments									0	0		
Total operating expenses									718,282	695,855	701,791	
Operating income									304,461	322,088	296,851	
Miscellaneous income (expense)									(12,657)	16,242	1,132	
Interest charges									110,642	115,740	118,147	
Income (loss) before income taxes									181,162	222,590	179,836	
Income tax expense (benefit)									57,314	77,885	69,875	
Income (loss) from continuing operations									123,848	144,705	109,961	
Income (loss) from discontinued operations									18,172	18,013	15,988	
Gain on sale of discountinued operations									6,349			
Net income (loss)									148,369	162,718	125,949	
Capital expenditures									546,818	496,899	437,815	
ASSETS												
Net property, plant and equipment	4,432,017				4,248,198				4,432,017	4,248,198		
Investment in subsidaries	747,496				670,993				747,496	670,993		
Current assets												
Cash and cash equivalents	12,787				24,646				12,787	24,646		
Assets from risk management activities current	6,934				843				6,934	843		
Other current assets	546,187				655,716				546,187	655,716		
Intercompany receivables	636,557				569,898				636,557	569,898		
Total current assets	1,202,465				1,251,103				1,202,465	1,251,103		

Intangible assets	0				0				0	0	
Goodwill	573,550				572,908				573,550	572,908	
Assets from risk management activities noncurrent	2,283				998				2,283	998	
Deferred charges and other assets	417,893				353,960				417,893	353,960	
Total Assets	7,375,704				7,098,160				7,375,704	7,098,160	
CAPITALIZATION AND LIABILITIES											
Shareholders' equity	2,359,243				2,255,421				2,359,243	2,255,421	
Long-term debt	1,956,305				2,205,986				1,956,305	2,205,986	
Total capitalization	4,315,548				4,461,407				4,315,548	4,461,407	
Current liabilities											
Current maturities of long-term debt	0				2,303				0	2,303	
Short-term debt	782,719				387,691				782,719	387,691	
Liabilitied from risk management activities current	85,366				11,916				85,366	11,916	
Other current liabilities	526,089				474,783				526,089	474,783	
Intercompany payables	0				0				0	0	
Total current liabilities	1,394,174				876,693				1,394,174	876,693	
Deferred income taxes	789,288				789,649				789,288	789,649	
Liabilities from risk management activities noncurrent	0				67,862				0	67,862	
Regulatory cost of removal obligation	381,164				428,947				381,164	428,947	
Deferred credits and other liabilities	495,530				473,602				495,530	473,602	
Total Equity and Liabilities	7,375,704				7,098,160				7,375,704	7,098,160	
Regulated Transmission and Storage Segment [Member]											
Segment Reporting Information Profit Loss [Abstract]											
Revenues from external customers									92,604	87,141	97,023
Intersegment revenues									154,747	132,232	105,990
Operating revenues	65,482	67,073	58,037	56,759	61,820	53,570	54,976	49,007	247,351	219,373	203,013
Purchased gas cost									0	0	0
Gross profit									247,351	219,373	203,013
Operating expenses											
Operation and maintenance									71,521	70,401	72,249
Depreciation and amortization									31,438	25,997	21,368
Taxes, other than income									15,568	14,700	12,358
Asset impairments									0	0	
Total operating expenses									118,527	111,098	105,975
Operating income									128,824	108,275	97,038
Miscellaneous income (expense)									(1,051)	4,715	135
Interest charges									29,414	31,432	31,174
Income (loss) before income taxes									98,359	81,558	65,999
Income tax expense (benefit)									35,300	29,143	24,513
Income (loss) from continuing operations									63,059	52,415	41,486
Income (loss) from discontinued operations									0	0	0
Gain on sale of discontinued operations									0		
Net income (loss)									63,059	52,415	41,486
Capital expenditures									175,768	118,452	95,835
ASSETS											

Net property, plant and equipment	979,443				838,302				979,443	838,302	
Investment in subsidaries	0				0				0	0	
Current assets											
Cash and cash equivalents	0				0				0	0	
Assets from risk management activities current	0				0				0	0	
Other current assets	11,788				15,413				11,788	15,413	
Intercompany receivables	0				0				0	0	
Total current assets	11,788				15,413				11,788	15,413	
Intangible assets	0				0				0	0	
Goodwill	132,422				132,381				132,422	132,381	
Assets from risk management activities noncurrent	0				0				0	0	
Deferred charges and other assets	24,353				18,028				24,353	18,028	
Total Assets	1,148,006				1,004,124				1,148,006	1,004,124	
CAPITALIZATION AND LIABILITIES											
Shareholders' equity	328,161				265,102				328,161	265,102	
Long-term debt	0				0				0	0	
Total capitalization	328,161				265,102				328,161	265,102	
Current liabilities											
Current maturities of long-term debt	0				0				0	0	
Short-term debt	0				0				0	0	
Liabilitied from risk management activities current	0				0				0	0	
Other current liabilities	12,478				10,369				12,478	10,369	
Intercompany payables	584,578				543,084				584,578	543,084	
Total current liabilities	597,056				553,453				597,056	553,453	
Deferred income taxes	220,647				173,351				220,647	173,351	
Liabilities from risk management activities noncurrent	0				0				0	0	
Regulatory cost of removal obligation	0				0				0	0	
Deferred credits and other liabilities	2,142				12,218				2,142	12,218	
Total Equity and Liabilities	1,148,006				1,004,124				1,148,006	1,004,124	
Nonregulated Segment [Member]											
Segment Reporting Information Profit Loss [Abstract]											
Revenues from external customers									1,201,503	1,729,513	1,781,044
Intersegment revenues									149,800	295,380	365,614
Operating revenues	280,114	256,250	370,763	444,176	474,437	491,285	583,531	475,640	1,351,303	2,024,893	2,146,658
Purchased gas cost									1,296,179	1,959,893	2,032,567
Gross profit									55,124	65,000	114,091
Operating expenses											
Operation and maintenance									29,697	32,308	34,517
Depreciation and amortization									4,061	4,193	5,074
Taxes, other than income									3,128	2,612	4,556
Asset impairments									5,288	30,270	
Total operating expenses									42,174	69,383	44,147
Operating income									12,950	(4,383)	69,944
Miscellaneous income (expense)									1,035	657	3,859
Interest charges									3,084	4,015	10,584
Income (loss) before income taxes									10,901	(7,741)	63,219
Income tax expense (benefit)									5,612	(209)	24,815

Income (loss) from continuing operations									5,289	(7,532)	38,404
Income (loss) from discontinued operations									0	0	0
Gain on sale of discountinued operations									0		
Net income (loss)									5,289	(7,532)	38,404
Capital expenditures									10,272	7,614	8,986
ASSETS											
Net property, plant and equipment	64,144				61,418				64,144	61,418	
Investment in subsidaries	(2,096)				(2,096)				(2,096)	(2,096)	
Current assets											
Cash and cash equivalents	51,452				106,773				51,452	106,773	
Assets from risk management activities current	17,773				17,501				17,773	17,501	
Other current assets	404,097				386,215				404,097	386,215	
Intercompany receivables	0				0				0	0	
Total current assets	473,322				510,489				473,322	510,489	
Intangible assets	164				207				164	207	
Goodwill	34,711				34,711				34,711	34,711	
Assets from risk management activities noncurrent	0				0				0	0	
Deferred charges and other assets	6,733				10,807				6,733	10,807	
Total Assets	576,978				615,536				576,978	615,536	
CAPITALIZATION AND LIABILITIES											
Shareholders' equity	419,335				405,891				419,335	405,891	
Long-term debt	0				131				0	131	
Total capitalization	419,335				406,022				419,335	406,022	
Current liabilities											
Current maturities of long-term debt	131				131				131	131	
Short-term debt	0				0				0	0	
Liabilitied from risk management activities current	15				3,537				15	3,537	
Other current liabilities	90,116				170,926				90,116	170,926	
Intercompany payables	51,979				26,814				51,979	26,814	
Total current liabilities	142,241				201,408				142,241	201,408	
Deferred income taxes	5,148				(2,907)				5,148	(2,907)	
Liabilities from risk management activities noncurrent	9,206				10,227				9,206	10,227	
Regulatory cost of removal obligation	0				0				0	0	
Deferred credits and other liabilities	1,048				786				1,048	786	
Total Equity and Liabilities	576,978				615,536				576,978	615,536	
Intersegment Elimination [Member]											
Segment Reporting Information Profit Loss [Abstract]											
Revenues from external customers									0	0	0
Intersegment revenues									(305,501)	(428,495)	(472,474)
Operating revenues	(75,546)	(62,543)	(74,358)	(93,054)	(90,953)	(108,271)	(134,424)	(94,847)	(305,501)	(428,495)	(472,474)
Purchased gas cost									(304,022)	(426,999)	(470,864)
Gross profit									(1,479)	(1,496)	(1,610)
Operating expenses											
Operation and maintenance									(1,484)	(1,502)	(1,610)
Depreciation and amortization									0	0	0
Taxes, other than income									0	0	0

Asset impairments			0	0	
Total operating expenses			(1,484)	(1,502)	(1,610)
Operating income			5	6	0
Miscellaneous income (expense)			(1,971)	(430)	(5,717)
Interest charges			(1,966)	(424)	(5,717)
Income (loss) before income taxes			0	0	0
Income tax expense (benefit)			0	0	0
Income (loss) from continuing operations			0	0	0
Income (loss) from discontinued operations			0	0	0
Gain on sale of discountinued operations			0		
Net income (loss)			0	0	0
Capital expenditures			0	0	0
ASSETS					
Net property, plant and equipment	0	0	0	0	
Investment in subsidaries	(745,400)	(668,897)	(745,400)	(668,897)	
Current assets					
Cash and cash equivalents	0	0	0	0	
Assets from risk management activities current	0	0	0	0	
Other current assets	(223,056)	(196,154)	(223,056)	(196,154)	
Intercompany receivables	(636,557)	(569,898)	(636,557)	(569,898)	
Total current assets	(859,613)	(766,052)	(859,613)	(766,052)	
Intangible assets	0	0	0	0	
Goodwill	0	0	0	0	
Assets from risk management activities noncurrent	0	0	0	0	
Deferred charges and other assets	0	0	0	0	
Total Assets	(1,605,013)	(1,434,949)	(1,605,013)	(1,434,949)	
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	(747,496)	(670,993)	(747,496)	(670,993)	
Long-term debt	0	0	0	0	
Total capitalization	(747,496)	(670,993)	(747,496)	(670,993)	
Current liabilities					
Current maturities of long-term debt	0	0	0	0	
Short-term debt	(211,790)	(181,295)	(211,790)	(181,295)	
Liabilitied from risk management activities current	0	0	0	0	
Other current liabilities	(9,170)	(12,763)	(9,170)	(12,763)	
Intercompany payables	(636,557)	(569,898)	(636,557)	(569,898)	
Total current liabilities	(857,517)	(763,956)	(857,517)	(763,956)	
Deferred income taxes	0	0	0	0	
Liabilities from risk management activities noncurrent	0	0	0	0	
Regulatory cost of removal obligation	0	0	0	0	
Deferred credits and other liabilities	0	0	0	0	
Total Equity and Liabilities	$ (1,605,013)	$ (1,434,949)	$ (1,605,013)	$ (1,434,949)	

Discontinued Operations (Details) (USD $) In Thousands, unless otherwise specified	3 Months Ended								12 Months Ended		
	Sep. 30, 2012	Jun. 30, 2012	Mar. 31, 2012	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Discontinued Operation Income Loss From Discontinued Operation Disclosures Abstract											
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
Miscellaneous (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 (loss) from discontinued operations	1,904	3,118	7,027	6,123	1,724	2,584	7,916	5,789	18,172	18,013	15,988
Gain on sale of discountinued operations	6,349	0	0	0					6,349	0	0
Net income (loss) from discontinued operations									24,521	18,013	15,988
Disposal Group Including Discontinued Operation Balance Sheet Disclosures Abstract											
Net plant, property & equipment	142,865				127,577				142,865	127,577	
Gas stored underground	4,688				11,931				4,688	11,931	
Other current assets	6,931				786				6,931	786	
Deferred charges and other assets	87				277				87	277	
Assets held for sale	154,571				140,571				154,571	140,571	
Accounts payable	2,114				1,917				2,114	1,917	
Other current liabilities	3,776				4,877				3,776	4,877	
Regulatory cost of removal	3,257				10,498				3,257	10,498	
Deferred credits and other liabilities	2,426				1,153				2,426	1,153	
Liabilities held for sale	11,573				18,445				11,573	18,445	
Other Discontinued Operations Disclosures [Abstract]											
Discontinued Operation, Gain (Loss) from Disposal of									$ 9,868	$ 0	$ 0

Discontinued Operation, before Income Tax	
Disposal Group, Including Discontinued Operation, Description and Timing of Disposal	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.

Concentration of Credit Risk (Details) (USD $) In Thousands, unless otherwise specified	Sep. 30, 2012	Sep. 30, 2011
Nonregulated Segment Credit Exposure [Abstract]		
Investment grade	60.00%	54.00%
Non-investment grade	40.00%	46.00%
Total	100.00%	100.00%
Counterparty Credit Exposure [Line Items]		
Investment grade counterparties	$ 4	
Non-investment grade counterparties	0	
Total	4	
Natural Gas Distribution Segment [Member]		
Counterparty Credit Exposure [Line Items]		
Investment grade counterparties	0	
Non-investment grade counterparties	0	
Total	0	
Nonregulated Segment [Member]		
Counterparty Credit Exposure [Line Items]		
Investment grade counterparties	4	
Non-investment grade counterparties	0	
Total	$ 4	

17. Segment Information

[Segment Reporting Disclosure [Abstract]]

17. Segment Information

12 Months Ended Sep. 30, 2012

17. Segment Information

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

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

We operate the Company through the following three segments:

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

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

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

	Year Ended September 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,144,376	$ 92,604	$ 1,201,503	$ -	$ 3,438,483
Intersegment revenues	954	154,747	149,800	(305,501)	-
	2,145,330	247,351	1,351,303	(305,501)	3,438,483
Purchased gas cost	1,122,587	-	1,296,179	(304,022)	2,114,744
Gross profit	1,022,743	247,351	55,124	(1,479)	1,323,739
Operating expenses					
Operation and maintenance	353,879	71,521	29,697	(1,484)	453,613
Depreciation and amortization	202,026	31,438	4,061	-	237,525
Taxes, other than income	162,377	15,568	3,128	-	181,073
Asset impairments	-	-	5,288	-	5,288
Total operating expenses	718,282	118,527	42,174	(1,484)	877,499
Operating income	304,461	128,824	12,950	5	446,240
Miscellaneous income (expense)	(12,657)	(1,051)	1,035	(1,971)	(14,644)
Interest charges	110,642	29,414	3,084	(1,966)	141,174
Income from continuing operations before income taxes	181,162	98,359	10,901	-	290,422
Income tax expense	57,314	35,300	5,612	-	98,226
Income from continuing operations	123,848	63,059	5,289	-	192,196
Income from discontinued operations, net of tax	18,172	-	-	-	18,172
Gain on sale of discontinued operations, net of tax	6,349	-	-	-	6,349
Net income	$ 148,369	$ 63,059	$ 5,289	$ -	$ 216,717
Capital expenditures	$ 546,818	$ 175,768	$ 10,272	$ -	$ 732,858

	Year Ended September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,469,781	$ 87,141	$ 1,729,513	$ -	$ 4,286,435
Intersegment revenues	883	132,232	295,380	(428,495)	-
	2,470,664	219,373	2,024,893	(428,495)	4,286,435
Purchased gas cost	1,452,721	-	1,959,893	(426,999)	2,985,615
Gross profit	1,017,943	219,373	65,000	(1,496)	1,300,820
Operating expenses					
Operation and maintenance	341,758	70,401	32,308	(1,502)	442,965

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
Depreciation and amortization	193,642	25,997	4,193	-	223,832
Taxes, other than income	160,455	14,700	2,612	-	177,767
Asset impairments	-	-	30,270	-	30,270
Total operating expenses	695,855	111,098	69,383	(1,502)	874,834
Operating income (loss)	322,088	108,275	(4,383)	6	425,986
Miscellaneous income	16,242	4,715	657	(430)	21,184
Interest charges	115,740	31,432	4,015	(424)	150,763
Income (loss) from continuing operations					
before income taxes	222,590	81,558	(7,741)	-	296,407
Income tax expense (benefit)	77,885	29,143	(209)	-	106,819
Income (loss) from continuing					
operations	144,705	52,415	(7,532)	-	189,588
Income from discontinued					
operations, net of tax	18,013	-	-	-	18,013
Net income (loss)	$ 162,718	$ 52,415	$ (7,532)	$ -	$ 207,601
Capital expenditures	$ 496,899	$ 118,452	$ 7,614	$ -	$ 622,965

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

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

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

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

	September 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and					

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

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

Noncurrent liabilities from risk management activities	67,862	-	10,227	-	78,089
Regulatory cost of removal obligation	428,947	-	-	-	428,947
Deferred credits and other liabilities	473,602	12,218	786	-	486,606
	$ 7,098,160	$ 1,004,124	$ 615,536	$ (1,434,949)	$ 7,282,871

Valuation and Qualifying Accounts (Table)	12 Months Ended Sep. 30, 2012
Schedule of Valuation and Qualifying Accounts [Abstract]	
Valuation and Qualifying Accounts	

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

(1) Uncollectible accounts written off.

Earnings Per Share (Table)

12 Months Ended Sep. 30, 2012

Earnings Per Share Table [Abstract]

Earnings per share table

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

Additional dilutive stock options and other shares	1,022	451	570
Diluted weighted average shares outstanding	91,172	90,652	92,422
Income from discontinued operations per share - Diluted	$ 0.27	$ 0.20	$ 0.17
Net income per share - Diluted	$ 2.37	$ 2.27	$ 2.20

Valuation and Qualifying Accounts (Details) (Allowance For Doubtful Accounts Member, USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Allowance For Doubtful Accounts Member			
Valuation And Qualifying Accounts Disclosure [Line Items]			
Balance at beginning of period	$ 7,440	$ 12,701	$ 11,478
Charged to costs & expenses	8,901	2,201	7,694
Charged to other accounts	0	0	0
Valuation Allowances And Reserves Deductions	6,916	7,462	6,471
Balance at end of period	$ 9,425	$ 7,440	$ 12,701

Discontinued Operations (Table)	12 Months Ended Sep. 30, 2012
Discontinued Operations Table [Abstract]	
Discontinued operations income statement detail table	

	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

Assets held for sale table

	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

Goodwill Rollforward (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended Sep. 30, 2012
Goodwill [Line Items]	
Goodwill, Beginning Balance	$ 740,000
Goodwill Other Changes	683
Goodwill, Ending Balance	740,683
Natural Gas Distribution Segment [Member]	
Goodwill [Line Items]	
Goodwill, Beginning Balance	572,908
Goodwill Other Changes	642
Goodwill, Ending Balance	573,550
Regulated Transmission and Storage Segment [Member]	
Goodwill [Line Items]	
Goodwill, Beginning Balance	132,381
Goodwill Other Changes	41
Goodwill, Ending Balance	132,422
Nonregulated Segment [Member]	
Goodwill [Line Items]	
Goodwill, Beginning Balance	34,711
Goodwill Other Changes	0
Goodwill, Ending Balance	$ 34,711

Income Taxes (Details) (USD $)	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Deferred tax assets			
Accruals not currently deductible for tax purposes	$ 7,906,000	$ 10,327,000	
Customer advances	4,721,000	5,271,000	
Nonqualified benefit plans	48,513,000	43,924,000	
Postretirement benefits	62,802,000	62,274,000	
Treasury lock agreements	25,448,000	20,060,000	
Unamortized investment tax credit	14,000	120,000	
Tax net operating loss and credit carryforwards	164,419,000	95,293,000	
Difference between book and tax on mark to market accounting	2,342,000	8,039,000	
Other, net	7,223,000	3,529,000	
Total deferred tax assets	323,388,000	248,837,000	
Deferred tax liabilities			
Difference in net book value and net tax value of assets	1,254,698,000	1,108,063,000	
Pension funding	32,812,000	7,533,000	
Gas Cost Adjustments	21,806,000	13,570,000	
Cost expensed for tax purposes and capitalized for book purposes	2,065,000	3,039,000	
Total deferred tax liabilities	1,311,381,000	1,132,205,000	
Net deferred tax liabilities	(987,993,000)	(883,368,000)	
Operating Loss Carryforwards [Line Items]			
Liabilities associated with uncertain tax positions	1,800,000	6,700,000	
Penalty and interest expenses	10,000	10,000	500,000
Deferred credits for rate regulated entities	140,000	325,000	
Current income taxes			
Federal	631,000	(13,298,000)	(70,884,000)
State	6,888,000	6,841,000	6,849,000
Deferred income taxes			
Federal	103,971,000	107,950,000	172,690,000
State	(13,237,000)	5,498,000	10,831,000
Investment tax credits	(27,000)	(172,000)	(283,000)
Income tax expense (benefit)	98,226,000	106,819,000	119,203,000

Other Information Pertaining to Income Taxes	results for fiscal 2012 were favorably impacted by a state tax benefit of $13.6 million. Due to the completion of the sale of our Missouri, Iowa and Illinois service areas in the fiscal fourth quarter, the Company updated its analysis of the tax rate at which deferred taxes would reverse in the future to reflect the sale of these service areas. The updated analysis supported a reduction in the deferred tax rate which when applied to the balance of taxable income deferred to future periods resulted in a reduction of the Company’s overall deferred tax liability.
Internal Revenue Service IRS [Member]	
Operating Loss Carryforwards [Line Items]	
Amount	143,200,000
Expiration Dates	2029
State And Local Jurisdiction [Member]	
Operating Loss Carryforwards [Line Items]	
Amount	10,600,000
Expiration Dates	between 2016 and 2030
Federal Alternative Minimum Tax Credit Carryforward [Member]	
Other Tax Carryforward [Line Items]	
Amount	10,100,000
State Tax Credit Carryforward [Member]	
Other Tax Carryforward [Line Items]	
Amount	$ 500,000
Expiration dates	2018

Retirement and Post-Retirement Employee Benefit Plans Fair Value Disclosures (Details) (USD $) In Thousands, unless otherwise specified	Sep. 30, 2012	Sep. 30, 2011
Pension Plans Defined Benefit [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	$ 350,296	$ 279,759
Pension Plans Defined Benefit [Member] | Equity Securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	114,799	94,336
Pension Plans Defined Benefit [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	21,010	9,383
Pension Plans Defined Benefit [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	19,984	12,921
Pension Plans Defined Benefit [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	36,714	27,528
Pension Plans Defined Benefit [Member] | Common Collective Trusts [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	52,155	40,096
Pension Plans Defined Benefit [Member] | Mortgage-backed securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	19,509	18,860
Pension Plans Defined Benefit [Member] | U.S. Treasuries [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	8,084	4,993
Pension Plans Defined Benefit [Member] | Corporate Debt Securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	35,960	33,636
Pension Plans Defined Benefit [Member] | Limited Partnership Interest [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	41,926	37,806
Pension Plans Defined Benefit [Member] | Real Estate Investment [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	155	200
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member]		
Schedule of Total Investments at Fair Value [Line Items]		

Total investments at fair value	179,234	139,844
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Equity Securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	114,799	94,336
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	19,984	12,921
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	36,714	27,528
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Common Collective Trusts [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Mortgage-backed securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | U.S. Treasuries [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	7,597	4,946
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Corporate Debt Securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Limited Partnership Interest [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	140	113
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Real Estate Investment [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	170,907	139,715

Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Equity Securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	21,010	9,383
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Common Collective Trusts [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	52,155	40,096
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Mortgage-backed securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	19,509	18,860
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | U.S. Treasuries [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	487	47
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Corporate Debt Securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	35,960	33,636
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Limited Partnership Interest [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	41,786	37,693
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Real Estate Investment [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	155	200
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Equity Securities [Member]		

Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Common Collective Trusts [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Mortgage-backed securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | U.S. Treasuries [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Corporate Debt Securities [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Limited Partnership Interest [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Pension Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Real Estate Investment [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	155	200
Other Postretirement Benefit Plans Defined Benefit [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	78,568	53,065
Other Postretirement Benefit Plans Defined Benefit [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	2,360	1,707

Other Postretirement Benefit Plans Defined Benefit [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	7,756	3,506
Other Postretirement Benefit Plans Defined Benefit [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	68,452	47,852
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	76,208	51,358
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	7,756	3,506
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 1 [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	68,452	47,852
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	2,360	1,707
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	2,360	1,707
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 2 [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0

Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Money Market Funds [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Registered Investment Companies, Domestic [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	0	0
Other Postretirement Benefit Plans Defined Benefit [Member] | Fair Value Inputs Level 3 [Member] | Registered Investment Companies, International [Member]		
Schedule of Total Investments at Fair Value [Line Items]		
Total investments at fair value	$ 0	$ 0

Cash Flow, Supplemental Disclosures (Table)	12 Months Ended Sep. 30, 2012		
Supplemental Cash Flow Disclosure Table [Abstract]			
Supplemental Cash Flow Disclosure Table			

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

1. Nature of Business	12 Months Ended Sep. 30, 2012
Nature Of Operations [Abstract]	
1. Nature Of Business	

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.

Retirement and Post-Retirement Employee Benefit Plans Fair Value of Plan Assets (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended	
	Sep. 30, 2012	Sep. 30, 2011
Pension Plans Defined Benefit [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets at beginning of year	$ 280,204	$ 301,708
Actual return on plan assets	48,656	5,154
Employer contributions	46,534	876
Benefits paid	(24,553)	(27,534)
Divestitures	(7,697)	0
Fair value of plan assets at end of year	343,144	280,204
Other Postretirement Benefit Plans Defined Benefit [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets at beginning of year	53,065	53,033
Actual return on plan assets	12,912	(1,500)
Employer contributions	22,139	11,254
Plan participants' contributions	3,649	2,892
Benefits paid	(13,197)	(13,046)
Subsidy Payments	0	432
Divestitures	(1,496)	0
Fair value of plan assets at end of year	77,072	53,065
Supplemental Executive Retirement Plans, Defined Benefit [Member]		
Defined Benefit Plan Disclosure [Line Items]		
Fair value of plan assets at beginning of year	0	0
Employer contributions	4,638	7,537
Benefits paid	(4,638)	(7,537)
Fair value of plan assets at end of year	$ 0	$ 0

Income Taxes (Table)	12 Months Ended Sep. 30, 2012

Income Taxes Tables [Abstract]

Schedule of Components of Income Tax Expense (Benefit)

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

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

Schedule of Effective Income Tax Rate Reconciliation

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

Schedule of Deferred Tax Assets and Liabilities

	2012	2011
	(In thousands)	
Deferred tax assets:		
Accruals not currently deductible for tax purposes	$ 7,906	$ 10,327
Customer advances	4,721	5,271
Nonqualified benefit plans	48,513	43,924
Postretirement benefits	62,802	62,274
Treasury lock agreements	25,448	20,060
Unamortized investment tax credit	14	120
Tax net operating loss and credit carryforwards	164,419	95,293
Difference between book and tax on mark to market		

accounting	2,342	8,039
Other, net	7,223	3,529
Total deferred tax assets	323,388	248,837
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,254,698)	(1,108,063)
Pension funding	(32,812)	(7,533)
Gas cost adjustments	(21,806)	(13,570)
Cost expensed for tax purposes and capitalized for book purposes	(2,065)	(3,039)
Total deferred tax liabilities	(1,311,381)	(1,132,205)
Net deferred tax liabilities	$ (987,993)	$ (883,368)
Deferred credits for rate regulated entities	$ 140	$ 325

Earnings Per Share (Policy)	12 Months Ended Sep. 30, 2012
Earnings Per Share Policy [Abstract]	
Earnings Per Share Policy Text Block	Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities), we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, granted under the LTIP, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

Summary of Significant Accounting Policies (Policy)	12 Months Ended Sep. 30, 2012
Basis of Presentation and Significant Accounting Policies Disclosure [Abstract]	
Principles of consolidation	***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	***Basis of comparison*** — Certain prior-year amounts have been reclassified to conform with the current year presentation.
Use Of Estimates	***Use of estimates*** — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, unbilled revenues, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligations, impairment of long-lived assets, risk management and trading activities, fair value measurements and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results could differ from those estimates.
Regulation	***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. During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to

this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of September 30, 2012, we had deferred $5.4 million associated with the requirements of this rule.

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

Currently, authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. During the fiscal years ended September 30, 2012, 2011 and 2010, we recognized $0.5 million, $0.5 million and $0.4 million in amortization expense related to these costs.

Revenue recognition

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

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

Gas stored underground

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.

Property Plant And Equipment Policy Text Block

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

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

As of September 30, 2012 and 2011, we recorded asset retirement obligations of $10.5 million and $14.0 million. Additionally, we recorded $4.2 million and $5.4 million of asset retirement costs as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

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

Impairment of long-lived assets

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

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

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.

Derivatives Reporting Of Derivative Activity

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk in our natural gas distribution and nonregulated segments and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses and are discussed in Note 4.

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

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

Financial Instruments Associated with Commodity Price Risk

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

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

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

Gains and losses from hedge ineffectiveness are recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the financial instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity is referred to as timing ineffectiveness. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Our nonregulated segment also utilizes master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. As of September 30, 2012 and 2011, the Company netted $23.7 million and $28.8 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We manage interest rate risk, typically when we plan to issue new long-term debt or to refinance existing long-term debt. Prior to fiscal 2012, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement.

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

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

Fair Value Measurements

Fair Value Measurements – We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices), as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed.

We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

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

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

Level 2 – Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 – Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. As of September 30, 2012 our Master Trust owned one real estate investment that qualifies as a Level 3 fair value measurement. Currently, we have no other assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Pension and other postretirement plans

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Our measurement date is September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

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

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

Income taxes

Income taxes — 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

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.

Contingencies

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.

Fair Value Measurements Available-For-Sale Securities (Details) (USD $) In Thousands, unless otherwise specified	Sep. 30, 2012	Sep. 30, 2011
Schedule Of Available For Sale Securities [Line Items]		
Amortized Cost	$ 55,339	$ 48,558
Gross Unrealized Gain	9,061	4,351
Gross Unrealized Loss	2	276
Fair value	64,398	52,633
Equity Funds, Domestic [Member]		
Schedule Of Available For Sale Securities [Line Items]		
Amortized Cost	25,779	27,748
Gross Unrealized Gain	8,183	4,074
Gross Unrealized Loss	0	0
Fair value	33,962	31,822
Equity Funds, Foreign [Member]		
Schedule Of Available For Sale Securities [Line Items]		
Amortized Cost	5,568	4,597
Gross Unrealized Gain	682	267
Gross Unrealized Loss	0	242
Fair value	6,250	4,622
Money Market Funds [Member]		
Schedule Of Available For Sale Securities [Line Items]		
Amortized Cost	1,634	1,823
Gross Unrealized Gain	0	0
Gross Unrealized Loss	0	0
Fair value	1,634	1,823
Debt Securities [Member]		
Schedule Of Available For Sale Securities [Line Items]		
Amortized Cost	22,358	14,390
Gross Unrealized Gain	196	10
Gross Unrealized Loss	2	34
Fair value	$ 22,552	$ 14,366

Commitments and Contingencies (Table)		12 Months Ended Sep. 30, 2012
Commitments and Contingencies Tables [Abstract]		
Long-term supply contracts purchase commitments table		
	2013	$ 259,235
	2014	74,604
	2015	-
	2016	-
	2017	-
	Thereafter	-
		$ 333,839
Estimated Contractual Demand Fees [Table Text Block]		
	2013	$ 19,456
	2014	10,554
	2015	4,504
	2016	278
	2017	37
	Thereafter	128
		$ 34,957

Nonregulated Credit Risk Policy (Policy)	12 Months Ended Sep. 30, 2012
Provision for Credit Loss Policy [Abstract]	
Provision for credit loss policy	AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements, primarily consisting of letters of credit and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance. AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2012, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty. AEM's estimated credit exposure is monitored in terms of the percentage of its customers, including affiliate customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade.

Segment Reporting (Policy)	12 Months Ended Sep. 30, 2012
Segment Reporting Policy [Abstract]	
Segment Reporting Policy	Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

CONSOLIDATED STATEMENTS OF CASH FLOWS (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Cash Flows From Operating Activities			
Net income (loss)	$ 216,717	$ 207,601	$ 205,839
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	5,288	30,270	0
Gain on sale of discontinued operations	(9,868)	0	0
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) decreased in accounts receivable	32,578	(96)	(40,401)
(Increase) 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 account 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 From Investing Activities			
Capital expenditures	(732,858)	(622,965)	(542,636)
Other, net	(4,625)	(4,421)	(66)
Proceeds from Sale of Productive Assets	128,223	0	0
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	0	394,466	0
Settlement of Treasury lock agreement	0	20,079	0
Unwinding of Treasury lock agreements	0	27,803	0
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)	0	(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 period	131,419	131,952	111,203
Cash and cash equivalents at end of period	$ 64,239	$ 131,419	$ 131,952

Nature of Business (Table)	12 Months Ended Sep. 30, 2012
Schedule of Divisions And Service Areas Table [Abstract]	
Schedule of divisions and service areas	

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

Retirement and Post-Retirement Employee Benefit Plans (Table)	12 Months Ended Sep. 30, 2012
Retirement and PostRetirement Employee Benefit Plans Tables [Abstract]	
Schedule of Net Periodic Benefit Cost Not yet Recognized Recorded as Regulatory Assets	

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2012				
Unrecognized transition obligation	$ -	$ -	$ 1,709	$ 1,709
Unrecognized prior service cost	(232)	-	(7,411)	(7,643)
Unrecognized actuarial loss	187,050	43,995	63,402	294,447
	$ 186,818	$ 43,995	$ 57,700	$ 288,513
September 30, 2011				
Unrecognized transition obligation	$ -	$ -	$ 3,220	$ 3,220
Unrecognized prior service cost	(373)	-	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$ 182,113	$ 30,654	$ 41,899	$ 254,666

Schedule of Allocation of Plan Assets

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

Schedule of Assumptions Used for Employee Pension Plans

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

Schedule of Accumulated and Projected Benefit Obligations and Funded Status for Employee Pension Plans

	2012	2011
	(In thousands)	
Accumulated benefit obligation	$ 468,440	$ 414,489
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 429,432	$ 407,536
Service cost	15,084	14,384

Interest cost	21,568	22,264
Actuarial loss	46,197	12,944
Benefits paid	(24,553)	(27,534)
Divestitures	(7,697)	-
Curtailments	-	(162)
Benefit obligation at end of year	480,031	429,432
Change in plan assets:		
Fair value of plan assets at beginning of year	280,204	301,708
Actual return on plan assets	48,656	5,154
Employer contributions	46,534	876
Benefits paid	(24,553)	(27,534)
Divestitures	(7,697)	-
Fair value of plan assets at end of year	343,144	280,204
Reconciliation:		
Funded status	(136,887)	(149,228)
Unrecognized prior service cost	-	-
Unrecognized net loss	-	-
Net amount recognized	$ (136,887)	$ (149,228)

Components of Net Periodic Pension Cost Table for Employee Pension Plans

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

Schedule of Employee Pension Plans Investments at Fair Value

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

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

Schedule of Assumptions Used for Supplemental Plans

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

Schedule of Accumulated and Projected Benefit Obligations and Funded Status for Supplemental Plans

	2012	2011
	(In thousands)	

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

Components of Net Periodic Pension Cost Table for Supplemental Plans

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

Schedule of Expected Benefit Payments

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

Schedule of Allocation of Postretirement Benefit Plan Assets

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

Schedule of Assumptions Used for Postretirement Benefit Plan

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

Schedule of Accumulated and Projected Benefit Obligations and Funded Status for Postretirement Benefit Plan

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

Components of Net Periodic Pension Cost Table for Postretirement Benefit Plan

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

Net periodic postretirement cost	$ 30,316	$ 24,897	$ 23,485

Assumed Heath Care Cost Effect on Postretirement Benefit Plan Cost

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

Schedule of Postretirement Benefit Plans Investments at Fair Value

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

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

Schedule of Expected Benefit Payments for Postretirement Benefit Plan

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

Intangible Assets (Details) (USD $) In Thousands, unless otherwise specified	Sep. 30, 2012	Sep. 30, 2011
Finite Lived Intangible Assets [Line Items]		
Net	$ 164	$ 207

Cash Flow, Supplemental Disclosures (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Supplemental Cash Flow Information Abstract			
Cash paid for interest	$ 150,606	$ 157,976	$ 161,925
Cash paid (received) for income taxes	$ (432)	$ (8,329)	$ (63,677)

CONSOLIDATED BALANCE SHEETS (USD $) In Thousands, unless otherwise specified	Sep. 30, 2012	Sep. 30, 2011
ASSETS		
Property, plant and equipment	$ 6,860,358	$ 6,607,552
Construction in progress	274,112	209,242
Total property, plant and equipment and construction in progress	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, net	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
Total assets	7,495,675	7,282,871
Shareholders' equity		
Common stock, no par value (stated at $.005 per share)	451	451
Additional paid-in capital	1,745,467	1,732,935
Retained earnings	660,932	570,495
Accumulated other comprehensive income (loss)	(47,607)	(48,460)
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
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
Total shareholders' equity and liabilities	$ 7,495,675	$ 7,282,871

Leases (Table)	12 Months Ended Sep. 30, 2012	
Leases Tables [Abstract]		
Schedule of Future Minimum Lease Payments		
	Capital Leases	**Opera Leas**
	(In thousands)	
2013	$ 186	$
2014	186	
2015	186	
2016	186	
2017	186	
Thereafter	78	1
Total minimum lease payments	1,008	$ 1
Less amount representing interest	286	
Present value of net minimum lease payments	$ 722	

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY (USD $) In Thousands, except Share data, unless otherwise specified	Total	Common Stock [Member]	Additional Paid In Capital [Member]	Accumulated Other Comprehensive Income [Member]	Retained Earnings [Member]
Common shareholders' equity, beginning balance at Sep. 30, 2009	$ 2,176,761	$ 463	$ 1,791,129	$ (20,184)	$ 405,353
Common stock shares outstanding, balance at Sep. 30, 2009		92,551,709			
Comprehensive income:					
Net income (loss)	205,839				205,839
Unrealized holding gains (losses) on investments, net	1,745			1,745	
Treasury Lock Agreements Net	2,030			2,030	
Cash Flow Hedges, Net	(6,963)			(6,963)	
Repurchase of common stock, amount	(100,450)	(15)	(100,435)		
Repurchase of common stock, shares		(2,958,580)			
Repurchase of equity awards, amount	(1,191)	(1)	(1,191)		
Repurchase of equity awards, shares		(37,365)			
Cash dividends	(124,287)				(124,287)
Common stock issued:					
Direct stock purchase plan, amount	2,882	1	2,881		
Direct stock purchase plan, shares		103,529			
Retirement savings plan, amount	2,281	0	2,281		
Retirement savings plan, shares		79,722			
1998 Long-term incentive plan, amount	8,710	2	8,708		
1998 Long-term incentive plan, shares		421,706			
Employee stock-based compensation	10,894		10,894		
Outside directors stock-for-fee-plan, amount	97		97		

Stock Issued During Period Shares Directors Stock For Fee Plan		3,382			
Common shareholders' equity, ending balance at Sep. 30, 2010	2,178,348	451	1,714,364	(23,372)	486,905
Common stock shares outstanding, ending balance at Sep. 30, 2010		90,164,103			
Comprehensive income:					
Net income (loss)	207,601				207,601
Unrealized holding gains (losses) on investments, net	(1,647)			(1,647)	
Treasury Lock Agreements Net	(28,689)			(28,689)	
Cash Flow Hedges, Net	5,248			5,248	
Repurchase of common stock, amount	0	(2)	2		
Repurchase of common stock, shares		(375,468)			
Repurchase of equity awards, amount	(5,299)		(5,298)		
Repurchase of equity awards, shares		(169,793)			
Cash dividends	(124,011)				(124,011)
Common stock issued:					
Direct stock purchase plan, amount	(54)	0	(54)		
Direct stock purchase plan, shares		0			
1998 Long-term incentive plan, amount	13,889	3	13,886		
1998 Long-term incentive plan, shares		675,255			
Employee stock-based compensation	9,958		9,958		
Outside directors stock-for-fee-plan, amount	77		77		
Stock Issued During Period Shares Directors Stock For Fee Plan		2,385			
Common shareholders' equity, ending balance at Sep. 30, 2011	2,255,421	451	1,732,935	(48,460)	570,495

Common stock shares outstanding, ending balance at Sep. 30, 2011		90,296,482			
Comprehensive income:					
Net income (loss)	216,717				216,717
Unrealized holding gains (losses) on investments, net	3,103			3,103	
Treasury Lock Agreements Net	(10,116)			(10,116)	
Cash Flow Hedges, Net	7,866			7,866	
Repurchase of common stock, amount	(12,535)	(2)	(12,533)		
Repurchase of common stock, shares		(387,991)			
Repurchase of equity awards, amount	(5,219)	0	(5,219)		
Repurchase of equity awards, shares		(153,255)			
Cash dividends	(125,796)				(125,796)
Common stock issued:					
Direct stock purchase plan, amount	(65)	0	(65)		
Direct stock purchase plan, shares		0			
1998 Long-term incentive plan, amount	12,037	2	12,519		(484)
1998 Long-term incentive plan, shares		482,289			
Employee stock-based compensation	17,752		17,752		
Outside directors stock-for-fee-plan, amount	78		78		
Stock Issued During Period Shares Directors Stock For Fee Plan		2,375			
Common shareholders' equity, ending balance at Sep. 30, 2012	$ 2,359,243	$ 451	$ 1,745,467	$ (47,607)	$ 660,932
Common stock shares outstanding, ending balance at Sep. 30, 2012		90,239,900			

Stock and Other Compensation Plans (Details) (USD $)	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Accelerated Share Repurchase Agreement [Abstract]			
Repurchased Shares	3,334,048		
Accelerated Share Repurchases Payment	$ 100,000,000		
Accelerated Share Repurchases, Final Price Paid Per Share	$ 29.99		
Direct Stock Purchse Plan [Abstract]			
Minimum Initial Investment for Direct Stock Purchase Plan	1,250		
Minimum Continuing Investment for Direct Stock Purchase Plan	25		
Annual Maximum Investment for Direct Stock Purchase Plan	100,000		
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range [Line Items]			
Number of Options	10,094		
Weighted Average Exercise Price	$ 24.95		
Weighted Average Remaining Contractual Life	1.7		
Grant Date Weighted Average Fair Value Per Share	$ 0	$ 0	$ 0
Net Cash Proceeds From Stock Option Exercises	1,671,000	7,848,000	3,604,000
Income Tax Benefit From Stock Option Exercises	401,000	1,010,000	547,000
Total Intrinsic Value Of Options Exercised	256,000	1,263,000	239,000
Share Based Compensation Allocation And Classification In Financial Statements Abstract			
Stock Based Compensation Expense	19,200,000	11,600,000	12,700,000
Authorized Shares	8,700,000		
Share-based Compensation Arrangement by Share-based Payment Award, Number of Shares Available	1,949,088		
Share Based Compensation Arrangement By Share Based Payment Award Equity Instruments Other Than Options Additional Disclosures Abstract			
Nonvested at beginning of year-Shares	1,264,142	1,293,960	1,295,841
Nonvested at beginning of year-Weighted Average	$ 29.56	$ 27.28	$ 27.23
Granted-Shares	532,711	491,345	551,278
Granted-Weighted Average	$ 33.44	$ 33.10	$ 29.07
Vested-Shares	(494,308)	(464,321)	(493,957)
Vested-Weighted Average	$ 26.32	$ 27.21	$ 29.24
Forfeited-Shares	(39,963)	(56,842)	(59,202)
Forfeited-Weighted Average	$ 29.83	$ 27.56	$ 26.54
Nonvested at end of year-Shares	1,262,582	1,264,142	1,293,960
Nonvested at end of year-Weighted Average	$ 32.46	$ 29.56	$ 27.28
Unrecognized Compensation Cost	10,100,000		
Weighted Average Recognized Period	1.6		
Fair Value Restricted Stock Vested	13,000,000	12,600,000	14,400,000
Stock Repurchase Program [Abstract]			

Stock Repurchase Program, Number of Shares Authorized to be Repurchased	5,000,000		
Stock Repurchase Program, Period in Force	5		
Stock Repurchased During Period, Value	12,500,000		
Stock Repurchased During Period, Shares	387,991		
Summary Of Stock Option Activity [Abstract]			
Oustanding at beginning of year-Options	86,766	434,962	611,227
Outstanding at beginning of year-Weighted Average	$ 22.16	$ 22.46	$ 21.88
Granted-Options	0	0	0
Granted-Weighted Average	$ 0	$ 0	$ 0
Exercised-Options	(76,672)	(348,196)	(176,265)
Exercised-Weighted Average	$ 21.79	$ 22.54	$ 20.44
Forfeited-Options	0	0	0
Forfeited-Weighted Average	$ 0	$ 0	$ 0
Expired-Options	0	0	0
Expired-Weighted Average	$ 0	$ 0	$ 0
Outstanding at end of year-Options	10,094	86,766	434,962
Outstanding at end of year-Weighted Average	$ 24.95	$ 22.16	$ 22.46
Exercisable at end of year-Options	10,094	86,766	434,962
Exercisable at end of year-Weighted Average	$ 24.95	$ 22.16	$ 22.46
Outstanding Options Weighted Average Remaining Contractual Life	1.7	1.7	1.6
Intrinsic Value Outstanding Options	30,000	300,000	1,600,000
Exercisable Options Weighted Average Remaining Contractual Life	1.7	1.7	1.6
Intrinsic Value Of Exercisable Options	$ 30,000	$ 300,000	$ 1,600,000
Low Range Of Option Exercise Prices [Member]			
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range [Line Items]			
Number of Options	2,164		
Weighted Average Exercise Price	$ 21.23		
Weighted Average Remaining Contractual Life	0.4		
High Range Of Option Exercise Prices [Member]			
Share Based Compensation Shares Authorized Under Stock Option Plans Exercise Price Range [Line Items]			
Number of Options	7,930		
Weighted Average Exercise Price	$ 25.95		
Weighted Average Remaining Contractual Life	2.1		

Financial Instruments (Table)	12 Months Ended Sep. 30, 2012

Financial Instruments Note Tables [Abstract]

Schedule of financial instrument assets and liabilities at fair value

	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)

Oustanding commodity contracts volumes table

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

Financial instruments on the balance sheet

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
September 30, 2012			(In thousands)	
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)

September 30, 2011	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
	(In thousands)			
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)

Fair value hedges table

	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

Cash flow hedges table

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

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

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

Other comprehensive income from hedging table

	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)

Expected recognition in earnings of deferred losses in AOCI table

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

Details of Selected Consolidated Balance Sheet Captions (Details) (USD $) In Thousands, unless otherwise specified	Sep. 30, 2012	Sep. 30, 2011
Schedule of Accounts Receivable [Abstract]		
Billed accounts receivable	$ 177,953	$ 216,145
Unbilled revenue	42,694	48,006
Other accounts receivable	23,304	16,592
Total accounts receivable	243,951	280,743
Less: allowance for doubtful accounts	9,425	7,440
Net accounts receivable	234,526	273,303
Schedule of Other Current Assets [Abstract]		
Assets from risk management activities current	24,707	18,344
Deferred gas cost	31,359	33,976
Taxes receivable	1,291	9,215
Current deferred tax asset	27,091	76,725
Prepaid expenses	17,114	22,499
Current portion of leased assets receivable	168	2,013
Materials and supplies	5,872	4,113
Asset held for sale	154,571	140,571
Other	10,609	9,015
Total other current assets	272,782	316,471
Schedule of Other Current Liabilities [Abstract]		
Customer deposits	100,926	106,743
Accrued employee costs	37,675	38,558
Deferred gas costs	23,072	8,130
Accrued interest	34,451	37,557
Liabilitied from risk management activities current	85,381	15,453
Taxes payable	64,319	57,853
Pension and postretirement obligations	39,625	33,036
Regulatory cost of removal accrual	78,525	35,078
Liabilities held for sale	11,573	18,445
Other	14,118	16,710
Total	489,665	367,563
Schedule of Other Noncurrent Assets [Abstract]		
Marketable securities	64,398	52,633
Regulatory assets	334,551	278,920
Deferred financing costs	35,101	35,149
Assets from risk management activities noncurrent	2,283	998
Other	14,929	16,093
Total	451,262	383,793
Schedule of Other Noncurrent Liabilities [Abstract]		
Postretirement obligations	221,231	202,709

Retirement plan obligations	235,965	236,227
Customer advances for construction	12,937	13,967
Regulatory liabilities	5,638	13,823
Asset retirement obligation	10,394	13,574
Liabilities from risk management activities noncurrent	9,206	78,089
Other	12,555	6,306
Total	507,926	564,695
Schedule of Property, Plant and Equipment [Abstract]		
Production plant	5,020	7,412
Storage plant	232,260	198,422
Transmission plant	1,185,007	1,126,509
Distribution plant	4,680,877	4,496,263
General plant	717,568	737,850
Intangible plant	39,626	41,096
Total property, plant and equipment	6,860,358	6,607,552
Construction in progress	274,112	209,242
Total property, plant and equipment and construction in progress	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

14. Leases	12 Months Ended Sep. 30, 2012
Leases Disclosure [Abstract]	
14. Leases	(see below)

14. Leases

Capital and Operating Leases

We have entered into operating leases for office and warehouse space, vehicles and heavy equipment used in our operations. The remaining lease terms range from one to 21 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $1.3 and $1.3 million at September 30, 2012 and 2011. Accumulated depreciation for these capital leases totaled $0.9 and $0.9 million at September 30, 2012 and 2011. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2012 were as follows:

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

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

Fair Value Measurements (Table)

12 Months Ended Sep. 30, 2012

Fair Value Measurements Tables [Abstract]

Fair value measurements table

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

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

Liabilities:					
Financial instruments					
Natural gas distribution segment	$ -	$ 81,118	$ -	$ -	$ 81,118
Nonregulated segment(1)	9,324	128,384	-	(123,943)	13,765
Total liabilities	$ 9,324	$ 209,502	$ -	$ (123,943)	$ 94,883

Other fair value measurements table

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

Available for sale securities

	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

16. Cash Flow, Supplemental Disclosure	12 Months Ended Sep. 30, 2012
Supplemental Cash Flow Information Abstract	
16. Supplemental Cash Flow Disclosures	(see below)

16. Supplemental Cash Flow Disclosures

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

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

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

Income Taxes Rate Reconciliation (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Income Tax Expense Benefit Continuing Operations Income Tax Reconciliation Abstract			
Tax at statutory rate of 35%	$ 101,648	$ 103,743	$ 108,169
Common stock dividends deductible for tax reporting	2,096	1,930	1,785
State taxes (net of federal benefit)	(5,958)	8,109	11,493
Settlement of uncertain tax positions	1,831	(4,950)	0
Penalties	66	2,292	104
Other, net	2,735	(445)	1,222
Income tax expense (benefit)	$ 98,226	$ 106,819	$ 119,203

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY (PARENTHETICALS) (USD $) In Thousands, except Per Share data, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Cash Dividends Paid Per Share [Abstract]			
Cash dividends per share	$ 1.38	$ 1.36	$ 1.34
Treasury Locks, Tax Amount	$ (5,388)	$ (16,850)	$ 1,193
Unrealized holding gains on investments, Tax Amount	1,881	(953)	1,025
Cash Flow Hedges, Tax Amount	$ 5,029	$ 3,355	$ (4,452)

CONSOLIDATED BALANCE SHEETS (PARENTHETICALS) (USD $) In Thousands, except Share data, unless otherwise specified	Sep. 30, 2012	Sep. 30, 2011
Top Element 00250 Statement Condensed Consolidated Balance Sheets Unaudited Parentheticals [Abstract]		
Common Stock, Par Value Per Share	$ 0.000	$ 0.000
Common Stock, Stated Value Per Share	$ 0.005	$ 0.005
Common Stock, Shares Authorized	200,000,000	200,000,000
Common Stock, Shares, Issued	90,239,900	90,296,482
Allowance for doubtful accounts	$ 9,425	$ 7,440

9. Retirement and Post-retirement Employee Benefit Plans	12 Months Ended Sep. 30, 2012
Retirement and Post-Retirement Employee Benefit Plans Abstract	
9. Retirement and Post-Retirement Employee Benefit Plans	

9. Retirement and Post-Retirement Employee Benefit Plans

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

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets are as follows:

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
	(In thousands)			
September 30, 2012				
Unrecognized transition obligation	$ -	$ -	$ 1,709	$ 1,709
Unrecognized prior service cost	(232)	-	(7,411)	(7,643)
Unrecognized actuarial loss	187,050	43,995	63,402	294,447
	$ 186,818	$ 43,995	$ 57,700	$ 288,513
September 30, 2011				
Unrecognized transition obligation	$ -	$ -	$ 3,220	$ 3,220
Unrecognized prior service cost	(373)	-	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$ 182,113	$ 30,654	$ 41,899	$ 254,666

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2012, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

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

The Plan also provides for an additional annual allocation based upon a participant's age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan credited this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account is credited with interest on the employee's prior year account balance. A special grandfather benefit also applied through December 31, 2008, for participants who were at least age 50 as of January 1, 1999 and who were participants in one of the prior plans on December 31, 1998. Participants are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan which was enhanced, effective January 1, 2011.

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

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

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

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

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

The following table presents asset allocation information for the Master Trust as of September 30, 2012 and 2011.

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

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

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a September 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plans were determined as of September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

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

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

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

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

Reconciliation:

Funded status	(136,887)	(149,228)
Unrecognized prior service cost	-	-
Unrecognized net loss	-	-
Net amount recognized	$ (136,887)	$ (149,228)

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

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

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

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

Assets at Fair Value as of September 30, 2011

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

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

Supplemental Executive Benefits Plans

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

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

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2011, 2010 and 2009. These assumptions are presented in the following table:

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

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

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

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

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

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

Estimated Future Benefit Payments

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

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

Postretirement Benefits

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

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

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of ERISA. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute $28.3 million to our postretirement benefits plan during fiscal 2013.

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

We currently invest the assets funding our postretirement benefit plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2012 and 2011.

	Actual Allocation September 30	
Security Class	**2012**	**2011**
Diversified investment funds	97.0%	96.8%

Cash and cash equivalents	3.0%	3.2%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of September 30, 2012 and 2011 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2011, 2010 and 2009. The assumptions are presented in the following table:

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

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

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

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

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

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

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

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

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

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

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

Estimated Future Benefit Payments

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

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

Defined Contribution Plans

As of September 30, 2012, we maintained three defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan), the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan) and the Atmos Energy Holdings, LLC 401K Profit-Sharing Plan (the AEH 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees participate in our defined contribution plan, which was enhanced, effective January 1, 2011. Employees participating in the Pension Account Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into the Retirement Savings Plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings

Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

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

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to $10.5 million, $10.2 million, and $9.8 million for fiscal years 2012, 2011 and 2010. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code and applicable Treasury regulations. No discretionary contributions were made for fiscal years 2012, 2011 or 2010. At September 30, 2012 and 2011, the Retirement Savings Plan held 4.9 percent and 4.5 percent of our outstanding common stock.

The AEH 401K Profit-Sharing Plan covers substantially all AEH employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 75 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. The Company may elect to make safe harbor contributions up to four percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEH 401K Profit-Sharing Plan. Participants become fully vested in the discretionary profit-sharing contributions after three years of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. Discretionary contributions to the AEH 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.2 million, $1.3 million and $1.3 million for fiscal years 2012, 2011 and 2010.

Document and Entity Information (USD $)	12 Months Ended Sep. 30, 2012	Nov. 06, 2012	Mar. 31, 2012
Top Element 00100 Document Document And Entity Information [Abstract]			
Document Type	10-K		
Document Period End Date	Sep. 30, 2012		
Amendment Flag	false		
Entity Registrant Name	Atmos Energy Corporation		
Entity Central Index Key	0000731802		
Entity Current Reporting Status	Yes		
Entity Voluntary Filers	No		
Current Fiscal Year End Date	--09-30		
Entity Filer Category	Large Accelerated Filer		
Entity Well Known Seasoned Issuer	Yes		
Document Fiscal Year Focus	2012		
Document Fiscal Period Focus	FY		
Entity Common Stock Shares Outstanding		90,240,464	
Entity Public Float			$ 2,764,486,845

10. Details of Selected Consolidated Balance Sheet Captions	12 Months Ended Sep. 30, 2012
Details Of Selected Consolidated Balance Sheet Captions Disclosure [Abstract]	
10. Details of Selected Consolidated Balance Sheet Captions	**10. Details of Selected Consolidated Balance Sheet Captions** The following tables provide additional information regarding the composition of certain of our balance sheet captions.

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2012 and 2011:

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

Other current assets

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

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

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

Property, plant and equipment

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

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

Deferred charges and other assets

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

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

Other current liabilities

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

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

Deferred credits and other liabilities

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

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

CONSOLIDATED STATEMENTS OF INCOME (USD $) In Thousands, except Per Share data, unless otherwise specified	3 Months Ended								12 Months Ended		
	Sep. 30, 2012	Jun. 30, 2012	Mar. 31, 2012	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Operating revenues											
Operating revenues	$ 552,566	$ 576,414	$ 1,225,509	$ 1,083,994	$ 779,667	$ 833,168	$ 1,556,374	$ 1,117,226	$ 3,438,483	$ 4,286,435	$ 4,661,060
Purchased gas cost											
Purchased gas cost									2,114,744	2,985,615	3,346,924
Gross profit	249,389	293,171	425,787	355,392	237,160	261,612	444,466	357,582	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	0
Total operating expenses									877,499	874,834	850,303
Operating income	22,791	81,546	202,432	139,471	39,195	31,394	204,624	150,773	446,240	425,986	463,833
Miscellaneous income (expense)									(14,644)	21,184	(591)
Interest charges									141,174	150,763	154,188
Income (loss) before income taxes									290,422	296,407	309,054
Income tax expense (benefit)									98,226	106,819	119,203
Income (loss) from continuing operations	(286)	28,014	102,084	62,384	237	(3,150)	124,293	68,208	192,196	189,588	189,851
Income (loss) from discontinued operations	1,904	3,118	7,027	6,123	1,724	2,584	7,916	5,789	18,172	18,013	15,988
Gain on sale of discountinued operations	6,349	0	0	0					6,349	0	0
Net income (loss)	7,967	31,132	109,111	68,507	1,961	(566)	132,209	73,997	216,717	207,601	205,839
Income Loss From Continuing Operations Per Basic Share	$ 0.00	$ 0.31	$ 1.12	$ 0.68	$ 0.00	$ (0.04)	$ 1.36	$ 0.75	$ 2.12	$ 2.08	$ 2.05
Income Loss From Discontinued Operations Net Of Tax Per Basic Share	$ 0.09	$ 0.03	$ 0.08	$ 0.07	$ 0.02	$ 0.03	$ 0.09	$ 0.06	$ 0.27	$ 0.20	$ 0.17
Basic net income (loss) per share	$ 0.09	$ 0.34	$ 1.20	$ 0.75	$ 0.02	$ (0.01)	$ 1.45	$ 0.81	$ 2.39	$ 2.28	$ 2.22
Income Loss From Continuing Operations Per Diluted Share	$ 0.00	$ 0.31	$ 1.12	$ 0.68	$ 0.00	$ (0.04)	$ 1.36	$ 0.75	$ 2.10	$ 2.07	$ 2.03
Income Loss From Discontinued Operations Net Of Tax Per Diluted Share	$ 0.09	$ 0.03	$ 0.08	$ 0.07	$ 0.02	$ 0.03	$ 0.09	$ 0.06	$ 0.27	$ 0.20	$ 0.17
Diluted net income (loss) per share	$ 0.09	$ 0.34	$ 1.20	$ 0.75	$ 0.02	$ (0.01)	$ 1.45	$ 0.81	$ 2.37	$ 2.27	$ 2.20
Weighted average shares outstanding:											
Basic									90,150	90,201	91,852
Diluted									91,172	90,652	92,422
Natural Gas Distribution Segment [Member]											
Operating revenues											
Operating revenues	282,516	315,634	871,067	676,113	334,363	396,584	1,052,291	687,426	2,145,330	2,470,664	2,783,863
Purchased gas cost											
Purchased gas cost									1,122,587	1,452,721	1,785,221

Gross profit									1,022,743	1,017,943	998,642
Operating expenses											
Operation and maintenance									353,879	341,758	349,465
Depreciation and amortization									202,026	193,642	182,097
Taxes, other than income									162,377	160,455	170,229
Asset impairments									0	0	
Total operating expenses									718,282	695,855	701,791
Operating income									304,461	322,088	296,851
Miscellaneous income (expense)									(12,657)	16,242	1,132
Interest charges									110,642	115,740	118,147
Income (loss) before income taxes									181,162	222,590	179,836
Income tax expense (benefit)									57,314	77,885	69,875
Income (loss) from continuing operations									123,848	144,705	109,961
Income (loss) from discontinued operations									18,172	18,013	15,988
Gain on sale of discountinued operations									6,349		
Net income (loss)									148,369	162,718	125,949
Regulated Transmission and Storage Segment [Member]											
Operating revenues											
Operating revenues	65,482	67,073	58,037	56,759	61,820	53,570	54,976	49,007	247,351	219,373	203,013
Purchased gas cost											
Purchased gas cost									0	0	0
Gross profit									247,351	219,373	203,013
Operating expenses											
Operation and maintenance									71,521	70,401	72,249
Depreciation and amortization									31,438	25,997	21,368
Taxes, other than income									15,568	14,700	12,358
Asset impairments									0	0	
Total operating expenses									118,527	111,098	105,975
Operating income									128,824	108,275	97,038
Miscellaneous income (expense)									(1,051)	4,715	135
Interest charges									29,414	31,432	31,174
Income (loss) before income taxes									98,359	81,558	65,999
Income tax expense (benefit)									35,300	29,143	24,513
Income (loss) from continuing operations									63,059	52,415	41,486
Income (loss) from discontinued operations									0	0	0
Gain on sale of discountinued operations									0		
Net income (loss)									63,059	52,415	41,486
Nonregulated Segment [Member]											
Operating revenues											
Operating revenues	280,114	256,250	370,763	444,176	474,437	491,285	583,531	475,640	1,351,303	2,024,893	2,146,658
Purchased gas cost											
Purchased gas cost									1,296,179	1,959,893	2,032,567
Gross profit									55,124	65,000	114,091
Operating expenses											

Operation and maintenance									29,697	32,308	34,517
Depreciation and amortization									4,061	4,193	5,074
Taxes, other than income									3,128	2,612	4,556
Asset impairments									5,288	30,270	
Total operating expenses									42,174	69,383	44,147
Operating income									12,950	(4,383)	69,944
Miscellaneous income (expense)									1,035	657	3,859
Interest charges									3,084	4,015	10,584
Income (loss) before income taxes									10,901	(7,741)	63,219
Income tax expense (benefit)									5,612	(209)	24,815
Income (loss) from continuing operations									5,289	(7,532)	38,404
Income (loss) from discontinued operations									0	0	0
Gain on sale of discountinued operations									0		
Net income (loss)									5,289	(7,532)	38,404
Intersegment Elimination [Member]											
Operating revenues											
Operating revenues	(75,546)	(62,543)	(74,358)	(93,054)	(90,953)	(108,271)	(134,424)	(94,847)	(305,501)	(428,495)	(472,474)
Purchased gas cost											
Purchased gas cost									(304,022)	(426,999)	(470,864)
Gross profit									(1,479)	(1,496)	(1,610)
Operating expenses											
Operation and maintenance									(1,484)	(1,502)	(1,610)
Depreciation and amortization									0	0	0
Taxes, other than income									0	0	0
Asset impairments									0	0	
Total operating expenses									(1,484)	(1,502)	(1,610)
Operating income									5	6	0
Miscellaneous income (expense)									(1,971)	(430)	(5,717)
Interest charges									(1,966)	(424)	(5,717)
Income (loss) before income taxes									0	0	0
Income tax expense (benefit)									0	0	0
Income (loss) from continuing operations									0	0	0
Income (loss) from discontinued operations									0	0	0
Gain on sale of discountinued operations									0		
Net income (loss)									$ 0	$ 0	$ 0

4. Financial Instruments	12 Months Ended Sep. 30, 2012

Derivative Instruments And Hedging Activities Disclosure [Abstract]

4. Financial Instruments

4. Financial Instruments

We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

As discussed in Note 2, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2012 and 2011:

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

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

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

3. The September 30, 2012 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Georgia operations. At September 30, 2012, assets and liabilities held for sale

included $0.1 million of current assets from risk management activities and $0.3 million of current liabilities from risk management activities.

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

Regulated Commodity Risk Management Activities

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

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

Nonregulated Commodity Risk Management Activities

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

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

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

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

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

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

Interest Rate Risk Management Activities

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

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

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

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

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

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

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

Quantitative Disclosures Related to Financial Instruments

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

As of September 30, 2012, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2012, we had net long/(short) commodity contracts outstanding in the following quantities:

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

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of September 30, 2012 and 2011. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $23.7 million and $28.8 million of cash held on deposit in margin accounts as of September 30, 2012 and 2011 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 5.

Natural

September 30, 2012	Balance Sheet Location	Gas Distribution	Nonregulated	Total
			(In thousands)	
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.

September 30, 2011	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
	(In thousands)			
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ -	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	-	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	-	(31,064)	(31,064)

Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities(1)	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$ (79,277)	$ (25,050)	$ (104,327)

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

Impact of Financial Instruments on the Income Statement

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

Fair Value Hedges

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

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

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

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

Cash Flow Hedges

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

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

	Fiscal Year Ended September 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into purchased gas cost for effective portion of commodity contracts	$ -	$ -	$ (28,430)	$ (28,430)
Loss arising from ineffective portion of commodity contracts	-	-	(1,585)	(1,585)
Total impact on purchased gas cost	-	-	(30,015)	(30,015)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,455)	-	-	(2,455)
Gain on unwinding of Treasury lock reclassified				

from AOCI into miscellaneous income	21,803	6,000	-	27,803
Total impact from cash flow hedges	$ 19,348	$ 6,000	$ (30,015)	$ (4,667)

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

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the years ended September 30, 2012 and 2011. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

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

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

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

	Treasury Lock	Commodity

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

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

Financial Instruments Not Designated as Hedges

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

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

3. Goodwill and Intangible Assets	12 Months Ended Sep. 30, 2012
Goodwill And Intangible Assets Disclosure Abstract	
3. Goodwill and Intangible Assets	

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 2001and fiscal 2004, which resulted in an increase to goodwill and net deferred tax liabilities of $0.7 million.

15. Concentration of Credit Risk	12 Months Ended Sep. 30, 2012

Disclosure Concentration of Credit Risk

15. Concentration of Credit Risk

15. Concentration of Credit Risk

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

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

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2012, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers, including affiliate customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2012 and 2011.

	September 30, 2012	September 30, 2011
Investment grade	60%	54%
Non-investment grade	40%	46%
Total	100%	100%

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2012. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Natural Gas Distribution Segment [1]	Nonregulated Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$ -	$ 4	$ 4
Non-investment grade counterparties	-	-	-
	$ -	$ 4	$ 4

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

11. Earnings Per Share

Disclosure Earnings Per Share

11. Earnings Per Share

12 Months Ended Sep. 30, 2012

11. Earnings Per Share

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

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

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

Diluted weighted average shares outstanding	91,172	90,652	92,422
Income from continuing operations per share - Diluted	$ 2.10	$ 2.07	$ 2.03
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Effect of dilutive stock options and other shares	-	-	-
Income from discontinued operations available to common shareholders	$ 24,420	$ 17,825	$ 15,824
Basic weighted average shares outstanding	90,150	90,201	91,852
Additional dilutive stock options and other shares	1,022	451	570
Diluted weighted average shares outstanding	91,172	90,652	92,422
Income from discontinued operations per share - Diluted	$ 0.27	$ 0.20	$ 0.17
Net income per share - Diluted	$ 2.37	$ 2.27	$ 2.20

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

7. Debt	12 Months Ended Sep. 30, 2012

Debt Disclosure [Abstract]

7. Debt

7. Debt

Long-term debt

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

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

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

Short-term debt

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

Prior to the fourth quarter of fiscal 2012, we financed our short-term borrowing requirements through a combination of a $750 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $985 million of working capital funding. On July 25, 2012, we increased the borrowing capacity of our $10 million revolving credit facility to $14 million. As a result of these changes, we have $989 million of working capital funding at September 30, 2012. At September 30, 2012 and 2011, there was $310.9 million and $206.4 million outstanding under our commercial paper program. As of September 30, 2012 our commercial paper had maturities of approximately two months with interest rates of 0.43 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

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

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

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

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2012, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

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

Nonregulated Operations

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

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

At September 30, 2012, there were no borrowings outstanding under this credit facility. However, at September 30, 2012, AEM letters of credit totaling $11.5 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $138.5 million at September 30, 2012.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At September 30, 2012, AEM's ratio of total liabilities to tangible net worth, as defined, was 0.74 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at September 30, 2012, AEM's net working capital was $136.2 million and its tangible net worth was $150.8 million.

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

Shelf Registration

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

Debt Covenants

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

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

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

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

We were in compliance with all of our debt covenants as of September 30, 2012. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

Maturities of long-term debt at September 30, 2012 were as follows (in thousands):

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

Retirement and Post-Retirement Employee Benefit Plans Defined Benefit Plans Disclosure (Details) (USD $)	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Defined Benefit Plan Weighted Average Assumptions Used In Calculating Net Periodic Benefit Cost Abstract			
Unrecognized transition obligation	$ 1,709,000	$ 3,220,000	
Unrecognized prior service cost	7,643,000	9,234,000	
Unrecognized actuarial loss	294,447,000	260,680,000	
Total unrecognized in net periodic cost	288,513,000	254,666,000	
Pension Plans Defined Benefit [Member]			
Defined Benefit Plan Weighted Average Assumptions Used In Calculating Net Periodic Benefit Cost Abstract			
Discount rate	5.05%	5.39%	5.52%
Rate of compensation increase	3.50%	4.00%	4.00%
Expected return on plan assets	7.75%	8.25%	8.25%
Unrecognized transition obligation	0	0	
Unrecognized prior service cost	232,000	373,000	
Unrecognized actuarial loss	187,050,000	182,486,000	
Total unrecognized in net periodic cost	186,818,000	182,113,000	
Defined Benefit Plan Weighted Average Assumptions Used In Calculating Benefit Obligation Abstract			
Discount rate	4.04%	5.05%	
Rate of compensation increase	3.50%	3.50%	
Expected return on plan assets	7.75%	7.75%	
Defined Benefit Plan Change In Benefit Obligation Roll Forward			
Benefit obligation at beginning of year	429,432,000	407,536,000	
Service cost	15,084,000	14,384,000	13,499,000
Interest cost	21,568,000	22,264,000	20,870,000
Actuarial (gain) loss	46,197,000	12,944,000	
Benefits paid	(24,553,000)	(27,534,000)	
Divestitures	(7,697,000)	0	
Curtailment loss	0	(162,000)	
Benefit obligation at end of year	480,031,000	429,432,000	407,536,000
Funded Status Reconciliation [Abstract]			
Funded status	(136,887,000)	(149,228,000)	
Unrecognized prior service cost	0	0	
Unrecognized net loss	0	0	
Net amount recognized	(136,887,000)	(149,228,000)	
Defined Benefit Plan Information About Plan Assets Abstract			
Number of shares of Atmos Energy common stock in Master Trust	1,169,700	1,169,700	
Amount of dividend income from Atmos Energy common stock in Master Trust	1,600,000	1,600,000	

Targeted Allocation Range Abstract			
Domestic Equities Targeted Allocation Range Minimum	35.00%		
Domestic Equities Targeted Allocation Range Maximum	55.00%		
International Equities Targeted Allocation Range Minimum	10.00%		
International Equities Targeted Allocation Range Maximum	20.00%		
Fixed Income Targeted Allocation Range Minimum	10.00%		
Fixed Income Targeted Allocation Range Maximum	30.00%		
Company Stock Targeted Allocation Range Minimum	5.00%		
Company Stock Targeted Allocation Range Maximum	15.00%		
Other Targeted Allocation Range Minimum	5.00%		
Other Targeted Allocation Range Maximum	15.00%		
Actual Allocation Abstract			
Domestic Equities Actual Allocation	42.60%	40.40%	
International Equities Actual Allocation	13.90%	13.60%	
Fixed Income Actual Allocation	18.60%	21.30%	
Company Stock Actual Allocation	12.00%	13.50%	
Other Actual Allocation	12.90%	11.20%	
Estimated Future Benefits Payment, Total			
Expected future benefit payments in year one, total	38,800,000		
Expected future benefit payments in year two, total	35,551,000		
Expected future benefit payments in year three, total	33,953,000		
Expected future benefit payments in year four, total	33,536,000		
Expected future benefit payments in year five, total	32,740,000		
Expected future benefit payments in five fiscal years thereafter, total	156,231,000		
Effect of One-Percentage Point Change in Assumed Health Care Cost Trend Rates			
Accumulated benefit obligation	468,440,000	414,489,000	
Fair value of accounts receivable	500,000	400,000	
Other Postretirement Benefit Plans Defined Benefit [Member]			
Defined Benefit Plan Weighted Average Assumptions Used In Calculating Net Periodic Benefit Cost Abstract			
Discount rate	5.05%	5.39%	5.52%
Expected return on plan assets	5.00%	5.00%	5.00%
Initial trend	8.00%	8.00%	7.50%
Ultimate trend rate	5.00%	5.00%	5.00%
Ultimate trend rate reached in	2018	2016	2015
Unrecognized transition obligation	1,709,000	3,220,000	
Unrecognized prior service cost	7,411,000	8,861,000	
Unrecognized actuarial loss	63,402,000	47,540,000	
Total unrecognized in net periodic cost	57,700,000	41,899,000	
Defined Benefit Plan Weighted Average Assumptions Used In Calculating Benefit Obligation Abstract			
Discount rate	4.04%	5.05%	
Expected return on plan assets	4.70%	5.00%	

Initial trend	8.00%	8.00%	
Ultimate trend rate	5.00%	5.00%	
Ultimate trend rate reached in	2019	2018	
Defined Benefit Plan Change In Benefit Obligation Roll Forward			
Benefit obligation at beginning of year	263,694,000	228,234,000	
Service cost	16,353,000	14,403,000	13,439,000
Interest cost	13,861,000	12,813,000	12,071,000
Plan participants' contributions	3,649,000	2,892,000	
Actuarial (gain) loss	28,815,000	17,966,000	
Benefits paid	(13,197,000)	(13,046,000)	
Divestitures	(4,860,000)	0	
Subsidy Payments	0	432,000	
Benefit obligation at end of year	308,315,000	263,694,000	228,234,000
Funded Status Reconciliation [Abstract]			
Funded status	(231,243,000)	(210,629,000)	
Unrecognized prior service cost	0	0	
Unrecognized transition obligation	0	0	
Unrecognized net loss	0	0	
Net amount recognized	(231,243,000)	(210,629,000)	
Actual Allocation Abstract			
Diversified investment funds	97.00%	96.80%	
Cash and cash equivalents	3.00%	3.20%	
Estimated company benefit payments			
Estimated company benefit payments in year one	28,317,000		
Estimated company benefit payments in year two	15,174,000		
Estimated company benefit payments in year three	17,349,000		
Estimated company benefit payments in year four	19,221,000		
Estimated company benefit payments in year five	20,520,000		
Estimated company benefit payments in five fiscal years thereafter	107,055,000		
Estimated retiree benefit payments			
Estimated retiree benefit payments in year one	3,696,000		
Estimated retiree benefit payments in year two	4,487,000		
Estimated retiree benefit payments in year three	5,251,000		
Estimated retiree benefit payments in year four	6,128,000		
Estimated retiree benefit payments in year five	7,083,000		
Estimated retiree benefit payments in five fiscal years thereafter	48,114,000		
Disclosure Of Expected Gross Prescription Drug Subsidy Receipts Abstract			
Prescription drug subsidy receipts in year one	0		
Prescription drug subsidy receipts in year two	0		
Prescription drug subsidy receipts in year three	0		
Prescription drug subsidy receipts in year four	0		
Prescription drug subsidy receipts in year five	0		
Prescription drug subsidy receipts in five fiscal years thereafter	0		

Estimated Future Benefits Payment, Total			
Expected future benefit payments in year one, total	32,013,000		
Expected future benefit payments in year two, total	19,661,000		
Expected future benefit payments in year three, total	22,600,000		
Expected future benefit payments in year four, total	25,349,000		
Expected future benefit payments in year five, total	27,603,000		
Expected future benefit payments in five fiscal years thereafter, total	155,169,000		
Effect of One-Percentage Point Change in Assumed Health Care Cost Trend Rates			
Effect of One Percentage Point Increase on Service and Interest Cost Components	1,426,000		
Effect of One Percentage Point Decrease on Service and Interest Cost Components	(1,287,000)		
Effect of One Percentage Point Increase on Accumulated Postretirement Benefit Obligation	21,736,000		
Effect of One Percentage Point Decrease on Accumulated Postretirement Benefit Obligation	(18,866,000)		
Supplemental Executive Retirement Plans, Defined Benefit [Member]			
Defined Benefit Plan Weighted Average Assumptions Used In Calculating Net Periodic Benefit Cost Abstract			
Discount rate	5.05%	5.39%	5.52%
Rate of compensation increase	3.50%	4.00%	4.00%
Unrecognized transition obligation	0	0	
Unrecognized prior service cost	0	0	
Unrecognized actuarial loss	43,995,000	30,654,000	
Total unrecognized in net periodic cost	43,995,000	30,654,000	
Defined Benefit Plan Weighted Average Assumptions Used In Calculating Benefit Obligation Abstract			
Discount rate	4.04%	5.05%	
Rate of compensation increase	3.50%	3.50%	
Defined Benefit Plan Change In Benefit Obligation Roll Forward			
Benefit obligation at beginning of year	112,115,000	108,919,000	
Service cost	2,108,000	2,768,000	2,476,000
Interest cost	5,142,000	5,825,000	5,224,000
Actuarial (gain) loss	15,459,000	2,140,000	
Benefits paid	(4,638,000)	(7,537,000)	
Benefit obligation at end of year	130,186,000	112,115,000	108,919,000
Funded Status Reconciliation [Abstract]			
Funded status	(130,186,000)	(112,115,000)	
Unrecognized prior service cost	0	0	
Unrecognized net loss	0	0	
Net amount recognized	(130,186,000)	(112,115,000)	
Estimated Future Benefits Payment, Total			
Expected future benefit payments in year one, total	31,108,000		
Expected future benefit payments in year two, total	13,453,000		

Expected future benefit payments in year three, total	7,658,000	
Expected future benefit payments in year four, total	4,680,000	
Expected future benefit payments in year five, total	7,385,000	
Expected future benefit payments in five fiscal years thereafter, total	41,830,000	
Effect of One-Percentage Point Change in Assumed Health Care Cost Trend Rates		
Accumulated benefit obligation	$ 121,815,000	$ 104,363,000

5. Fair Value Measurements	12 Months Ended Sep. 30, 2012

Fair Value Measurements [Abstract]

5. Fair Value Measurements

5. Fair Value Measurements

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

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

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2012 and 2011. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

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

Total liabilities	$ 4,563	$ 276,734	$ -	$ (186,451)	$ 94,846

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

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

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

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

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

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

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of September 30, 2012:				
Domestic equity mutual funds	$ 25,779	$ 8,183	$ -	$ 33,962
Foreign equity mutual funds	5,568	682	-	6,250

Bonds	22,358	196	(2)	22,552
Money market funds	1,634	-	-	1,634
	$ 55,339	$ 9,061	$ (2)	$ 64,398
As of September 30, 2011:				
Domestic equity mutual funds	$ 27,748	$ 4,074	$ -	$ 31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	-	-	1,823
	$ 48,558	$ 4,351	$ (276)	$ 52,633

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

Other Fair Value Measures

In addition to the financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The nonfinancial assets and liabilities include asset retirement obligations and pension and post-retirement plan assets. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities.

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

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

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

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

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

6. Discontinued Operations

12 Months Ended Sep. 30, 2012

Discontinued Operations [Abstract]

6. Discontinued Operations

6. Discontinued Operations

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

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

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

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

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

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

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

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

8. Stock and Other Compensation Plans	12 Months Ended Sep. 30, 2012
Disclosure Of Compensation Related Costs Share Based Payments Abstract	
8. Stock and Other Compensation Plans	

8. Stock and Other Compensation Plans

Share Repurchase Agreement

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

Share Repurchase Program

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

Stock-Based Compensation Plans

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

1998 Long-Term Incentive Plan

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

As of September 30, 2012, we were authorized to grant awards for up to a maximum of 8.7 million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2012, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 1,949,088 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years. However, no stock options have been granted under this plan since fiscal 2003, except for a limited number of options that were converted from bonuses paid under our Annual Incentive Plan, the last of which occurred in fiscal 2006.

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock units to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The fair value of the awards granted is based on the market price of our stock at the date of grant. The associated expense is recognized ratably over the vesting period.

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

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

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

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

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

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2012		2011		2010	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	86,766	$ 22.16	434,962	$ 22.46	611,227	$ 21.88
Granted	-	-	-	-	-	-
Exercised	(76,672)	21.79	(348,196)	22.54	(176,265)	20.44
Forfeited	-	-	-	-	-	-
Expired	-	-	-	-	-	-
Outstanding at end of year(1)	10,094	$ 24.95	86,766	$ 22.16	434,962	$ 22.46
Exercisable at end of year(2)	10,094	$ 24.95	86,766	$ 22.16	434,962	$ 22.46

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

Information about outstanding and exercisable options under the LTIP, as of September 30, 2012, is reflected in the following tables:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price
$21.23 to $22.99	2,164	0.4	$ 21.23
$23.00 to $25.95	7,930	2.1	$ 25.95
$21.23 to $25.95	10,094	1.7	$ 24.95

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

As of September 30, 2012, there was no unrecognized compensation cost related to nonvested stock options.

Other Plans

Direct Stock Purchase Plan

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

Outside Directors Stock-For-Fee Plan

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

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

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

Other Discretionary Compensation Plans

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

In addition, we adopted an incentive plan in October 2001 to give the employees in our nonregulated segment an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure is based upon the net earnings of the nonregulated operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

Retirement and Post-Retirement Employee Benefit Plans Defined Contribution Plans (Details) (USD $) In Millions, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Defined Contribution Pension And Other Postretirement Plans Disclosure Abstract			
Retirement Savings Plan and Union 401K matching contributions expense	$ 10.5	$ 10.2	$ 9.8
Percent of Atmos Energy common stock in Retirement Savings Plan	4.90%	4.50%	
AEM 401K Profit-Sharing Plan Discretionary Contributions	$ 1.2	$ 1.3	$ 1.3

Earnings Per Share (Details) (USD $) In Thousands, except Per Share data, unless otherwise specified	3 Months Ended								12 Months Ended		
	Sep. 30, 2012	Jun. 30, 2012	Mar. 31, 2012	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Basic Earnings per Share from Continuing Operations											
Income (loss) from continuing operations	$ (286)	$ 28,014	$ 102,084	$ 62,384	$ 237	$ (3,150)	$ 124,293	$ 68,208	$ 192,196	$ 189,588	$ 189,851
Less: Income (loss) from continuing operations allocated to participating securities									793	1,980	1,943
Income (loss) from continuing operations available to common shareholders									191,403	187,608	187,908
Income Loss From Continuing Operations Per Basic Share	$ 0.00	$ 0.31	$ 1.12	$ 0.68	$ 0.00	$ (0.04)	$ 1.36	$ 0.75	$ 2.12	$ 2.08	$ 2.05
Basic Earnings per Share from Discontinued Operations											
Net income (loss) from discontinued operations									24,521	18,013	15,988
Less: Income (loss) from discontinued operations allocated to participating securities									101	188	164
Income (loss) from discontinued operations available to common shareholders									24,420	17,825	15,824
Income (loss) from discontinued operations per share - Basic	$ 0.09	$ 0.03	$ 0.08	$ 0.07	$ 0.02	$ 0.03	$ 0.09	$ 0.06	$ 0.27	$ 0.20	$ 0.17
Basic net income (loss) per share	$ 0.09	$ 0.34	$ 1.20	$ 0.75	$ 0.02	$ (0.01)	$ 1.45	$ 0.81	$ 2.39	$ 2.28	$ 2.22
Basic									90,150	90,201	91,852
Diluted Earnings per Share from Continuing Operations											
Effect of dilutive stock options and other shares									4	4	5
Income (loss) from continuing operations available to common shareholders									191,407	187,612	187,913
Additional dilutive stock options and other shares									1,022	451	570

Diluted									91,172	90,652	92,422
Income Loss From Continuing Operations Per Diluted Share	$ 0.00	$ 0.31	$ 1.12	$ 0.68	$ 0.00	$ (0.04)	$ 1.36	$ 0.75	$ 2.10	$ 2.07	$ 2.03
Diluted Earnings per Share from Discontinued Operations											
Effect of dilutive stock options and other shares									0	0	0
Income (loss) from discontinued operations available to common shareholders									$ 24,420	$ 17,825	$ 15,824
Additional dilutive stock options and other shares									1,022	451	570
Diluted weighted average shares outstanding									91,172	90,652	92,422
Income (loss) from discontinued operations per share - Diluted	$ 0.09	$ 0.03	$ 0.08	$ 0.07	$ 0.02	$ 0.03	$ 0.09	$ 0.06	$ 0.27	$ 0.20	$ 0.17
Diluted net income (loss) per share	$ 0.09	$ 0.34	$ 1.20	$ 0.75	$ 0.02	$ (0.01)	$ 1.45	$ 0.81	$ 2.37	$ 2.27	$ 2.20

Retirement and Post-Retirement Employee Benefit Plans Net Periodic Cost (Details) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Pension Plans Defined Benefit [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Service cost	$ 15,084	$ 14,384	$ 13,499
Interest cost	21,568	22,264	20,870
Expected return on assets	21,474	24,817	25,280
Amortization of prior service cost	(141)	(429)	(960)
Recognized actuarial loss	(14,451)	(9,498)	(9,290)
Curtailment loss	0	40	0
Net periodic cost	29,488	20,860	17,419
Other Postretirement Benefit Plans Defined Benefit [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Service cost	16,353	14,403	13,439
Interest cost	13,861	12,813	12,071
Expected return on assets	2,607	2,727	2,460
Amortization of transition asset	1,511	1,511	1,511
Amortization of prior service cost	(1,450)	(1,450)	(1,450)
Recognized actuarial loss	(2,648)	(347)	(374)
Net periodic cost	30,316	24,897	23,485
Supplemental Executive Retirement Plans, Defined Benefit [Member]			
Defined Benefit Plan Disclosure [Line Items]			
Service cost	2,108	2,768	2,476
Interest cost	5,142	5,825	5,224
Amortization of transition asset	0	0	0
Amortization of prior service cost	0	0	187
Recognized actuarial loss	(2,118)	(2,239)	(1,999)
Net periodic cost	$ 9,368	$ 10,832	$ 9,886

Goodwill and Intangible Assets (Table)

Goodwill And Intangible Assets Note Tables [Abstract]

Schedule of goodwill

12 Months Ended Sep. 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

Summary of Significant Accounting Policies (Details) (USD $)	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Regulatory Liabilities [Line Items]			
Description of Specific Regulatory Assets	During the prior fiscal year, the Railroad Commission of Texas' Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing) at which time investment and costs would be recovered through base rates. As of September 30, 2012, we had deferred $5.4 million associated with the requirements of this rule. Effective January 1, 2012, the Texas Legislature amended its Gas Utility Regulatory Act (GURA) to permit natural gas utilities to defer into a regulatory asset or liability the difference between a gas utility's actual pension and postretirement expense and the level of such expense recoverable in its existing rates. The deferred amount will become eligible for inclusion in the utility's rates in its next rate proceeding. We elected to utilize this provision of GURA, effective January 1, 2012, and established a regulatory asset totaling $7.6 million, which is recorded in "Pension and postretirement benefit costs" in the regulatory assets table above. Of this amount, $4.2 million represented a reduction to operation and maintenance expense during fiscal 2012.		
Accumulated Other Comprehensive Income Loss Net Of Tax Abstract			
Accumulated Other Comprehensive Income Loss Available For Sale Securities Adjustment Net Of Tax	$ 5,661,000	$ 2,558,000	
Accumulated Other Comprehensive Income Loss Cumulative Changes In Net Gain Loss From Interest Rate Hedges Effect Net Of Tax	(44,273,000)	(34,157,000)	
Accumulated Other Comprehensive Income Loss	(8,995,000)	(16,861,000)	

Cumulative Changes In Net Gain Loss From Cash Flow Hedges Effect Net Of Tax			
Accumulated other comprehensive income (loss)	(47,607,000)	(48,460,000)	
Other Information [Abstract]			
Other Deferred Cost Amortization Expense	500,000	500,000	400,000
Unrealized gain (loss) on open contracts	(8,000,000)	(10,400,000)	(7,800,000)
Interest Costs Capitalized	2,600,000	1,700,000	3,900,000
Composite depreciation rate for regulated property, plant and equipment	3.60%	3.60%	3.50%
Asset Retirement Obligation	10,500,000	14,000,000	
Asset Retirement Costs in Property, Plant and Equipment	4,200,000	5,400,000	
Deferred Gas Costs Liability [Member]			
Regulatory Liabilities [Line Items]			
Regulatory Liabilities	23,072,000	8,130,000	
APT Annual Adjustment Mechanism Liability [Member]			
Regulatory Liabilities [Line Items]			
Regulatory Liabilities	0	6,654,000	
Miscellaneous Regulatory Liabilities [Member]			
Regulatory Liabilities [Line Items]			
Regulatory Liabilities	5,637,000	7,371,000	
Regulatory Cost Of Removal Liability [Member]			
Regulatory Liabilities [Line Items]			
Regulatory Liabilities	459,688,000	464,025,000	
Pension And Postretirement Benefit Costs [Member]			
Regulatory Assets [Line Items]			
Regulatory Assets	296,160,000	254,666,000	
Merger And Integration Costs Net [Member]			

Regulatory Assets [Line Items]		
Regulatory Assets	5,754,000	6,242,000
Deferred Gas Costs Asset [Member]		
Regulatory Assets [Line Items]		
Regulatory Assets	31,359,000	33,976,000
Regulatory Cost of Removal Asset [Member]		
Regulatory Assets [Line Items]		
Regulatory Assets	10,500,000	8,852,000
Rate Case Costs [Member]		
Regulatory Assets [Line Items]		
Regulatory Assets	4,661,000	4,862,000
Deferred Franchise Fees [Member]		
Regulatory Assets [Line Items]		
Regulatory Assets	2,714,000	379,000
Risk-based Replacement Program Costs [Member]		
Regulatory Assets [Line Items]		
Regulatory Assets	5,370,000	0
APT Annual Adjustment Mechanism Asset [Member]		
Regulatory Assets [Line Items]		
Regulatory Assets	4,539,000	0
Deferred Miscellaneous Costs [Member]		
Regulatory Assets [Line Items]		
Regulatory Assets	$ 7,262,000	$ 3,919,000

13. Commitments and Contingencies

12 Months Ended Sep. 30, 2012

Commitments And Contingencies Disclosure [Abstract]

13. Commitments and Contingencies

13. Commitments and Contingencies

Litigation

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

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

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

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

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

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

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

Environmental Matters

Former Manufactured Gas Plant Sites

We are the owner or previous owner of former manufactured gas plant sites in Johnson City, Tennessee and Keokuk, Iowa, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa and the United States Environmental Protection Agency.

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

Purchase Commitments

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

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

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

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

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

2013	$	19,456
2014		10,554
2015		4,504
2016		278
2017		37

Thereafter		128
	$	34,957

Other Contingencies

In December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

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

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

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

18. Quarterly Financial Information	12 Months Ended Sep. 30, 2012
Selected Quarterly Financial Information Abstract	
18. Selected Quarterly Financial Data (Unaudited)	**18. Selected Quarterly Financial Data (Unaudited)** Summarized unaudited quarterly financial data is presented below. Prior-period amounts have been restated to reflect continuing operations. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the “Results of Operations” discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2012:				
Operating revenues				
Natural gas distribution	$ 676,113 (1)	$ 871,067 (2)	$ 315,634 (3)	$ 282,516
Regulated transmission and storage	56,759	58,037	67,073	65,482
Nonregulated	444,176	370,763	256,250	280,114
Intersegment eliminations	(93,054)	(74,358)	(62,543)	(75,546)
	1,083,994	1,225,509	576,414	552,566
Gross profit	355,392 (1)	425,787 (2)	293,171 (3)	249,389
Operating income	139,471 (1)	202,432 (2)	81,546 (3)	22,791
Income (loss) from continuing operations	62,384	102,084	28,014	(286)
Income from discontinued operations	6,123	7,027	3,118	1,904
Gain on sale of discontinued operations	-	-	-	6,349
Net income	68,507	109,111	31,132	7,967
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ 0.00
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share - basic	$ 0.75	$ 1.20	$ 0.34	$ 0.09
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ 0.00
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share - diluted	$ 0.75	$ 1.20	$ 0.34	$ 0.09

Fiscal year 2011:

Operating revenues				
Natural gas distribution	$ 687,426(4)	$ 1,052,291(5)	$ 396,584(6)	$ 334,363(7)
Regulated transmission and storage	49,007	54,976	53,570	61,820
Nonregulated	475,640	583,531	491,285	474,437
Intersegment eliminations	(94,847)	(134,424)	(108,271)	(90,953)
	1,117,226	1,556,374	833,168	779,667
Gross profit	357,582(4)	444,466(5)	261,612(6)	237,160(7)
Operating income	150,773(4)	204,624(5)	31,394(6)	39,195(7)
Income (loss) from continuing operations	68,208	124,293	(3,150)	237
Income from discontinued operations	5,789	7,916	2,584	1,724
Net income (loss)	73,997	132,209	(566)	1,961
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.75	$ 1.36	$ (0.04)	$ 0.00
Income per share from discontinued operations	$ 0.06	0.09	$ 0.03	$ 0.02
Net income (loss) per share - basic	$ 0.81	$ 1.45	$ (0.01)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.75	$ 1.36	$ (0.04)	$ 0.00
Income per share from discontinued operations	$ 0.06	$ 0.09	$ 0.03	$ 0.02
Net income (loss) per share - diluted	$ 0.81	$ 1.45	$ (0.01)	$ 0.02

1. Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.2 million, $7.5 million and $4.9 million, which were not previously reported as discontinued operations.
2. Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.9 million, $8.5 million and $5.9 million, which were not previously reported as discontinued operations.
3. Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $9.4 million, $5.6 million and $3.2 million, which were not previously reported as discontinued operations.
4. Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $16.0 million, $7.1 million and $4.5 million, which were not previously reported as discontinued operations.
5. Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $25.1 million, $9.2 million and $6.6 million, which were not previously reported as discontinued operations.
6. Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $10.4

million, \$5.2 million and \$2.7 million, which were not previously reported as discontinued operations.

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

Quarterly Financial Information (Table)	12 Months Ended Sep. 30, 2012

Schedule of Quarterly Financial Information Table [Abstract]

Schedule of Quarterly Financial Information

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2012:				
Operating revenues				
Natural gas distribution	$ 676,113[(1)]	$ 871,067[(2)]	$ 315,634[(3)]	$ 282,516
Regulated transmission and storage	56,759	58,037	67,073	65,482
Nonregulated	444,176	370,763	256,250	280,114
Intersegment eliminations	(93,054)	(74,358)	(62,543)	(75,546)
	1,083,994	1,225,509	576,414	552,566
Gross profit	355,392[(1)]	425,787[(2)]	293,171[(3)]	249,389
Operating income	139,471[(1)]	202,432[(2)]	81,546[(3)]	22,791
Income (loss) from continuing operations	62,384	102,084	28,014	(286)
Income from discontinued operations	6,123	7,027	3,118	1,904
Gain on sale of discontinued operations	-	-	-	6,349
Net income	68,507	109,111	31,132	7,967
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ 0.00
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share - basic	$ 0.75	$ 1.20	$ 0.34	$ 0.09
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.68	$ 1.12	$ 0.31	$ 0.00
Income per share from discontinued operations	$ 0.07	$ 0.08	$ 0.03	$ 0.09
Net income per share - diluted	$ 0.75	$ 1.20	$ 0.34	$ 0.09
Fiscal year 2011:				
Operating revenues				
Natural gas distribution	$ 687,426[(4)]	$ 1,052,291[(5)]	$ 396,584[(6)]	$ 334,363[(7)]
Regulated transmission and storage	49,007	54,976	53,570	61,820
Nonregulated	475,640	583,531	491,285	474,437
Intersegment eliminations	(94,847)	(134,424)	(108,271)	(90,953)

		1,117,226		1,556,374		833,168		779,667
Gross profit		357,582(4)		444,466(5)		261,612(6)		237,160(7)
Operating income		150,773(4)		204,624(5)		31,394(6)		39,195(7)
Income (loss) from continuing operations		68,208		124,293		(3,150)		237
Income from discontinued operations		5,789		7,916		2,584		1,724
Net income (loss)		73,997		132,209		(566)		1,961
Basic earnings per share								
Income (loss) per share from continuing operations	$	0.75	$	1.36	$	(0.04)	$	0.00
Income per share from discontinued operations	$	0.06		0.09	$	0.03	$	0.02
Net income (loss) per share - basic	$	0.81	$	1.45	$	(0.01)	$	0.02
Diluted earnings per share								
Income (loss) per share from continuing operations	$	0.75	$	1.36	$	(0.04)	$	0.00
Income per share from discontinued operations	$	0.06	$	0.09	$	0.03	$	0.02
Net income (loss) per share - diluted	$	0.81	$	1.45	$	(0.01)	$	0.02

Details of Selected Consolidated Balance Sheet Captions (Table)	12 Months Ended Sep. 30, 2012

Details of Selected Consolidated Balance Sheet Captions Tables [Abstract]

Accounts Receivables Detail Table

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

Other Current Assets Detail Table

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

Property, Plant and Equipment Detail Table

	September 30 2012	September 30 2011
	(In thousands)	
Production plant	$ 5,020	$ 7,412
Storage plant	232,260	198,422
Transmission plant	1,185,007	1,126,509
Distribution plant	4,680,877	4,496,263
General plant	717,568	737,850
Intangible plant	39,626	41,096
	6,860,358	6,607,552
Construction in progress	274,112	209,242

	7,134,470	6,816,794
Less: accumulated depreciation and amortization	(1,658,866)	(1,668,876)
Net property, plant and equipment	$ 5,475,604	$ 5,147,918

Deferred Charges and Other Assets Detail Table

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

Other Current Liabilities Detail Table

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

Deferred Credits and Other Liabilities Detail Table

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

CONSOLIDATED STATEMENT OF INCOME (PARENTHETICALS) (USD $) In Thousands, unless otherwise specified	12 Months Ended		
	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Statement Of Income Parentheticals [Abstract]			
Discontinued Operation Tax Effect Of Income Loss From Discontinued Operation During Phase Out Period	$ 10,066	$ 12,372	$ 9,584
Discontinued Operation, Tax Effect of Income (Loss) from Disposal of Discontinued Operation	$ 3,519	$ 0	$ 0

2. Significant Accounting Policies	12 Months Ended Sep. 30, 2012
Significant Accounting Policies [Abstract]	
2. Summary of Significant Accounting Policies	

2. Summary of Significant Accounting Policies

Principles of consolidation — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

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

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

Regulation — Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates.

We record regulatory assets as a component of other current assets and deferred charges and other assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded either on the face of the balance sheet or as a component of current liabilities, deferred income taxes or deferred credits and other liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2012 and 2011 included the following:

	September 30	
	2012	2011
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$ 296,160	$ 254,666
Merger and integration costs, net	5,754	6,242
Deferred gas costs	31,359	33,976
Regulatory cost of removal asset	10,500	8,852
Rate case costs	4,661	4,862
Deferred franchise fees	2,714	379
Risk-based replacement program costs	5,370	-
APT annual adjustment mechanism	4,539	-

Other	7,262	3,919
	$ 368,319	$ 312,896
Regulatory liabilities:		
Deferred gas costs	$ 23,072	$ 8,130
Regulatory cost of removal obligation	459,688	464,025
APT annual adjustment mechanism	-	6,654
Other	5,637	7,371
	$ 488,397	$ 486,180

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

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

Currently, authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. During the fiscal years ended September 30, 2012, 2011 and 2010, we recognized $0.5 million, $0.5 million and $0.4 million in amortization expense related to these costs.

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

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

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

Operating revenues for our nonregulated segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our nonregulated activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2012, 2011 and 2010, we included unrealized gains (losses) on open contracts of $(8.0) million, $(10.4) million and $(7.8) million as a component of nonregulated revenues.

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

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

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

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

Regulated property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $2.6 million, $1.7 million and $3.9 million was capitalized in 2012, 2011 and 2010.

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

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.6 percent, 3.6 percent and 3.5 percent for the fiscal years ended September 30, 2012, 2011 and 2010.

Nonregulated property, plant and equipment — Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 50 years.

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

As of September 30, 2012 and 2011, we recorded asset retirement obligations of $10.5 million and $14.0 million. Additionally, we recorded $4.2 million and $5.4 million of asset retirement costs as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

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

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

During fiscal 2012, we recorded a pre-tax noncash impairment loss of $5.3 million related to our gathering systems in Kentucky. In fiscal 2011, we recorded pre-tax noncash impairment losses of $19.3 million related to our Fort Necessity storage project and $11.0 million related to our gathering systems in Kentucky. See Note 5 for further details.

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

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

Marketable securities — As of September 30, 2012 and 2011, all of our marketable securities were classified as available-for-sale. In accordance with the authoritative accounting standards, these securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on an individual investment by investment basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related investment is written down to its estimated fair value.

Financial instruments and hedging activities — We use financial instruments to mitigate commodity price risk in our natural gas distribution and nonregulated segments and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses and are discussed in Note 4.

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

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

Financial Instruments Associated with Commodity Price Risk

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

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

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

Gains and losses from hedge ineffectiveness are recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the financial instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity is referred to as timing ineffectiveness. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Our nonregulated segment also utilizes master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. As of September 30, 2012 and 2011, the Company netted $23.7 million and $28.8 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We manage interest rate risk, typically when we plan to issue new long-term debt or to refinance existing long-term debt. Prior to fiscal 2012, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement.

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

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

Fair Value Measurements **–** We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices), as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed.

We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

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

Level 1 **–** Represents unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities. The Level 1 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 **–** Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 – Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. As of September 30, 2012 our Master Trust owned one real estate investment that qualifies as a Level 3 fair value measurement. Currently, we have no other assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Our measurement date is September 30. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

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

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

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

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

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

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

Accumulated other comprehensive loss — Accumulated other comprehensive loss, net of tax, as of September 30, 2012 and 2011, consisted of the following unrealized gains (losses):

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

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

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

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

Debt (Details) (USD $)	12 Months Ended Sep. 30, 2012	Sep. 30, 2011
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	$ 1,960,131,000	$ 2,212,565,000
Debt Instrument Unamortized Discount	(3,695,000)	(4,014,000)
Current maturities of long-term debt	131,000	2,434,000
Total long-term debt	1,956,305,000	2,206,117,000
Long Term Debt By Maturity Abstract		
Long Term Debt Maturities Repayments Of Principal In Next Twelve Months	131,000	
Long Term Debt Maturities Repayments Of Principal In Year Two	0	
Long Term Debt Maturities Repayments Of Principal In Year Three	500,000,000	
Long Term Debt Maturities Repayments Of Principal In Year Four	0	
Long Term Debt Maturities Repayments Of Principal In Year Five	250,000,000	
Long Term Debt Maturities Repayments Of Principal After Year Five	1,210,000,000	
Total Debt Instrument Carrying Amount	1,960,131,000	2,212,565,000
Long Term Debt Other Disclosures [Abstract]		
Authorized Commercial Paper	750,000,000	
Commercial Paper	310,900,000	206,400,000
Commercial Paper Weighted Average Interest Rate	0.43%	
Regulated Operations Line of Credit Facilities, Covenant Terms	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.
Ratio of Total Debt to Total Capital	54.00%
Regulated Operations Letters of Credit Outstanding, Amount	11,500,000
Nonregulated Operations Letters of Credit Outstanding, Amount	11,500,000
Nonregulated Operations Line of Credit Facilities, Covenant Terms	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. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million.
Ratio of Liabilities to Tangible Net Worth	0.74 to 1
AEM Net Working Capital	136,200,000
AEM Tangible Net Worth	150,800,000
Debt and Equity Securities Authorized for Issuance	1,300,000,000
Debt Instrument Covenant Description	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.
Debt Instrument Covenant Compliance	We were in compliance with all of our debt covenants
Debt And Equity Securities Available For Issuance	900,000,000
First Facility Regulated Operations [Member]	

Line Of Credit Facility [Line Items]	
Line Of Credit Facility Maximum Borrowing Capacity	750,000,000
Line Of Credit Facility Expiration Date	May 2, 2016
Line Of Credit Facility Interest Rate Description	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
Line Of Credit Facility Amount Outstanding	0
Line of Credit Facility, Current Available Borrowing Capacity	439,100,000
Line of Credit Facility, Maximum Borrowing Capacity with Accordion Feature	1,000,000,000
Second Facility Regulated Operations [Member]	
Line Of Credit Facility [Line Items]	
Line Of Credit Facility Maximum Borrowing Capacity	25,000,000
Line Of Credit Facility Interest Rate Description	a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin
Line Of Credit Facility Amount Outstanding	0
Third Facility Regulated Operations [Member]	
Line Of Credit Facility [Line Items]	
Line Of Credit Facility Maximum Borrowing Capacity	14,000,000
Line Of Credit Facility Expiration Date	September 30, 2013
Line Of Credit Facility Amount Outstanding	0
Intercompany Facility Regulated Operations [Member]	
Line Of Credit Facility [Line Items]	

Line Of Credit Facility Maximum Borrowing Capacity	500,000,000
Line Of Credit Facility Expiration Date	December 31, 2012
Line Of Credit Facility Amount Outstanding	211,500,000
Committed Facility Nonregulated Operations [Member]	
Line Of Credit Facility [Line Items]	
Line Of Credit Facility Maximum Borrowing Capacity	200,000,000
Line Of Credit Facility Interest Rate Description	a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest Federal Funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility
Line Of Credit Facility Amount Outstanding	0
Line of Credit Facility, Current Available Borrowing Capacity	138,500,000
Line of Credit Facility, Maximum Borrowing Capacity with Accordion Feature	500,000,000
Line of Credit Facility, Swing Line Dollar Advance Cap, Higher Available Amount Range	30,000,000
Line of Credit Facility, Swing Line Dollar Advance Cap, Lower Available Amount Range	6,000,000

Intercompany Facility Nonregulated Operations [Member]		
Line Of Credit Facility [Line Items]		
Line Of Credit Facility Maximum Borrowing Capacity	500,000,000	
Line Of Credit Facility Expiration Date	December 31, 2012	
Line Of Credit Facility Interest Rate Description	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	
Line Of Credit Facility Amount Outstanding	0	
Short-term Financing Facility [Member]		
Line Of Credit Facility [Line Items]		
Line Of Credit Facility Maximum Borrowing Capacity	260,000,000	
Line Of Credit Facility Expiration Date	February 1, 2013	
Line Of Credit Facility Amount Outstanding	260,000,000	
Unsecured Notes Due December 2011 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	0	2,303,000
Debt Instrument Interest Rate Stated Percentage	10.00%	
Debt Instrument Maturity Date	Dec. 31, 2011	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	0	2,303,000
Unsecured Senior Notes Due 2013 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	0	250,000,000
Debt Instrument Interest Rate Stated Percentage	5.125%	

Debt Instrument Maturity Date	Jan. 15, 2013	
Debt Instrument, Early Redemption Date	Aug. 28, 2012	
Debt Instrument, Redemption Fee Amount	4,600,000	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	0	250,000,000
Unsecured Senior Notes Due 2014 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	500,000,000	500,000,000
Debt Instrument Interest Rate Stated Percentage	4.95%	
Debt Instrument Maturity Date	Oct. 15, 2014	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	500,000,000	500,000,000
Unsecured Senior Notes Due 2017 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	250,000,000	250,000,000
Debt Instrument Interest Rate Stated Percentage	6.35%	
Debt Instrument Maturity Date	Jun. 15, 2017	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	250,000,000	250,000,000
Unsecured Senior Notes Due 2019 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	450,000,000	450,000,000
Debt Instrument Interest Rate Stated Percentage	8.50%	
Debt Instrument Maturity Date	Mar. 15, 2019	
Long Term Debt By Maturity Abstract		

Total Debt Instrument Carrying Amount	450,000,000	450,000,000
Unsecured Senior Notes Due 2034 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	200,000,000	200,000,000
Debt Instrument Interest Rate Stated Percentage	5.95%	
Debt Instrument Maturity Date	Oct. 15, 2034	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	200,000,000	200,000,000
Unsecured Senior Notes Due 2041 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	400,000,000	400,000,000
Debt Instrument Interest Rate Stated Percentage	5.50%	
Debt Instrument Maturity Date	Jun. 15, 2041	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	400,000,000	400,000,000
Medium Term Notes Due 2025 [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	10,000,000	10,000,000
Debt Instrument Interest Rate Stated Percentage	6.67%	
Debt Instrument Maturity Date	Dec. 15, 2025	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	10,000,000	10,000,000
Unsecured Debentures Due 2028 [Member]		
Debt Instrument [Line Items]		

Debt Instrument Carrying Amount	150,000,000	150,000,000
Debt Instrument Interest Rate Stated Percentage	6.75%	
Debt Instrument Maturity Date	Jul. 15, 2028	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	150,000,000	150,000,000
Rental Property Term Note [Member]		
Debt Instrument [Line Items]		
Debt Instrument Carrying Amount	131,000	262,000
Debt Instrument Maturity Date	Jul. 01, 2013	
Long Term Debt By Maturity Abstract		
Total Debt Instrument Carrying Amount	$ 131,000	$ 262,000

Commitments and Contingencies (Details) (USD $)	12 Months Ended		
	Sep. 30, 2012 Bcf	Sep. 30, 2011	Sep. 30, 2010
Loss Contingency Information About Litigation Matters Abstract			
Description of Pending Litigation	Since April 2009, Atmos Energy and two subsidiaries of AEH, Atmos Energy Marketing, LLC (AEM) and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate. Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases. During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries. A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the		

jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On October 17, 2011, we filed our brief of appellants with the Kentucky Court of Appeals (Court), appealing the verdict of the trial court. The appellees in this case subsequently filed their appellees' brief with the Court on January 16, 2012, with our reply brief being filed with the Court on March 19, 2012. Oral arguments were held in the case on August 27, 2012; however, the Court has yet to render a decision. In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. On March 27, 2012 the court denied the motion to dismiss. Since that time, we have been engaged in discovery activities in this case. We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

Long Term Purchase Commitment [Line Items]

Long Term Purchase Commitment Minimum Quantity Required One To Three Years	29.0			
Long Term Commitment Purchases [Abstract]				
Significant Purchase Commitment Amount Description	$ 978,800,000		$ 1,498,600,000	$ 1,562,800,000
Long Term Purchase Commitment [Abstract]				
Significant Purchase Commitment Remaining Minimum Amount Committed Next Fiscal Year	259,235,000			
Significant Purchase Commitment Remaining Minimum Amount Committed Second Fiscal Year	74,604,000			
Significant Purchase Commitment Remaining Minimum Amount Committed Third Fiscal Year	0			
Significant Purchase Commitment Remaining Minimum Amount Committed Fourth Fiscal Year	0			
Significant Purchase Commitment Remaining Minimum Amount Committed Fifth Fiscal Year	0			
Significant Purchase Commitment Remaining Minimum Amount Committed Thereafter	0			
Total Estimated Purchase Commitments	333,839,000			
Estimated Contractual Demand Fees [Abstract]				
Contractual Demand Fees, Demand Fees Due Next Fiscal Year	19,456,000			
Contractual Demand Fees, Demand Fees Due Second Fiscal Year	10,554,000			

Contractual Demand Fees, Demand Fees Due Third Fiscal Year	4,504,000
Contractual Demand Fees, Demand Fees Due Fourth Fiscal Year	278,000
Contractual Demand Fees, Demand Fees Due Fifth Fiscal Year	37,000
Contractual Demand Fees, Demand Fees Due Thereafter	128,000
Total Estimated Contractual Demand Fees	34,957,000
Loss Contingency, Settlement Agreement, Consideration	In December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines. The Company and the Commission entered into a stipulation and consent agreement, which was approved by the Commission on December 9, 2011, thereby resolving this investigation. The Commission's findings of violations were limited to the nonregulated operations of the Company. Under the terms of the agreement, the Company paid to the United States Treasury a total civil penalty of approximately $6.4 million and to energy assistance programs approximately $5.6 million in disgorgement of unjust profits plus interest for violations identified during the investigation. The resolution of this matter did not have a material adverse impact on the Company's financial position, results of operations or cash flows and none of the payments were charged to any of the Company's customers. In addition, none of the services the Company provides to any of its regulated or nonregulated customers were affected by the agreement.
Steel Service Line Replacement Cost	116,300,000
Inventories Under Indexed Contracts [Member]	
Long Term Purchase Commitment [Line Items]	

Long Term Purchase Commitment Minimum Quantity Required Within One Year	72.2
Long Term Purchase Commitment Minimum Quantity Required After Three Years	29.0
Inventories Under Fixed Price Contracts [Member]	
Long Term Purchase Commitment [Line Items]	
Long Term Purchase Commitment Minimum Quantity Required Within One Year	3.8
Long Term Purchase Commitment Minimum Quantity Required One To Three Years	0.3
Purchase Commitment Amount Minimum	2.46
Purchase Commitment Amount Maximum	$ 6.36

Schedule II - Valuation of Qualifying Accounts	12 Months Ended Sep. 30, 2012
Valuation and Qualifying Accounts [Abstract]	
Schedule Of Valuation And Qualifying Accounts Disclosure Text Block	

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

(1) Uncollectible accounts written off.

Quarterly Financial Information (Details) (USD $) In Thousands, except Per Share data, unless otherwise specified	3 Months Ended								12 Months Ended		
	Sep. 30, 2012	Jun. 30, 2012	Mar. 31, 2012	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010	Sep. 30, 2012	Sep. 30, 2011	Sep. 30, 2010
Discontinued Operations Quarterly Information [Abstract]											
Discontinued Operations Operating Revenues									$ 114,703	$ 141,227	$ 128,630
Discontinued Operations Gross Profit									51,801	57,690	50,805
Disposal Group Including Discontinued Operation Operating Income Loss									27,627	30,328	25,603
Explanatory Disclosure		Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $9.4 million, $5.6 million and $3.2 million, which were not previously reported as discontinued operations.	Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.9 million, $8.5 million and $5.9 million, which were not previously reported as discontinued operations.	Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $17.2 million, $7.5 million and $4.9 million, which were not previously reported as discontinued operations.	Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $9.6 million, $4.9 million and $2.1 million, which were not previously reported as discontinued operations.	Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $10.4 million, $5.2 million and $2.7 million, which were not previously reported as discontinued operations.	Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $25.1 million, $9.2 million and $6.6 million, which were not previously reported as discontinued operations.	Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations from our Georgia operations of $16.0 million, $7.1 million and $4.5 million, which were not previously reported as discontinued operations.			
Operating Revenues by Segment [Line Items]											
Operating revenues	552,566	576,414	1,225,509	1,083,994	779,667	833,168	1,556,374	1,117,226	3,438,483	4,286,435	4,661,060
Selected Quarterly Financial Information Abstract											
Gross profit	249,389	293,171	425,787	355,392	237,160	261,612	444,466	357,582	1,323,739	1,300,820	1,314,136
Operating income	22,791	81,546	202,432	139,471	39,195	31,394	204,624	150,773	446,240	425,986	463,833
Income (loss) from continuing operations	(286)	28,014	102,084	62,384	237	(3,150)	124,293	68,208	192,196	189,588	189,851
Income (loss) from discontinued operations	1,904	3,118	7,027	6,123	1,724	2,584	7,916	5,789	18,172	18,013	15,988
Gain on sale of discountinued operations	6,349	0	0	0					6,349	0	0
Net income (loss)	7,967	31,132	109,111	68,507	1,961	(566)	132,209	73,997	216,717	207,601	205,839
Income (loss) from continuing operations per share - Basic	$ 0.00	$ 0.31	$ 1.12	$ 0.68	$ 0.00	$ (0.04)	$ 1.36	$ 0.75	$ 2.12	$ 2.08	$ 2.05
Income (loss) from discontinued operations per share - Basic	$ 0.09	$ 0.03	$ 0.08	$ 0.07	$ 0.02	$ 0.03	$ 0.09	$ 0.06	$ 0.27	$ 0.20	$ 0.17
Basic net income (loss) per share	$ 0.09	$ 0.34	$ 1.20	$ 0.75	$ 0.02	$ (0.01)	$ 1.45	$ 0.81	$ 2.39	$ 2.28	$ 2.22
Income Loss From Continuing Operations Per Diluted Share	$ 0.00	$ 0.31	$ 1.12	$ 0.68	$ 0.00	$ (0.04)	$ 1.36	$ 0.75	$ 2.10	$ 2.07	$ 2.03

Income (loss) from discontinued operations per share - Diluted	$ 0.09	$ 0.03	$ 0.08	$ 0.07	$ 0.02	$ 0.03	$ 0.09	$ 0.06	$ 0.27	$ 0.20	$ 0.17
Diluted net income (loss) per share	$ 0.09	$ 0.34	$ 1.20	$ 0.75	$ 0.02	$ (0.01)	$ 1.45	$ 0.81	$ 2.37	$ 2.27	$ 2.20
Natural Gas Distribution Segment [Member]											
Operating Revenues by Segment [Line Items]											
Operating revenues	282,516	315,634	871,067	676,113	334,363	396,584	1,052,291	687,426	2,145,330	2,470,664	2,783,863
Selected Quarterly Financial Information Abstract											
Gross profit									1,022,743	1,017,943	998,642
Operating income									304,461	322,088	296,851
Income (loss) from continuing operations									123,848	144,705	109,961
Income (loss) from discontinued operations									18,172	18,013	15,988
Gain on sale of discountinued operations									6,349		
Net income (loss)									148,369	162,718	125,949
Regulated Transmission and Storage Segment [Member]											
Operating Revenues by Segment [Line Items]											
Operating revenues	65,482	67,073	58,037	56,759	61,820	53,570	54,976	49,007	247,351	219,373	203,013
Selected Quarterly Financial Information Abstract											
Gross profit									247,351	219,373	203,013
Operating income									128,824	108,275	97,038
Income (loss) from continuing operations									63,059	52,415	41,486
Income (loss) from discontinued operations									0	0	0
Gain on sale of discountinued operations									0		
Net income (loss)									63,059	52,415	41,486
Nonregulated Segment [Member]											
Operating Revenues by Segment [Line Items]											
Operating revenues	280,114	256,250	370,763	444,176	474,437	491,285	583,531	475,640	1,351,303	2,024,893	2,146,658
Selected Quarterly Financial Information Abstract											
Gross profit									55,124	65,000	114,091
Operating income									12,950	(4,383)	69,944
Income (loss) from continuing operations									5,289	(7,532)	38,404
Income (loss) from discontinued operations									0	0	0
Gain on sale of discountinued operations									0		
Net income (loss)									5,289	(7,532)	38,404
Intersegment Elimination [Member]											
Operating Revenues by Segment [Line Items]											
Operating revenues	(75,546)	(62,543)	(74,358)	(93,054)	(90,953)	(108,271)	(134,424)	(94,847)	(305,501)	(428,495)	(472,474)
Selected Quarterly Financial Information Abstract											
Gross profit									(1,479)	(1,496)	(1,610)
Operating income									5	6	0
Income (loss) from continuing operations									0	0	0
Income (loss) from discontinued operations									0	0	0

Gain on sale of discountinued operations	0		
Net income (loss)	$ 0	$ 0	$ 0

Debt (Table)	**12 Months Ended Sep. 30, 2012**

Debt Tables [Abstract]

Debt instrument table

	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

Debt maturity schedule

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

12. Income Taxes	12 Months Ended Sep. 30, 2012

Income Tax Disclosure Abstract
12. Income Taxes

12. Income Taxes

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

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

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

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2012 and 2011 are presented below:

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

Net deferred tax liabilities	$ (987,993)	$ (883,368)
Deferred credits for rate regulated entities	$ 140	$ 325

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

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

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

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

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We recognized a tax expense of $0.01 million, $0.01 million and $0.5 million related to penalty and interest expenses during the fiscal years ended September 30, 2012, 2011 and 2010.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2007.