ATMOS ENERGY CORP
Form 10-K
November 13, 2013
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended September 30, 2013
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 (IRS employer
incorporation or organization) identification no.)
Three Lincoln Centre, Suite 1800
5430 LBJ Freeway, Dallas, Texas 75240
(Address of principal executive offices) (Zip code)
Registrant's telephone number, including area code:
(972) 934-9227
Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.45) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
(Do not check if a smaller reporting company)
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No þ
The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2013, was $3,816,801,052.
As of November 8, 2013, the registrant had 90,912,251 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 5, 2014 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
AOCI	Accumulated Other Comprehensive Income
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
CFTC	Commodity Futures Trading Commission
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.
GAAP	Generally Accepted Accounting Principles
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
PPA	Pension Protection Act of 2006
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

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PART I

The terms “we,” “our,” “us”, “Atmos Energy” and the “Company” refer to Atmos Energy Corporation and its subsidiaries, unle 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 eight 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.

Over the last two fiscal years, we have sold our natural gas distribution operations in four states to streamline our regulated operations. On April 1, 2013, we completed the divestiture of our natural gas distribution operations in Georgia, representing approximately 64,000 customers, and in August 2012, we completed the sale of our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers.

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

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while operating our business exceptionally well
- invest in our people and infrastructure
- enhance our culture.

We have delivered excellent shareholder value by growing our earnings and increasing our dividends for over 25 consecutive years. Over the last five years, 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.

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Natural Gas Distribution Segment Overview

Our natural gas distribution segment is comprised of our six regulated natural gas distribution divisions. This segment represents approximately 65 percent of our consolidated net income. The following table summarizes key information about these divisions, presented in order of total rate base. See Note 16 in the consolidated financial statements for a description of the completed sales of our Missouri, Illinois, Iowa and Georgia service areas. 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, 2013, we held 998 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.

Division	Service Areas	Communities Served	Customer Meters
Mid-Tex	Texas, including the Dallas/Fort Worth Metroplex	550	1,560,409
Kentucky/Mid-States	Kentucky	230	179,708
	Tennessee		123,590
	Virginia		20,358
Louisiana	Louisiana	300	342,187
West Texas	Amarillo, Lubbock, Midland	80	293,802
Mississippi	Mississippi	110	255,730
Colorado-Kansas	Colorado	170	99,654
	Kansas		136,542

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. Historically, this generally has resulted 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. However, rate design changes implemented during the first quarter of fiscal 2013 in our Mid-Tex and West Texas Divisions should change this trend. The rate design approved in these regulatory proceedings includes an increase to the customer base charge and a decrease in the consumption charge applied to customer usage. The effect of this change in rate design allows our rates to be more closely aligned with the natural gas distribution industry standard rate design. In addition, we anticipate these divisions, which represent approximately 50 percent of the operating income for our natural gas distribution segment, will earn their operating income more ratably over the fiscal year as they are now less dependent on customer consumption.

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. 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 distribution 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 distribution companies 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.

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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.

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 Debt/ Equity Ratio	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	05/01/2011	$807,733	9.36%	50/50	11.80%
Atmos Pipeline — Texas — GRIP	Texas	05/07/2013	979,324	9.36%	N/A	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	50/50	10.25%
	Kansas	09/01/2012	160,075	(2)	(2)	(2)
Kentucky/Mid-States	Kentucky	06/01/2010	221,340(3)	(2)	(2)	(2)
	Tennessee	11/08/2012	201,359	8.28%	49/51	10.10%
	Virginia	11/23/2009	36,861	8.48%	51/49	9.50% - 10.50%
Louisiana	Trans LA	04/01/2013	105,527	7.94%	52/48	10.00% - 10.80%
	LGS	07/01/2013	298,642	8.08%	52/48	10.40%
Mid-Tex Cities	Texas	12/04/2012	1,512,986(4)	8.57%	48/52	10.50%
Mid-Tex — Dallas	Texas	06/01/2013	1,619,429(4)	8.35%	48/52	10.10%
Mississippi	Mississippi	11/01/2012	287,646	8.04%	49/51	9.64%
West Texas(5)	Texas	10/01/2012	271,590	(2)	(2)	(2)

Division	Jurisdiction	Bad Debt Rider(6)	Annual Rate Mechanism	Infrastructure Mechanism	Performance-Based Rate Program(7)	WNA Period
Atmos Pipeline — Texas	Texas	No	No	Yes	N/A	N/A
Colorado-Kansas	Colorado	Yes(8)	No	Yes	No	N/A
	Kansas	Yes	No	Yes	No	October-May
Kentucky/Mid-States	Kentucky	Yes	No	Yes	Yes	November-April
	Tennessee	Yes	No	No	Yes	October-April
	Virginia	Yes	No	Yes	No	January-December
Louisiana	Trans LA	No	Yes	No	No	December-March
	LGS	No	Yes	No	No	December-March
Mid-Tex Cities	Texas	Yes	Yes	Yes	No	November-April
Mid-Tex — Dallas	Texas	Yes	Yes	Yes	No	November-April
Mississippi	Mississippi	No	Yes	No	Yes	November-April
West Texas(5)	Texas	Yes	No	Yes	No	October-May

(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) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $36.6 million included in the October 2012 PRP surcharge. A total of $36.6 million of the Kentucky rate base amount was granted in the annual PRP filing with an effective date of October 1, 2012, an authorized rate of return of 8.74 percent and an authorized

return on equity of 10.50 percent.

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

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(5) On October 2, 2012, a rate case settlement was approved by the Texas Railroad Commission (RRC) that combined the former Amarillo, Lubbock and West Texas jurisdictions into a single "West Texas" jurisdiction.
(6) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.
(7) The performance-based rate program provides incentives to natural gas distribution companies to minimize purchased gas costs by allowing the companies and its customers to share the purchased gas costs savings.
(8) The Company and Commission Staff have agreed to roll the recovery of the gas portion of uncollectible accounts back into base rates as part of the current rate proceeding.

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 2013 were Anadarko Energy Services Company, BP Energy Company, ConocoPhillips Company, Devon Gas Services, L.P., Enterprise Products Operating LLC, Iberdrola Energy Services, LLC, Sequent Energy Management, L.P., Targa Gas Marketing LLC, Tenaska Marketing Ventures, 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 2013 was on January 15, 2013, when sales to customers reached approximately 3.1 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 35 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.

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division (APT). APT is 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. It 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 excess gas. This segment represents approximately 30 percent of our consolidated operations.

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.

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Nonregulated Segment Overview

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation, and represent approximately five percent of our consolidated net income.

AEH's primary business is to buy, sell and deliver natural gas at competitive prices to approximately 1,000 customers located primarily in the Midwest and Southeast areas of the United States. AEH accomplishes this objective by aggregating and purchasing gas supply, arranging transportation and storage logistics and effectively managing commodity price risk.

AEH also earns storage and transportation demand fees primarily from our regulated natural gas distribution operations in Louisiana and Kentucky. These demand fees are subject to regulatory oversight and are renewed periodically.

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 69 percent of our natural gas distribution gross margin.
- Accelerated recovery of capital for approximately 74 percent of our natural gas distribution gross margin.
- Enhanced rate design that allows us to defer certain elements of our cost of service until they are included in rates, such as depreciation, ad valorem taxes and pension costs.
- WNA mechanisms in seven 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, 2013, 2012 and 2011 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 $98.1 million, $30.7 million and $72.4 million, became effective in fiscal 2013, 2012 and 2011, as summarized below:

	Annual Increase to Operating Income For the Fiscal Year Ended September 30		
Rate Action	2013	2012	2011
	(In thousands)		
Infrastructure programs	$30,936	$19,172	$15,033
Annual rate filing mechanisms	9,152	7,044	35,216
Rate case filings	56,700	4,309	20,502
Other ratemaking activity	1,322	167	1,675

	$98,110	$30,692	$72,426

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Additionally, the following ratemaking efforts were initiated during fiscal 2013 but had not been completed as of September 30, 2013:

Division	Rate Action	Jurisdiction	Operating Income Requested (In thousands)
Colorado-Kansas	Rate Case(1)	Colorado	$10,891
Kentucky/Mid-States	Rate Case	Kentucky	13,133
	PRP(2)	Kentucky	2,493
	PRP(2)	Virginia	213
Mid-Tex Division	GRIP(3)	Railroad Commission - Environs	768
	RRM(4)	Mid-Tex Cities	17,077
Mississippi	Stable Rate Filing(5)	Mississippi	—
			$44,575

(1) This rate case seeks a multi-year step increase in annual operating income of $4.5 million on January 1, 2014, $2.9 million on July 1, 2014 and $3.5 million on July 1, 2015.

(2) The Pipeline Replacement Program (PRP) surcharge relates to a long-term program to replace aging infrastructure. The Kentucky and Virginia PRPs were implemented on October 1, 2013.

(3) The Gas Reliability Infrastructure Program (GRIP) surcharge relates to replacing aging infrastructure as well as other changes in net plant. The surcharge is calculated on a system-wide basis, but is only filed with the Railroad Commission for unincorporated areas served by the Mid-Tex Division.

(4) The Rate Review Mechanism (RRM) is an annual rate filing mechanism that allows us to refresh our rates on a periodic basis without filing a formal rate case. The current RRM program was approved by the Mid-Tex Cities in the summer of 2013. The first filing under the mechanism was made in July of 2013 and has been settled for $12.5 million to be implemented on November 1, 2013.

(5) The Stable Rate Filing shows no deficiency, thus no change in operating income is anticipated from the current year filing.

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Our recent ratemaking activity is discussed in greater detail below.

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 divisions 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, Kansas, Kentucky and Virginia. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2013, 2012 and 2011:

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2013 Infrastructure Programs:				
Atmos Pipeline — Texas	12/2012	$156,440	$26,730	05/07/2013
Colorado-Kansas — Kansas	09/2012	5,376	601	01/09/2013
Kentucky/Mid-States — Georgia[(1)(2)]	09/2011	6,519	1,079	10/01/2012
Kentucky/Mid-States — Kentucky[(2)]	09/2013	19,296	2,425	10/01/2012
Kentucky/Mid-States — Virginia	09/2013	756	101	10/01/2012
Total 2013 Infrastructure Programs		$188,387	$30,936	
2012 Infrastructure Programs:				
Mid-Tex Unincorporated (Environs)[(3)]	12/2011	$145,671	$744	06/26/2012
Atmos Pipeline — Texas	12/2011	87,210	14,684	04/10/2012
Kentucky/Mid-States — Georgia[(1)(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[(4)]	09/2010	2,367	277	02/14/2011
Kentucky/Mid-States — Georgia[(1)(2)]	09/2009	5,359	764	10/01/2010
Total 2011 Infrastructure Programs		$209,552	$15,033	

(1) On April 1, 2013, we completed the sale of our Georgia operations to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. The increase in operating income arising from the implementation of new rates is included as a component of discontinued operations through March 31, 2013.

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

(3) 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.

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

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Annual Rate Filing Mechanisms

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

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income (In thousands)		Effective Date
2013 Filings:					
Louisiana	LGS	12/31/2012	$908		07/01/2013
Mid-Tex	City of Dallas	9/30/2012	1,800		06/01/2013
Louisiana	TransLa	9/30/2012	2,260		04/01/2013
Kentucky/Mid-States	Georgia[1]	9/30/2013	743		02/01/2013
Mississippi	Mississippi	6/30/2012	3,441		11/01/2012
Total 2013 Filings			$9,152		
2012 Filings:					
Louisiana	LGS	12/31/2011	$2,324		07/01/2012
Mid-Tex	Dallas	9/30/2011	1,204		06/01/2012
Louisiana	Trans La	9/30/2011	11		04/01/2012
Kentucky/Mid-States	Georgia[1]	9/30/2011	(818	)	02/01/2012
Mississippi	Mississippi	6/30/2011	4,323		01/11/2012
Total 2012 Filings			$7,044		
2011 Filings:					
Mid-Tex	Mid-Tex 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	9/30/2010	350		04/01/2011
Mid-Tex	Mid-Tex Cities	12/31/2009	23,122		10/01/2010
Total 2011 Filings			$35,216		

(1) On April 1, 2013, we completed the sale of our Georgia operations to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. The increase in operating income arising from the implementation of new rates is included as a component of discontinued operations through March 31, 2013.

From 2008 through fiscal 2011, the Mid-Tex Division had an annual rate review mechanism (RRM) for approximately 80 percent of its customers, which allowed it to update rates annually without the necessity of filing a general rate case. In fiscal 2013, a new RRM was approved for these customers.

Since June 2011, the Mid-Tex Division has operated under a Dallas Annual Rate Review Mechanism (DARR) that provides the ability for it to annually update rates for its City of Dallas customers without the necessity of filing a general rate case. 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 with operations in Texas 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 until the expenses are included in rates, including the recording of interest on the deferred expenses.

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Rate Case Filings

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

Division	State	Increase in Annual Operating Income (In thousands)	Effective Date
2013 Rate Case Filings:			
Mid-Tex	Texas	$42,601	12/04/2012
Kentucky/Mid-States	Tennessee	7,530	11/08/2012
West Texas	Texas	6,569	10/01/2012
Total 2013 Rate Case Filings		$56,700	
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	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2013, 2012 and 2011:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income (In thousands)	Effective Date
2013 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem(1)	$1,322	02/01/2013
Total 2013 Other Rate Activity			$1,322	
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	

(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 and 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

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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. The FERC also has 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, 2013, we had 4,720 employees, consisting of 4,611 employees in our regulated operations and 109 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 2013, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any

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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:

The Company is dependent on continued access to the credit and capital markets to execute our business strategy.
Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation, Moody's Investors Services, Inc. and Fitch Ratings, Ltd. Similar to most companies, we rely upon access to both short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions were to cause a significant limitation on our access to the private and public capital 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 private credit and/or public capital markets and increase our costs of borrowing.

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 an intercompany lending facility between AEH and Atmos Energy to finance its working capital needs, supplemented by two small credit facilities with outside lenders. Our ability to provide this liquidity to AEH for our nonregulated operations is limited by the terms of the lending arrangement with AEH, which is 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 deterioration of current conditions in the credit and capital markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

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 regulatory oversight from various state and local regulatory authorities in the eight states that we serve. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by the appropriate regulatory authorities or other third-party intervenors. In the normal course of business, a regulated entity often needs to place assets in service and establish historical test periods before rate cases that seek to adjust our allowed returns to recover that investment can be filed. Further, the regulatory review process can be lengthy. Because of this process, we 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." The regulatory process also involves the risk that regulatory authorities may (i) review our purchases of natural gas and adjust the amount of our gas costs that we pass through to our customers or (ii) limit the costs we may have incurred from our cost of service that can be recovered from customers.

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 several 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 continuing to improve economic conditions, including the continued 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.

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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.

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

We are subject to market risks beyond our control, including market liquidity, commodity price volatility caused by market supply and demand dynamics and counterparty creditworthiness and interest rate risk. Our regulated operations are generally insulated from commodity price risk through its purchased gas cost mechanisms. With respect to interest rate risk, we have been operating in a relatively low interest-rate environment in recent years compared to historical norms for both short and long-term interest rates. However, increases in interest rates could adversely affect our future financial results.

Although our nonregulated operations represent approximately five percent of our consolidated results, commodity price volatility experienced in this business segment could lead to some volatility in our earnings. 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.

Although we manage our business to maintain no open positions related to our physical storage, there are times when limited net open positions 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. 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. Further, if the local physical markets 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.

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.

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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.

Finally, 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 from competitors who offer lower cost, basic services.

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 in our natural gas distribution business, 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.

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 rules issued by the RRC's Division of Public Safety that require natural gas distribution companies to develop and implement risk-based programs 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.

The costs of providing health care benefits, pension and postretirement health care benefits and related funding requirements may increase substantially.

We provide health care benefits and a cash-balance pension plan and postretirement health care benefits to eligible full-time employees. The costs of providing health care benefits to our employees could significantly increase over time due to rapidly increasing health care inflation, the impact of the Health Care Reform Act of 2010 (HCR) and any future legislative changes related to the provision of health care benefits. Although the HCR is not expected to have a direct material impact when a number of its more significant provisions become effective in 2014, the impact of costs incurred by the insurance industry arising from the implementation of HCR on the Company are difficult to measure at this time.

The costs of providing a cash-balance pension plan and postretirement health care benefits to eligible full-time employees and related funding requirements could be influenced by changes in the market value of the assets funding our pension and postretirement health care plans. Any significant declines in the value of these investments could increase the costs of our

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pension and postretirement health care 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.

The costs to the Company of providing these 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.

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 72,000 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 eight 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, natural gas distribution and pipeline companies are facing increasing federal, state and local oversight of the safety of their operations. Although we believe these costs should be ultimately recoverable through our rates, the 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. 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 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.

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

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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.

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. Even though we have insurance coverage in place for many of these cyber-related risks, if such an attack or act of terrorism were to occur, our operations and 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, 2013, in our natural gas distribution segment, we owned an aggregate of 67,146 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. Through our regulated transmission and storage segment we owned 5,628 miles of gas transmission and gathering lines as well as 110 miles of gas transmission and gathering lines through our nonregulated segment.

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, 2013:

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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
Total	9,893,590	11,065,200	20,958,790	198,100
Regulated Transmission and Storage Segment — Texas	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated Segment				
Kentucky	3,438,900	3,240,000	6,678,900	67,500
Louisiana	438,583	300,973	739,556	56,000
Total	3,877,483	3,540,973	7,418,456	123,500
Total	59,914,299	30,484,198	90,398,497	1,556,600

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

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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, 2013:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Natural Gas Distribution Segment			
	Colorado-Kansas Division	4,261,909	108,489
	Kentucky/Mid-States Division	11,081,603	344,706
	Louisiana Division	2,736,539	161,393
	Mid-Tex Division	1,000,000	75,000
	Mississippi Division	3,695,429	162,402
	West Texas Division	3,375,000	106,000
Total		26,150,480	957,990
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		35,851,349	1,276,434

(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 10 to the consolidated financial statements.

ITEM 4. Mine Safety Disclosures.

Not applicable.

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 2013 and 2012 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:

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	Fiscal 2013			Fiscal 2012		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$36.86	$33.20	$0.35	$35.40	$30.97	$0.345
March 31	42.69	35.11	0.35	33.15	30.60	0.345
June 30	44.87	38.59	0.35	35.07	30.91	0.345
September 30	45.19	39.40	0.35	36.94	34.94	0.345
			$1.40			$1.38

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, 2013 was 16,746. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2013 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 S&P 500 Stock Index and the cumulative total return of a customized peer company group, the Comparison Company Index. The Comparison Company Index 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, 2008 in our common stock, the S&P 500 Index and in the common stock of the companies in the Comparison Company Index, as well as a reinvestment of dividends paid on such investments throughout the period.

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

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	Cumulative Total Return					
	9/30/2008	9/30/2009	9/30/2010	9/30/2011	9/30/2012	9/30/2013
Atmos Energy Corporation	100.00	111.68	121.63	140.75	161.81	199.54
S&P 500	100.00	93.09	102.55	103.72	135.05	161.17
Peer Group	100.00	98.11	130.03	153.00	184.92	217.15

The Comparison Company Index contains a hybrid group of utility companies, primarily natural gas distribution companies, recommended by our independent executive 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 following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2013.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	7,930	$ 25.96	1,403,439
Total equity compensation plans approved by security holders	7,930	25.96	1,403,439
Equity compensation plans not approved by security holders	—	—	—
Total	7,930	$ 25.96	1,403,439

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 fiscal 2013. At September 30, 2013, 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				
	2013	2012[(1)]	2011[(1)]	2010	2009[(1)]
	(In thousands, except per share data)				
Results of Operations					
Operating revenues	$3,886,257	$3,438,483	$4,286,435	$4,661,060	$4,793,248
Gross profit	$1,412,050	$1,323,739	$1,300,820	$1,314,136	$1,297,682
Income from continuing operations	$230,698	$192,196	$189,588	$189,851	$175,026
Net income	$243,194	$216,717	$207,601	$205,839	$190,978
Diluted income per share from continuing operations	$2.50	$2.10	$2.07	$2.03	$1.90
Diluted net income per share	$2.64	$2.37	$2.27	$2.20	$2.07
Cash dividends declared per share	$1.40	$1.38	$1.36	$1.34	$1.32

Financial Condition					
Net property, plant and equipment[2]	$6,030,655	$5,475,604	$5,147,918	$4,793,075	$4,439,103
Total assets	$7,940,401	$7,495,675	$7,282,871	$6,763,791	$6,367,083
Capitalization:					
Shareholders' equity	$2,580,409	$2,359,243	$2,255,421	$2,178,348	$2,176,761
Long-term debt (excluding current maturities)	2,455,671	1,956,305	2,206,117	1,809,551	2,169,400
Total capitalization	$5,036,080	$4,315,548	$4,461,538	$3,987,899	$4,346,161

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(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”, “stra
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; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; the impact of adverse economic conditions on our customers; the effects of inflation and changes in the availability and price of natural gas; market risks beyond our control affecting our risk management activities, including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in Texas; increased competition from energy suppliers and alternative forms of energy; adverse weather conditions; the capital-intensive nature of our gas distribution business; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; 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 inherent hazards and risks involved in operating our gas distribution business; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; 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

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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.

Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
Regulation	Our natural gas distribution and regulated transmission and storage operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the United States. Accordingly, the financial results for these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject. 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. 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. 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.	Decisions of regulatory authorities Issuance of new regulations Assessing the probability of the recoverability of deferred costs
Unbilled Revenue	We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues attributable 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.	Estimates of delivered sales volumes based on actual tariff information and weather information and estimates of customer consumption and/or behavior Estimates of purchased gas costs related to estimated deliveries Estimates of uncollectible amounts billed subject to refund

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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 methodology 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	General economic and market conditions Assumed investment returns by asset class Assumed future salary increases Projected timing of future cash disbursements Health care cost experience trends Participant demographic information Actuarial mortality assumptions Impact of legislation

	retirement is estimated based upon our annual review of our participant census information as of the measurement date.	
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 uncollectible receivables, lawsuits, claims made by third parties or the action of various regulatory agencies. We recognize these contingencies in our consolidated financial statements when we determine, based on currently available facts and circumstances it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. 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 10 to our consolidated financial statements.	Currently available facts Management's estimate of future resolution

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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 12 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. The recognition of the changes in fair value of these financial instruments 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. Our accounting elections for financial instruments and hedging activities utilized are more fully described in Note 12 to the consolidated financial statements. 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. Finally, changes in the effectiveness of the hedge relationship could impact the accounting treatment.	Designation of contracts under the hedge accounting rules Judgment in the application of accounting guidance Assessment of the probability that future hedged transactions will occur Changes in market conditions and the related impact on the fair value of the hedged item and the associated designated financial instrument Changes in the effectiveness of the hedge relationship
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). The fair value of our financial instruments is subject to potentially significant volatility based on numerous considerations including, but not limited to changes in commodity prices, interest rates, maturity and settlement of these financial instruments. 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	General economic and market conditions Volatility in underlying market conditions Maturity dates of financial instruments Creditworthiness of our counterparties Creditworthiness of Atmos Energy Impact of credit risk mitigation activities on the assessment of the creditworthiness of Atmos Energy and its counterparties

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 financial instruments represent the best information available with respect to the market in which transactions involving these financial instruments are executed, the closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts.

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.

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Critical Accounting Policy	Summary of Policy	Factors Influencing Application of the Policy
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 U.S. 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 affect these estimates, which could result in an impairment charge.	General economic and market conditions Projected timing and amount of future discounted cash flows Judgment in the evaluation of relevant data

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. Historically, this has generally resulted 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 54 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. However, we believe rate design changes implemented during the first quarter of fiscal 2013 in our Mid-Tex and West Texas Divisions should continue to cause this pattern to change. The rate design approved in these regulatory proceedings includes an increase to the customer base charge and a decrease in the consumption charge applied to customer usage. The effect of this change in rate design should result in a more equal distribution of operating income earned over the fiscal year for approximately 50 percent of our natural gas distribution segment.

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 2013, we earned $243.2 million, or $2.64 per diluted share, which represents a twelve percent increase in net income and diluted net income per share over fiscal 2012, primarily due to recent improvements in rate designs in our natural gas distribution and regulated transmission and storage segments combined with a two percent year-over-year increase in consolidated natural gas distribution throughput due to colder weather.

We completed the sale of our Georgia natural gas distribution operations on April 1, 2013 to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million pursuant to a purchase agreement executed on August 8, 2012. In connection with the sale, we recognized a net of tax gain of $5.3 million. Accordingly, the results of operations for this service area are shown in discontinued operations for all periods presented. Prior-year results also reflect our Illinois, Iowa and Missouri service areas in discontinued operations. The sale of these three service areas was completed in August 2012.

We also took several steps during the year ended September 30, 2013 to further strengthen our balance sheet and borrowing capability. In December 2012, we amended our $750 million revolving credit agreement primarily to (i) increase our borrowing capacity to $950 million while retaining the accordion feature that would allow an increase in borrowing capacity up to $1.2 billion and (ii) to permit same-day funding on base rate loans. In August 2013, we amended our revolving credit agreement primarily to increase the term through August 2018. We also terminated Atmos Energy Marketing’s $200 million committed and secured credit facility and replaced this facility with two $25 million 364-day bilateral facilities, which should result in a decrease in external credit expense incurred in our nonregulated operations. After giving effect to these changes, we have over $1 billion of working capital funding from four committed revolving credit facilities and one noncommitted revolving credit facility.

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On January 11, 2013, we issued $500 million of 4.15% 30-year unsecured senior notes, which replaced, on a long-term basis, our $250 million 5.125% 10-year unsecured senior notes we redeemed in August 2012. The net proceeds of approximately $494 million were used to repay $260 million outstanding under the short-term financing facility used to redeem our 5.125% senior notes and to partially repay commercial paper borrowings and for general corporate purposes.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2013, 2012 and 2011.

	For the Fiscal Year Ended September 30		
	2013	2012	2011
	(In thousands, except per share data)		
Operating revenues	$3,886,257	$3,438,483	$4,286,435
Gross profit	1,412,050	1,323,739	1,300,820
Operating expenses	910,171	877,499	874,834
Operating income	501,879	446,240	425,986
Miscellaneous income (expense)	(197)	(14,644)	21,184
Interest charges	128,385	141,174	150,763
Income from continuing operations before income taxes	373,297	290,422	296,407
Income tax expense	142,599	98,226	106,819
Income from continuing operations	230,698	192,196	189,588
Income from discontinued operations, net of tax	7,202	18,172	18,013
Gain on sale of discontinued operations, net of tax	5,294	6,349	—
Net income	$243,194	$216,717	$207,601
Diluted net income per share from continuing operations	$2.50	$2.10	$2.07
Diluted net income per share from discontinued operations	$0.14	$0.27	$0.20
Diluted net income per share	$2.64	$2.37	$2.27

Regulated operations contributed 95 percent, 97 percent and 104 percent to our consolidated net income from continuing operations for fiscal years 2013, 2012 and 2011. 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		
	2013	2012	2011
	(In thousands)		
Natural gas distribution segment	$150,856	$123,848	$144,705
Regulated transmission and storage segment	68,260	63,059	52,415
Nonregulated segment	11,582	5,289	(7,532)
Net income from continuing operations	230,698	192,196	189,588
Net income from discontinued operations	12,496	24,521	18,013
Net income	$243,194	$216,717	$207,601

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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		
	2013	2012	2011
	(In thousands, except per share data)		
Regulated operations	$219,116	$186,907	$197,120
Nonregulated operations	11,582	5,289	(7,532)
Net income from continuing operations	230,698	192,196	189,588
Net income from discontinued operations	12,496	24,521	18,013
Net income	$243,194	$216,717	$207,601
Diluted EPS from continuing regulated operations	$2.38	$2.04	$2.15
Diluted EPS from nonregulated operations	0.12	0.06	(0.08)
Diluted EPS from continuing operations	2.50	2.10	2.07
Diluted EPS from discontinued operations	0.14	0.27	0.20
Consolidated diluted EPS	$2.64	$2.37	$2.27

We reported net income of $243.2 million, or $2.64 per diluted share for the year ended September 30, 2013, compared with net income of $216.7 million or $2.37 per diluted share in the prior year. Income from continuing operations was $230.7 million, or $2.50 per diluted share compared with $192.2 million, or $2.10 per diluted share in the prior-year period. Income from discontinued operations was $12.5 million or $0.14 per diluted share for the year, which includes the gain on sale of substantially all our assets in Georgia of $5.3 million, compared with $24.5 million or $0.27 per diluted share in the prior year. Unrealized gains in our nonregulated operations during the current year increased net income by $5.3 million or $0.05 per diluted share compared with net losses recorded in the prior year of $5.0 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In fiscal 2012, net income included the net positive impact of several one-time items totaling $10.3 million, or $0.11 per diluted share related to the pre-tax items, which are discussed in further detail below. In fiscal 2013, net income includes an $8.2 million ($5.3 million, net of tax), or $0.06 per diluted share, favorable impact related to the gain recorded in association with the April 1, 2013 completion of the sale of our Georgia assets.

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 fiscal 2011. 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 fiscal 2011. 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 fiscal 2011. Unrealized losses in our nonregulated operations during fiscal 2012 reduced net income by $5.0 million or $0.05 per diluted share compared with net losses recorded in fiscal 2011 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 pre-tax items. In fiscal 2012, net income included 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 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.

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

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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 receipt taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenue 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.
Although the cost of gas typically does not have a direct impact on our gross profit, 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.
We completed the sale of our Georgia natural gas distribution operations on April 1, 2013 to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million. In connection with the sale, we recognized a net of tax gain of $5.3 million. On August 1, 2012, we completed the sale of substantially all of our natural gas distribution operations in Missouri, Illinois and Iowa.

During fiscal 2013, we completed 13 regulatory proceedings, which should result in a $71.4 million increase in annual operating income. The majority of this rate increase related to our Mid-Tex Division, where rates became effective January 1, 2013. The rate design approved in our Mid-Tex Division and West Texas Division regulatory proceedings includes an increase to the base customer charge and a decrease in the commodity charge applied to customer consumption. The effect of this change in rate design allows the Company’s rates to be more closely aligned with the utility industry standard rate design. In addition, we anticipate these divisions will earn their operating income more ratably over the fiscal year as they are now less dependent on customer consumption.

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Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands, unless otherwise noted)				
Gross profit	$1,081,236	$1,022,743	$1,017,943	$58,493	$4,800
Operating expenses	738,143	718,282	695,855	19,861	22,427
Operating income	343,093	304,461	322,088	38,632	(17,627)
Miscellaneous income (expense)	2,535	(12,657)	16,242	15,192	(28,899)
Interest charges	98,296	110,642	115,740	(12,346)	(5,098)
Income from continuing operations before income taxes	247,332	181,162	222,590	66,170	(41,428)
Income tax expense	96,476	57,314	77,885	39,162	(20,571)
Income from continuing operations	150,856	123,848	144,705	27,008	(20,857)
Income from discontinued operations, net of tax	7,202	18,172	18,013	(10,970)	159
Gain on sale of discontinued operations, net of tax	5,649	6,349	—	(700)	6,349
Net Income	$163,707	$148,369	$162,718	$15,338	$(14,349)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	269,162	244,466	275,540	24,696	(31,074)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	123,144	128,222	125,812	(5,078)	2,410
Consolidated natural gas distribution throughput from continuing operations — MMcf	392,306	372,688	401,352	19,618	(28,664)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	4,731	18,295	22,668	(13,564)	(4,373)
Total consolidated natural gas distribution throughput — MMcf	397,037	390,983	424,020	6,054	(33,037)
Consolidated natural gas distribution average transportation revenue per Mcf	$0.46	$0.43	$0.47	$0.03	$(0.04)
Consolidated natural gas distribution average cost of gas per Mcf sold	$4.91	$4.64	$5.30	$0.27	$(0.66)

Fiscal year ended September 30, 2013 compared with fiscal year ended September 30, 2012

The $58.5 million period-over-period increase in natural gas distribution gross profit primarily reflects the following:

- $25.7 million increase in our Mid-Tex and West Texas divisions associated with the rate design changes implemented in the fiscal first quarter.
- $16.1 million increase in rates in our Kentucky/Mid-States, Mississippi, Colorado-Kansas and Louisiana divisions.
- $7.5 million increase due to colder weather, primarily in the Mississippi, Kentucky/Mid-States and Colorado-Kansas divisions.
- $5.9 million increase in revenue-related taxes in our Mid-Tex and West Texas service areas primarily due to higher revenues on which the tax is calculated.
- $4.5 million increase in transportation revenues.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased by $19.9 million, primarily due to the following:

- $12.2 million increase in employee-related expenses due to lower labor capitalization rates, increased benefit costs and increased variable compensation expense.

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- $11.7 million increase primarily associated with higher line locate activities, pipeline and right-of-way maintenance spending to improve the safety and reliability of our system.
- $5.0 million increase in taxes, other than income due to higher revenue-related taxes, as discussed above.
- $6.8 million increase in bad debt expense primarily attributable to an increase in revenue arising from the rate design changes and the temporary suspension of active customer collection activities following the implementation of a new customer information system during the third fiscal quarter.

These increases were partially offset by:

- $6.9 million decrease in legal and other administrative costs.
- $6.4 million decrease in depreciation expense due to new depreciation rates approved in the most recent Mid-Tex rate case that went into effect in January 2013.
- $2.4 million gain realized on the sale of certain investments.

Miscellaneous income increased $15.2 million, primarily due to the absence of a $10.0 million one-time donation to a donor advised fund in the prior year, the completion of a periodic review of our performance-based ratemaking (PBR) mechanism in our Tennessee service area and the implementation of a new PBR program in our Mississippi Division during fiscal 2013.

Interest charges decreased $12.3 million, primarily from interest deferrals associated with our infrastructure spending activities in Texas.

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 fiscal 2011 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 fiscal 2011.
- $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 fiscal 2011 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 fiscal 2012.

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

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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.

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, 2013, 2012 and 2011. 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				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands)				
Mid-Tex	$158,900	$142,755	$144,204	$16,145	$(1,449)
Kentucky/Mid-States	46,164	32,185	37,593	13,979	(5,408)
Louisiana	52,125	48,958	50,442	3,167	(1,484)
West Texas	28,085	27,875	29,686	210	(1,811)
Mississippi	29,112	27,369	26,338	1,743	1,031
Colorado-Kansas	25,478	23,898	25,920	1,580	(2,022)
Other	3,229	1,421	7,905	1,808	(6,484)
Total	$343,093	$304,461	$322,088	$38,632	$(17,627)

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.

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Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$179,628	$162,808	$125,973	$16,820	$36,835
Third-party transportation	66,939	64,158	73,676	2,781	(9,518)
Storage and park and lend services	5,985	6,764	7,995	(779)	(1,231)
Other	16,348	13,621	11,729	2,727	1,892
Gross profit	268,900	247,351	219,373	21,549	27,978
Operating expenses	129,047	118,527	111,098	10,520	7,429
Operating income	139,853	128,824	108,275	11,029	20,549
Miscellaneous income (expense)	(2,285)	(1,051)	4,715	(1,234)	(5,766)
Interest charges	30,678	29,414	31,432	1,264	(2,018)
Income before income taxes	106,890	98,359	81,558	8,531	16,801
Income tax expense	38,630	35,300	29,143	3,330	6,157
Net income	$68,260	$63,059	$52,415	$5,201	$10,644
Gross pipeline transportation volumes — MMcf	649,740	640,732	620,904	9,008	19,828
Consolidated pipeline transportation volumes — MMcf	467,178	466,527	435,012	651	31,515

Fiscal year ended September 30, 2013 compared with fiscal year ended September 30, 2012

The $21.5 million increase in regulated transmission and storage gross profit compared to the prior-year period was primarily a result of the Gas Reliability Infrastructure Program (GRIP) filings approved by the Railroad Commission of Texas (RRC) during fiscal 2012 and 2013. During fiscal 2012, the RRC approved the Atmos Pipeline - Texas GRIP filing with an annual operating income increase of $14.7 million, effective April 2012. On May 7, 2013, the RRC approved the Atmos Pipeline - Texas GRIP filing with an annual operating income increase of $26.7 million that went into effect with bills rendered on and after May 7, 2013. GRIP filings increased period-over-period gross profit by $19.7 million.

This increase was partially offset by a $10.5 million increase in operating expenses largely attributable to increased depreciation expense as a result of increased capital investments and increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system.

The APT rate case approved by the RRC on April 18, 2011 contained an annual adjustment mechanism, approved for a three-year pilot program, that adjusted regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit. The annual adjustment mechanism expired on June 30, 2013. APT requested to extend the annual adjustment mechanism until November 1, 2017. A hearing to review the request was held on October 29, 2013 with a final decision expected in December 2013.

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 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.

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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 fiscal 2011 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).

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and represent approximately five percent of our consolidated net income.

AEH's primary business is to buy, sell and deliver natural gas at competitive prices to approximately 1,000 customers located primarily in the Midwest and Southeast areas of the United States. AEH accomplishes this objective by aggregating and purchasing gas supply, arranging transportation and storage logistics and effectively managing commodity price risk.

AEH also earns storage and transportation demand fees primarily from our regulated natural gas distribution operations in Louisiana and Kentucky. These demand fees are subject to regulatory oversight and are renewed periodically.

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 buying, selling and delivering natural gas 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.
- Increased or decreased 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. 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.

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Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the fiscal years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$39,839	$46,578	$58,990	$(6,739)	$(12,412)
Storage and transportation services	14,641	13,382	14,570	1,259	(1,188)
Other	(103)	3,179	1,841	(3,282)	1,338
Total realized margins	54,377	63,139	75,401	(8,762)	(12,262)
Unrealized margins	8,954	(8,015)	(10,401)	16,969	2,386
Gross profit	63,331	55,124	65,000	8,207	(9,876)
Operating expenses, excluding asset impairment	44,404	36,886	39,113	7,518	(2,227)
Asset impairment	—	5,288	30,270	(5,288)	(24,982)
Operating income (loss)	18,927	12,950	(4,383)	5,977	17,333
Miscellaneous income	2,316	1,035	657	1,281	378
Interest charges	2,168	3,084	4,015	(916)	(931)
Income (loss) from continuing operations before income taxes	19,075	10,901	(7,741)	8,174	18,642
Income tax expense (benefit)	7,493	5,612	(209)	1,881	5,821
Income (loss) from continuing operations	11,582	5,289	(7,532)	6,293	12,821
Loss on sale of discontinued operations, net of tax	(355)	—	—	(355)	—
Net income (loss)	$11,227	$5,289	$(7,532)	$5,938	$12,821
Gross nonregulated delivered gas sales volumes — MMcf	396,561	400,512	446,903	(3,951)	(46,391)
Consolidated nonregulated delivered gas sales volumes — MMcf	343,669	351,628	384,799	(7,959)	(33,171)
Net physical position (Bcf)	12.0	18.8	21.0	(6.8)	(2.2)

Fiscal year ended September 30, 2013 compared with fiscal year ended September 30, 2012

Gross profit increased $8.2 million for the year ended September 30, 2013 compared to the prior year. Realized margins decreased $8.8 million, primarily attributable to lower gas delivery margins. Consolidated sales volumes decreased two percent due to increased competition which reduced industrial and power generation sales. The impact of lower sales volumes was compounded by a decrease in per-unit margins from 11.6 cents per Mcf to 10.0 cents per Mcf. This decrease was offset by an increase of $17.0 million in unrealized margins, primarily due to the year-over-year timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses increased $7.5 million, primarily due to increased litigation and software support costs, partially offset by reduced employee costs.

Miscellaneous income increased $1.3 million primarily due to a gain realized from the sale of a peaking power facility and related assets during the first quarter of fiscal 2013.

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

Realized margins for gas delivery, storage and transportation services and other services were $63.1 million during the year ended September 30, 2012 compared with $75.4 million for fiscal 2011. The decrease reflects the following:

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- 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.

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Unrealized margins increased $2.4 million in fiscal 2012 compared to fiscal 2011 primarily due to the year-over-year timing of realized margins on the settlement of hedged natural gas inventory positions.

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 fiscal 2011, 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.

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 (i) have sufficient liquidity for our short-term and long-term needs in a cost-effective manner and (ii) maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

The following table presents our capitalization as of September 30, 2013 and 2012:

	September 30					
	2013			2012		
	(In thousands, except percentages)					
Short-term debt	$367,984	6.8	%	$570,929	11.7	%
Long-term debt	2,455,671	45.4	%	1,956,436	40.0	%
Shareholders' equity	2,580,409	47.8	%	2,359,243	48.3	%
Total capitalization, including short-term debt	$5,404,064	100.0	%	$4,886,608	100.0	%

Total debt as a percentage of total capitalization, including short-term debt, was 52.2 percent and 51.7 percent at September 30, 2013 and 2012.

On January 11, 2013, we issued $500 million of 4.15% 30-year unsecured senior notes, which, in effect, replaced our $250 million 5.125% 10-year unsecured senior notes we redeemed in August 2012, on a long-term basis. The net proceeds of approximately $494 million were used to repay $260 million outstanding under our short-term financing facility used to redeem our 5.125% senior notes and to partially repay commercial paper borrowings and for general corporate purposes.

Going forward, we anticipate our capital spending will be more consistent with levels experienced during fiscal 2013 as we continue to invest in the safety and reliability of our distribution and transportation system. We plan to continue to fund our growth and maintain a balanced capital structure through the use of long-term debt securities and, to a lesser extent, equity.

Further, $500 million of long-term debt will mature in October 2014. We plan to issue new senior notes to replace this maturing debt. During the current year, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with this anticipated issuance at 3.129%. 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 2014.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These factors 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.

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Cash flows from operating, investing and financing activities for the years ended September 30, 2013, 2012 and 2011 are presented below.

	For the Fiscal Year Ended September 30				
	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
	(In thousands)				
Total cash provided by (used in)					
Operating activities	$613,127	$586,917	$582,844	$26,210	$4,073
Investing activities	(696,914)	(609,260)	(627,386)	(87,654)	18,126
Financing activities	85,747	(44,837)	44,009	130,584	(88,846)
Change in cash and cash equivalents	1,960	(67,180)	(533)	69,140	(66,647)
Cash and cash equivalents at beginning of period	64,239	131,419	131,952	(67,180)	(533)
Cash and cash equivalents at end of period	$66,199	$64,239	$131,419	$1,960	$(67,180)

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, 2013 compared with fiscal year ended September 30, 2012

For the fiscal year ended September 30, 2013, we generated operating cash flow of $613.1 million from operating activities compared with $586.9 million in the prior year. The year-over-year increase reflects changes in working capital offset by a $10.5 million decrease in contributions made to our pension and postretirement plans in the current year.

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 fiscal 2011. The year-over-year increase reflects changes in working capital offset by a $56.7 million increase in contributions made to our pension and postretirement plans during fiscal 2012.

Cash flows from investing activities

Our ongoing capital expenditure 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 and enhance the integrity of our pipelines. In recent years, we have increased our level of capital spending to improve the safety and reliability of our distribution system and to expand our intrastate pipeline network. Over the last three fiscal years, approximately 68 percent of our capital spending has been committed to improving the safety and reliability of our system.

Over the next five years, we anticipate our capital spending will be more consistent with levels experienced during fiscal 2013 as we continue to invest in the safety and reliability of our distribution and transportation system. Where possible, we will also continue to focus 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.

For the fiscal year ended September 30, 2013, we incurred $845.0 million for capital expenditures compared with $732.9 million for the fiscal year ended September 30, 2012 and $623.0 million for the fiscal year ended September 30, 2011.

Fiscal Year ended September 30, 2013 compared with fiscal year ended September 30, 2012

The $112.1 million increase in capital expenditures in fiscal 2013 compared to fiscal 2012 primarily reflects spending incurred for the Line W and Line WX expansion projects and increased cathodic protection spending in our regulated transmission and storage segment.

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

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.

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Cash flows from financing activities

We received a net $85.7 million and $44.0 million in cash from financing activities for fiscal years 2013 and 2011. In fiscal 2012, we used a net $44.8 million in financing activities. Our significant financing activities for the fiscal years ended September 30, 2013, 2012 and 2011 are summarized as follows:

2013

During the fiscal year ended September 30, 2013, our financing activities generated $85.7 million of cash compared with $44.8 million of cash used in the prior year. Current year cash flows from financing activities were significantly influenced by the issuance of $500 million 4.15% 30-year unsecured senior notes on January 11, 2013. We used a portion of the net cash proceeds of $493.8 million to repay a $260 million short-term financing facility executed in fiscal 2012, to settle, for $66.6 million, three Treasury Locks associated with the issuance and to reduce short-term debt borrowings by $167.2 million.

2012

During the fiscal year ended September 30, 2012, our financing activities used $44.8 million of cash, primarily due to the payment of $257.0 million associated with the early redemption of our $250 million 5.125% Senior notes that were scheduled to mature in January 2013. The repayment of our $250 million 5.125% Senior notes was financed using a $260 million short-term loan. Additionally, we repurchased $12.5 million of common stock under our 2011 share repurchase program.

2011

During the fiscal year ended September 30, 2011, our financing activities generated $44.0 million of cash, primarily related to the issuance of $400 million 5.50% Senior Notes in June 2011 and the related settlement of three Treasury locks for $20.1 million. We used a portion of the net cash proceeds of $394.5 million to pay scheduled long-term debt repayments, including our $350 million 7.375% senior notes that were paid on their maturity date in May 2011. Additionally, we received $27.8 million cash in March 2011 related to the unwinding of two Treasury locks.

The following table shows the number of shares issued for the fiscal years ended September 30, 2013, 2012 and 2011:

	For the Fiscal Year Ended September 30		
	2013	2012	2011
Shares issued:			
1998 Long-term incentive plan	531,672	482,289	675,255
Outside directors stock-for-fee plan	2,088	2,375	2,385
Total shares issued	533,760	484,664	677,640

The increase in the number of shares issued in fiscal 2013 compared with the number of shares issued in fiscal 2012 primarily reflects the type of awards that were issued from the 1998 Long-Term Incentive Plan (LTIP). In the current year, employees were issued restricted stock units, for which we issued new shares. In the prior year, employees were issued restricted stock awards, which were held in trust and did not require the issuance of new shares. During fiscal 2013, we canceled and retired 133,449 shares attributable to federal withholdings on equity awards which are not included in the table above. At September 30, 2013, of the 8.7 million shares authorized for issuance from the LTIP, 1.4 million shares remained available.

The decreased number of shares issued in fiscal 2012 compared with the number of shares issued in fiscal 2011 primarily reflects the exercise of a significant number of stock options during fiscal 2011. During fiscal 2012, we canceled 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.

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 $950 million commercial paper program, which is collateralized by our $950 million unsecured credit facility, as well as three additional committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. As a result, we have approximately $1 billion of working capital funding. Additionally, our $950 million unsecured credit facility has an accordion feature, which, if utilized, would increase borrowing capacity to $1.2 billion. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities.

Shelf Registration

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On March 28, 2013, we filed a registration statement with the Securities and Exchange Commission to issue, from time to time, up to $1.75 billion in common stock and/or debt securities available for issuance, which replaced our registration statement that expired on March 31, 2013. As of September 30, 2013, $1.75 billion was available under the shelf registration statement.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our regulated and nonregulated businesses and the regulatory 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	A-	Baa1	A-
Commercial paper	A-2	P-2	F-2

On October 8, 2013, S&P upgraded our senior unsecured debt rating to A- from BBB+, with a ratings outlook of stable, citing an improved business risk profile from an increasing contribution of earnings from our regulated operations and focusing our nonregulated operations on our delivered gas business.

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, 2013. Our debt covenants are described in Note 5 to the consolidated financial statements.

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Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2013.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In thousands)		
Contractual Obligations					
Long-term debt[1]	$2,460,000	$—	$500,000	$250,000	$1,710,000
Short-term debt[1]	367,984	367,984	—	—	—
Interest charges[2]	1,918,491	144,317	240,097	218,585	1,315,492
Gas purchase commitments[3]	230,480	230,480	—	—	—
Capital lease obligations[4]	822	186	372	264	—
Operating leases[4]	166,802	16,722	30,276	30,131	89,673
Demand fees for contracted storage[5]	6,088	4,196	1,252	284	356
Demand fees for contracted transportation[6]	13,098	8,466	4,604	28	—
Financial instrument obligations[7]	7,676	1,543	6,133	—	—
Pension and postretirement benefit plan contributions[8]	411,623	67,687	101,176	82,976	159,784
Uncertain tax positions (including interest)[9]	3,172	—	3,172	—	—
Total contractual obligations	$5,586,236	$841,581	$887,082	$582,268	$3,275,305

(1) See Note 5 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, 2013.

(4) See Note 9 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, 2013. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled.

(8) Represents expected contributions to our pension and postretirement benefit plans, which are discussed in Note 6 to the consolidated financial statements.

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

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, 2013 are reflected in the table above.

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, 2013, AEH was committed to purchase 78.0 Bcf within one year, 21.9 Bcf within one to three years and 1.0 Bcf after three years under indexed contracts. AEH is committed to purchase 6.1 Bcf within one year and 0.2 Bcf within one to three years under fixed price contracts with prices ranging from $3.32 to $6.36 per Mcf.

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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 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, 2013 (in thousands):

Fair value of contracts at September 30, 2012	$(76,260	)
Contracts realized/settled	2,590	
Fair value of new contracts	3,077	
Other changes in value	180,241	
Fair value of contracts at September 30, 2013	$109,648	

The fair value of our natural gas distribution segment's financial instruments at September 30, 2013, is presented below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at September 30, 2013 Maturity in years				
	Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$294	$109,354	$—	$—	$109,648
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$294	$109,354	$—	$—	$109,648

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, 2013 (in thousands):

Fair value of contracts at September 30, 2012	$(15,123	)
Contracts realized/settled	(245	)
Fair value of new contracts	—	
Other changes in value	668	
Fair value of contracts at September 30, 2013	(14,700	)
Netting of cash collateral	24,829	
Cash collateral and fair value of contracts at September 30, 2013	$10,129	

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The fair value of our nonregulated segment's financial instruments at September 30, 2013, is presented below by time period and fair value source.

Fair Value of Contracts at September 30, 2013