ATMOS ENERGY CORP
Form 10-Q
February 04, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended December 31, 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 (State or other jurisdiction of incorporation or organization)	75-1743247 (IRS employer identification no.)
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas (Address of principal executive offices)	75240 (Zip code)

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

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

Large Accelerated Filer 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 Exchange Act) Yes ¨ No þ

Number of shares outstanding of each of the issuer's classes of common stock, as of January 31, 2014.

Class	Shares Outstanding
No Par Value	90,958,751

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
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody’s	Moody’s Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor’s Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2013 (Unaudited)	September 30, 2013
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$7,861,741	$7,722,019
Less accumulated depreciation and amortization	1,708,778	1,691,364
Net property, plant and equipment	6,152,963	6,030,655
Current assets		
Cash and cash equivalents	194,563	66,199
Accounts receivable, net	661,213	301,992
Gas stored underground	286,542	244,741
Other current assets	157,252	64,201
Total current assets	1,299,570	677,133
Goodwill	741,363	741,363
Deferred charges and other assets	422,195	485,117
	$8,616,091	$7,934,268
CAPITALIZATION AND LIABILITIES		
Shareholders’ equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2013 — 90,958,302 shares; September 30, 2013 — 90,640,211 shares	$455	$453
Additional paid-in capital	1,769,516	1,765,811
Retained earnings	828,311	775,267
Accumulated other comprehensive income	63,032	38,878
Shareholders’ equity	2,661,314	2,580,409
Long-term debt	1,955,750	2,455,671
Total capitalization	4,617,064	5,036,080
Current liabilities		
Accounts payable and accrued liabilities	458,198	241,611
Other current liabilities	365,508	368,891
Short-term debt	689,795	367,984
Current maturities of long-term debt	500,000	—
Total current liabilities	2,013,501	978,486
Deferred income taxes	1,230,052	1,164,053
Regulatory cost of removal obligation	356,617	359,299
Pension and postretirement liabilities	359,534	358,787
Deferred credits and other liabilities	39,323	37,563
	$8,616,091	$7,934,268

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2013	2012
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$843,865	$666,787
Regulated transmission and storage segment	71,341	60,681
Nonregulated segment	447,721	399,894
Intersegment eliminations	(107,779)	(93,207)
	1,255,148	1,034,155
Purchased gas cost		
Natural gas distribution segment	544,694	387,156
Regulated transmission and storage segment	—	—
Nonregulated segment	429,155	377,435
Intersegment eliminations	(107,658)	(92,798)
	866,191	671,793
Gross profit	388,957	362,362
Operating expenses		
Operation and maintenance	115,757	106,527
Depreciation and amortization	60,469	59,579
Taxes, other than income	42,011	41,334
Total operating expenses	218,237	207,440
Operating income	170,720	154,922
Miscellaneous income (expense)	(2,132)	698
Interest charges	32,115	30,522
Income from continuing operations before income taxes	136,473	125,098
Income tax expense	49,457	47,750
Income from continuing operations	87,016	77,348
Income from discontinued operations, net of tax ($0 and $1,728)	—	3,117
Net income	$87,016	$80,465
Basic earnings per share		
Income per share from continuing operations	$0.96	$0.85
Income per share from discontinued operations	—	0.04
Net income per share — basic	$0.96	$0.89
Diluted earnings per share		
Income per share from continuing operations	$0.95	$0.85
Income per share from discontinued operations	—	0.03
Net income per share — diluted	$0.95	$0.88
Cash dividends per share	$0.37	$0.35
Weighted average shares outstanding:		
Basic	90,833	90,359
Diluted	91,746	91,309

See accompanying notes to condensed consolidated financial statements.

4

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended December 31	
	2013	2012
	(Unaudited) (In thousands)	
Net income	$87,016	$80,465
Other comprehensive income (loss), net of tax		
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $1,435 and $(220)	2,394	(373)
Cash flow hedges:		
Amortization and unrealized gain on interest rate agreements, net of tax of $8,013 and $7,049	13,942	12,264
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $4,999 and $(233)	7,818	(365)
Total other comprehensive income	24,154	11,526
Total comprehensive income	$111,170	$91,991

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2013	2012
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$87,016	$80,465
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	60,469	60,500
Charged to other accounts	221	128
Deferred income taxes	47,127	45,951
Other	5,228	3,242
Net assets / liabilities from risk management activities	(5,477)	(15,641)
Net change in operating assets and liabilities	(160,284)	(144,787)
Net cash provided by operating activities	34,300	29,858
Cash Flows From Investing Activities		
Capital expenditures	(180,567)	(190,027)
Other, net	(5,867)	(1,273)
Net cash used in investing activities	(186,434)	(191,300)
Cash Flows From Financing Activities		
Net increase in short-term debt	320,783	256,933
Cash dividends paid	(33,984)	(31,992)
Repurchase of equity awards	(6,289)	(3,124)
Other	(12)	(13)
Net cash provided by financing activities	280,498	221,804
Net increase in cash and cash equivalents	128,364	60,362
Cash and cash equivalents at beginning of period	66,199	64,239
Cash and cash equivalents at end of period	$194,563	$124,601

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2013

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. For the fiscal year ended September 30, 2013, our regulated businesses generated approximately 95 percent of our consolidated net income.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which at December 31, 2013, covered service areas located in eight states. On April 1, 2013, we completed the divestiture of our natural gas distribution operations in Georgia, representing approximately 64,000 customers. In addition, we transport natural gas for others through our distribution system. Our regulated businesses also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

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

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.

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. In the opinion of management, all material adjustments (consisting of normal recurring accruals) necessary for a fair presentation have been made to the unaudited consolidated interim-period financial statements. These consolidated interim-period financial statements are condensed as permitted by the instructions to Form 10-Q and should be read in conjunction with the audited consolidated financial statements of Atmos Energy Corporation included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2013 are not indicative of our results of operations for the full 2014 fiscal year, which ends September 30, 2014.

Except as noted in Note 5, no events have occurred subsequent to the balance sheet date that would require recognition or disclosure in the condensed consolidated financial statements.

Significant accounting policies

Our accounting policies are described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013.

Certain prior-year amounts have been reclassified to conform with the current-year presentation.

Due to the April 1, 2013 sale of our Georgia distribution operations, prior year financial results for this service area are shown in discontinued operations.

During the three months ended December 31, 2013, there were no new accounting standards announced that will become applicable to the Company in future periods. Disclosure requirements for offsetting arrangements for financial instruments became effective for us beginning on October 1, 2013. We have presented these disclosures in Note 8. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the three months ended December 31, 2013.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of December 31, 2013 and September 30, 2013 included the following:

	December 31, 2013	September 30, 2013
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs(1)	$180,512	$187,977
Merger and integration costs, net	5,120	5,250
Deferred gas costs	8,630	15,152
Regulatory cost of removal asset	9,998	10,008
Rate case costs	5,806	6,329
Texas Rule 8.209(2)	31,838	30,364
APT annual adjustment mechanism	5,773	5,853
Recoverable loss on reacquired debt	20,796	21,435
Other	4,480	4,380
	$272,953	$286,748
Regulatory liabilities:		
Deferred gas costs	$50,094	$16,481
Deferred franchise fees	4,792	1,689
Regulatory cost of removal obligation	425,028	427,524
Other	9,788	7,887
	$489,702	$453,581

(1) Includes $18.2 million and $17.4 million of pension and postretirement expense deferred pursuant to regulatory authorization.

(2) Texas Rule 8.209 is a Railroad Commission rule that allows for the deferral of all expenses associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recovered through base rates.

Currently authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years.

3. Segment Information

As discussed in Note 1 above, 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 is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three month periods ended December 31, 2013 and 2012 by segment are presented in the following tables:

	Three Months Ended December 31, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$842,432	$21,170	$391,546	$—	$1,255,148
Intersegment revenues	1,433	50,171	56,175	(107,779)	—
	843,865	71,341	447,721	(107,779)	1,255,148
Purchased gas cost	544,694	—	429,155	(107,658)	866,191
Gross profit	299,171	71,341	18,566	(121)	388,957
Operating expenses					
Operation and maintenance	89,663	17,300	8,915	(121)	115,757
Depreciation and amortization	49,551	9,786	1,132	—	60,469
Taxes, other than income	37,084	4,663	264	—	42,011
Total operating expenses	176,298	31,749	10,311	(121)	218,237
Operating income	122,873	39,592	8,255	—	170,720
Miscellaneous income (expense)	(471)	(1,181)	324	(804)	(2,132)
Interest charges	23,325	8,957	637	(804)	32,115
Income before income taxes	99,077	29,454	7,942	—	136,473
Income tax expense	36,320	10,008	3,129	—	49,457
Net income	$62,757	$19,446	$4,813	$—	$87,016
Capital expenditures	$127,506	$52,921	$140	$—	$180,567

	Three Months Ended December 31, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$665,549	$18,699	$349,907	$—	$1,034,155
Intersegment revenues	1,238	41,982	49,987	(93,207)	—
	666,787	60,681	399,894	(93,207)	1,034,155
Purchased gas cost	387,156	—	377,435	(92,798)	671,793
Gross profit	279,631	60,681	22,459	(409)	362,362
Operating expenses					
Operation and maintenance	83,736	16,320	6,882	(411)	106,527
Depreciation and amortization	50,060	8,390	1,129	—	59,579
Taxes, other than income	36,751	3,949	634	—	41,334
Total operating expenses	170,547	28,659	8,645	(411)	207,440
Operating income	109,084	32,022	13,814	2	154,922
Miscellaneous income (expense)	(131)	(127)	1,667	(711)	698
Interest charges	23,563	6,871	797	(709)	30,522
Income from continuing operations before income taxes	85,390	25,024	14,684	—	125,098
Income tax expense	32,297	8,919	6,534	—	47,750
Income from continuing operations	53,093	16,105	8,150	—	77,348
Income from discontinued operations, net of tax	3,117	—	—	—	3,117
Net income	$56,210	$16,105	$8,150	$—	$80,465
Capital expenditures	$145,871	$43,831	$325	$—	$190,027

Balance sheet information at December 31, 2013 and September 30, 2013 by segment is presented in the following tables.

	December 31, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$4,799,657	$1,293,093	$60,213	$—	$6,152,963
Investment in subsidiaries	863,214	—	(2,096)	(861,118)	—
Current assets					
Cash and cash equivalents	152,058	—	42,505	—	194,563
Assets from risk management activities	88,934	—	9,001	—	97,935
Other current assets	740,359	11,184	564,079	(308,550)	1,007,072
Intercompany receivables	793,589	—	—	(793,589)	—
Total current assets	1,774,940	11,184	615,585	(1,102,139)	1,299,570
Intangible assets	—	—	110	—	110
Goodwill	574,190	132,462	34,711	—	741,363
Noncurrent assets from risk management activities	45,878	—	2,614	—	48,492
Deferred charges and other assets	345,075	20,960	7,558	—	373,593
	$8,402,954	$1,457,699	$718,695	$(1,963,257)	$8,616,091
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,661,314	$415,868	$447,346	$(863,214)	$2,661,314
Long-term debt	1,955,750	—	—	—	1,955,750
Total capitalization	4,617,064	415,868	447,346	(863,214)	4,617,064
Current liabilities					
Current maturities of long-term debt	500,000	—	—	—	500,000
Short-term debt	972,795	—	—	(283,000)	689,795
Liabilities from risk management activities	36	—	—	—	36
Other current liabilities	645,433	20,429	181,262	(23,454)	823,670
Intercompany payables	—	719,438	74,151	(793,589)	—
Total current liabilities	2,118,264	739,867	255,413	(1,100,043)	2,013,501
Deferred income taxes	916,095	299,819	14,138	—	1,230,052
Regulatory cost of removal obligation	356,617	—	—	—	356,617
Pension and postretirement liabilities	359,534	—	—	—	359,534
Deferred credits and other liabilities	35,380	2,145	1,798	—	39,323
	$8,402,954	$1,457,699	$718,695	$(1,963,257)	$8,616,091

	September 30, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$4,719,873	$1,249,767	$61,015	$—	$6,030,655
Investment in subsidiaries	831,136	—	(2,096)	(829,040)	—
Current assets					
Cash and cash equivalents	4,237	—	61,962	—	66,199
Assets from risk management activities	1,837	—	10,129	—	11,966
Other current assets	428,366	11,709	452,126	(293,233)	598,968
Intercompany receivables	783,738	—	—	(783,738)	—
Total current assets	1,218,178	11,709	524,217	(1,076,971)	677,133
Intangible assets	—	—	121	—	121
Goodwill	574,190	132,462	34,711	—	741,363
Noncurrent assets from risk management activities	109,354	—	—	—	109,354
Deferred charges and other assets	347,687	19,227	8,728	—	375,642
	$7,800,418	$1,413,165	$626,696	$(1,906,011)	$7,934,268
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,580,409	$396,421	$434,715	$(831,136)	$2,580,409
Long-term debt	2,455,671	—	—	—	2,455,671
Total capitalization	5,036,080	396,421	434,715	(831,136)	5,036,080
Current liabilities					
Current maturities of long-term debt	—	—	—	—	—
Short-term debt	645,984	—	—	(278,000)	367,984
Liabilities from risk management activities	1,543	—	—	—	1,543
Other current liabilities	491,681	20,288	110,306	(13,316)	608,959
Intercompany payables	—	712,768	70,970	(783,738)	—
Total current liabilities	1,139,208	733,056	181,276	(1,075,054)	978,486
Deferred income taxes	871,360	283,554	8,960	179	1,164,053
Regulatory cost of removal obligation	359,299	—	—	—	359,299
Pension and postretirement liabilities	358,787	—	—	—	358,787
Deferred credits and other liabilities	35,684	134	1,745	—	37,563
	$7,800,418	$1,413,165	$626,696	$(1,906,011)	$7,934,268

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three months ended December 31, 2013 and 2012 are calculated as follows:

	Three Months Ended December 31	
	2013	2012
	(In thousands, except per share amounts)	
Basic Earnings Per Share from continuing operations		
Income from continuing operations	$87,016	$77,348
Less: Income from continuing operations allocated to participating securities	235	260
Income from continuing operations available to common shareholders	$86,781	$77,088
Basic weighted average shares outstanding	90,833	90,359
Income from continuing operations per share — Basic	$0.96	$0.85
Basic Earnings Per Share from discontinued operations		
Income from discontinued operations	$—	$3,117
Less: Income from discontinued operations allocated to participating securities	—	10
Income from discontinued operations available to common shareholders	$—	$3,107
Basic weighted average shares outstanding	90,833	90,359
Income from discontinued operations per share — Basic	$—	$0.04
Net income per share — Basic	$0.96	$0.89

	Three Months Ended December 31	
	2013	2012
	(In thousands, except per share amounts)	
Diluted Earnings Per Share from continuing operations		
Income from continuing operations available to common shareholders	$86,781	$77,088
Effect of dilutive stock options and other shares	1	2
Income from continuing operations available to common shareholders	$86,782	$77,090
Basic weighted average shares outstanding	90,833	90,359
Additional dilutive stock options and other shares	913	950
Diluted weighted average shares outstanding	91,746	91,309
Income from continuing operations per share — Diluted	$0.95	$0.85
Diluted Earnings Per Share from discontinued operations		
Income from discontinued operations available to common shareholders	$—	$3,107
Effect of dilutive stock options and other shares	—	—
Income from discontinued operations available to common shareholders	$—	$3,107
Basic weighted average shares outstanding	90,833	90,359
Additional dilutive stock options and other shares	913	950
Diluted weighted average shares outstanding	91,746	91,309
Income from discontinued operations per share — Diluted	$—	$0.03
Net income per share — Diluted	$0.95	$0.88

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three months ended December 31, 2013 and 2012 as their exercise price was less than the average market price of the common stock during those periods.

2011 Share Repurchase Program

We did not repurchase any shares during the three months ended December 31, 2013 and 2012 under our 2011 share repurchase program.

5. Debt

The nature and terms of our debt instruments and credit facilities are described in detail in Note 5 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. Except as noted below, there were no material changes in the terms of our debt instruments during the three months ended December 31, 2013.

Long-term debt
Long-term debt at December 31, 2013 and September 30, 2013 consisted of the following:

	December 31, 2013	September 30, 2013
	(In thousands)	
Unsecured 4.95% Senior Notes, due October 2014	$500,000	$500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Unsecured 4.15% Senior Notes, due 2043	500,000	500,000
Medium-term note Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Total long-term debt	2,460,000	2,460,000
Less:		
Original issue discount on unsecured senior notes and debentures	4,250	4,329
Current maturities	500,000	—
	$1,955,750	$2,455,671

Short-term debt
Our short-term debt is utilized to fund ongoing working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity and capital expenditures. Our short-term borrowing requirements are affected primarily by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.
We currently finance our short-term borrowing requirements through a combination of a $950 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1.0 billion of working capital funding. At December 31, 2013 and September 30, 2013, a total of $689.8 million and $368.0 million was outstanding under our commercial paper program.
Regulated Operations
We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $985 million of working capital funding, including a five-year $950 million unsecured facility with an accordion feature, which, if utilized would increased the borrowing capacity to $1.2 billion, a $25 million unsecured facility and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.1 million at December 31, 2013.
In addition to these third-party facilities, our regulated operations have a $500 million intercompany revolving credit facility with AEH, which bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or (ii) the rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2014.
Nonregulated Operations
Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, had two $25 million 364-day bilateral credit facilities that expired in December 2013. The $25 million 364-day uncommitted bilateral facility was extended to December 2014. The $25 million committed bilateral facility was replaced with a $15 million committed 364-day bilateral credit facility. These facilities are used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under these bilateral credit facilities was $15.4 million at December 31, 2013. On January 29, 2014, the $25 million 364-day uncommitted bilateral facility was amended to temporarily increase the amount available under this facility to $50 million to address the increase in volumes and prices driven by colder than

normal weather this winter-heating season. The maximum available under the facility will return to $25 million on June 30, 2014.

AEH has a $500 million intercompany demand credit facility with AEC. This facility bears interest at a rate equal to the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2014.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.75 billion in common stock and/or debt securities. As of December 31, 2013, $1.75 billion was available under the shelf registration statement.

Debt Covenants

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2013, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 56 percent. In addition, both the interest margin and the fee that we pay on unused amounts under certain of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these financial covenants, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers. Additionally, our public debt indentures relating to our senior notes and debentures, as well as certain of our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

We were in compliance with all of our debt covenants as of December 31, 2013. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

6. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2013 and 2012 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense. On October 2, 2013, due to the retirement of one of our executives, we recognized a settlement loss of $4.5 million associated with our Supplemental Executive Benefits Plan (SEBP). In association with the retirement, on October 2, 2013, we made a $16.8 million benefit payment from the SEBP.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2013	2012	2013	2012
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$4,738	$5,202	$4,196	$4,700
Interest cost	6,824	6,025	3,988	3,241
Expected return on assets	(5,901)	(5,739)	(1,292)	(997)
Amortization of transition obligation	—	—	68	270
Amortization of prior service credit	(34)	(35)	(363)	(362)
Amortization of actuarial loss	3,932	5,561	158	1,049
Settlement loss	4,539	—	—	—
Net periodic pension cost	$14,098	$11,014	$6,755	$7,901

17

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2013 and 2012 are as follows:

	Pension Benefits		Other Benefits	
	2013	2012	2013	2012
Discount rate	4.95 %	4.04 %	4.95 %	4.04 %
Rate of compensation increase	3.50 %	3.50 %	N/A	N/A
Expected return on plan assets	7.25 %	7.75 %	4.60 %	4.70 %

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2014. During the first three months of fiscal 2014, we contributed $4.7 million to our defined benefit plans and we anticipate contributing approximately $10 million to $15 million during the remainder of the fiscal year.

We contributed $5.9 million to our other post-retirement benefit plans during the three months ended December 31, 2013. We expect to contribute a total of approximately $15 million to $20 million to these plans during the remainder of the fiscal year.

7. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 10 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2013.

Kentucky Litigation

Since April 2009, Atmos Energy and two subsidiaries of AEH, Atmos Energy Marketing, LLC (AEM) and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate. Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

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

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

In an opinion handed down on January 25, 2013, the Court of Appeals overturned the $28.5 million jury verdict returned against the Atmos Entities. In a unanimous decision by a three-judge panel, the Court of Appeals reversed the claims asserted by the landowners and investors/working interest owners. The Court of Appeals concluded that all of such claims that the Atmos Entities appealed should have been dismissed by the trial court as a matter of law. The Court of Appeals let stand the jury verdict on one claim that Atmos Energy and our subsidiaries chose not to appeal, which was a trespass claim. The jury had awarded a total of $10,000 in compensatory damages to one landowner on that claim. The Court of Appeals vacated all of the other damages awarded by the jury and remanded the case to the trial court for a new trial, solely on the issue of whether punitive damages should be awarded to that landowner and, if so, in what amount.

The investors/working interest owners, on February 25, 2013, and the landowners, on March 19, 2013, each filed with the Supreme Court of Kentucky, separate motions for discretionary review of the opinion of the Court of Appeals. We filed a response to the motion filed by the investors/working owners on March 27, 2013 and to the landowners' motion on April 17, 2013. The decision of the Court of Appeals will not become final until the appellate process is completed. We had previously accrued what we believed to be an adequate amount for the anticipated resolution of this matter and we will continue to maintain this amount in legal reserves until the appellate process in this case has been completed. We continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Tennessee Business License Tax

Atmos Energy, through its affiliate, AEM, has been involved in a dispute with the Tennessee Department of Revenue (TDOR) regarding sales business tax audits over a period of several years. AEM has challenged the assessment of the business tax. With respect to certain issues, AEM and the TDOR filed competing Partial Motions for Summary Judgment with the Chancery Court. On August 2, 2013, the Chancery Court granted the TDOR's Partial Motion for Summary Judgment and denied AEM's Partial Motion for Summary Judgment and set February 1, 2014 as the date by which AEM and the TDOR will set a date for filing any cross motions for partial summary judgment as to the remaining issue. The Company anticipates a decision by the Chancery Court on the remaining issue in fiscal 2014.

The cumulative assessment is expected to be approximately $11 million for the period December 2002 through December 2013, including tax, interest and penalties. We have accrued what we believe to be an adequate amount for the anticipated resolution of this matter and we will continue to review and if appropriate adjust this reserve until this matter is resolved. We continue to believe the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

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

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At December 31, 2013, AEH was committed to purchase 91.1 Bcf within one year, 14.8 Bcf within one to three years and 0.9 Bcf after three years under indexed contracts. AEH is committed to purchase 4.4 Bcf within one year under fixed price contracts with prices ranging from $3.60 to $6.36 per Mcf. Purchases under these contracts totaled $350.2 million and $289.5 million for the three months ended December 31, 2013 and 2012.

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

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. There were no material changes to the estimated storage and transportation fees for the three months ended December 31, 2013.

Regulatory Matters

Various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, continue to adopt regulations implementing many of the provisions of the Dodd-Frank Act of 2010. We continue to enact new procedures and modify existing business practices and contractual arrangements to comply with such regulations. Additional rulemakings are pending which we believe will result in new reporting and disclosure obligations. The costs associated with hedging certain risks inherent in our business may be further increased when these expected additional regulations are adopted.

As of December 31, 2013, rate cases were in progress in our Colorado, Kentucky and West Texas service areas, annual rate filing mechanisms were in progress in Louisiana and Mississippi and an infrastructure program filing and ad valorem filing were in progress in Kansas. These regulatory proceedings are discussed in further detail below in Management’s Discussion and Analysis — Recent Ratemaking Developments.

8. Financial Instruments

We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. During the three months ended December 31, 2013 there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

Regulated Commodity Risk Management Activities

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

Our natural gas distribution gas supply department is responsible for executing this segment’s commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2013-2014 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 39 percent, or 24.8 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

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

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

not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.
We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 52 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in asset optimization activities in our nonregulated segment.
Our nonregulated operations also use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges for accounting purposes.
Interest Rate Risk Management Activities
We periodically manage interest rate risk by entering into financial instruments to fix the Treasury yield component of the interest cost associated with anticipated financings.
As of December 31, 2013, we have forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, which we designated as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the forward starting interest rate swaps are being recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred is reported as a component of interest expense.
In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. As of December 31, 2013, the remaining amortization periods for the settled Treasury locks extend through fiscal 2043.

Quantitative Disclosures Related to Financial Instruments
The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.
As of December 31, 2013, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2013, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated	
		Quantity (MMcf)		
Commodity contracts	Fair Value	—	(18,585	)
	Cash Flow	—	31,500	
	Not designated	15,796	59,095	
		15,796	72,010	

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of December 31, 2013 and September 30, 2013. The gross amounts of recognized assets and liabilities are netted within our unaudited Condensed Consolidated Balance Sheets to the extent that we have netting arrangements with the counterparties.

	Balance Sheet Location	Natural Gas Distribution Assets	Natural Gas Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
December 31, 2013					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$—	$—	$12,238	$(12,089)
Interest rate contracts	Other current assets / Other current liabilities	83,578	—	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	783	(983)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	44,833	—	—	—
Total		128,411	—	13,021	(13,072)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	5,356	(36)	55,288	(63,144)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	1,045	—	35,740	(32,926)
Total		6,401	(36)	91,028	(96,070)
Gross Financial Instruments		134,812	(36)	104,049	(109,142)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(101,435)	101,435
Net Financial Instruments		134,812	(36)	2,614	(7,707)
Cash collateral		—	—	9,001	7,707
Net Assets/Liabilities from Risk Management Activities		$134,812	$(36)	$11,615	$—

22

	Balance Sheet Location	Natural Gas Distribution Assets	Natural Gas Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2013					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$—	$—	$9,094	$(12,173)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	416	(1,639)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	107,512	—	—	—
Total		107,512	—	9,510	(13,812)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	1,837	(1,543)	65,388	(70,876)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	1,842	—	40,982	(45,892)
Total		3,679	(1,543)	106,370	(116,768)
Gross Financial Instruments		111,191	(1,543)	115,880	(130,580)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(115,875)	115,875
Net Financial Instruments		111,191	(1,543)	5	(14,705)
Cash collateral		—	—	10,124	14,705
Net Assets/Liabilities from Risk Management Activities		$111,191	$(1,543)	$10,129	$—

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended December 31, 2013 and 2012 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $5.1 million and $16.1 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three months ended December 31, 2013 and 2012 is presented below.

	Three Months Ended December 31 2013	2012
	(In thousands)	
Commodity contracts	$(8,561)	$7,314
Fair value adjustment for natural gas inventory designated as the hedged item	13,779	8,818
Total decrease in purchased gas cost	$5,218	$16,132

The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$(620)	$(241)
Timing ineffectiveness	5,838	16,373
	$5,218	$16,132

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost. To the extent that the Company's natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or market.

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 2013 and 2012 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended December 31, 2013		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$(2,609)	$(2,609)
Loss arising from ineffective portion of commodity contracts	—	(119)	(119)
Total impact on purchased gas cost	—	(2,728)	(2,728)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,058)	—	(1,058)
Total Impact from Cash Flow Hedges	$(1,058)	$(2,728)	$(3,786)

	Three Months Ended December 31, 2012		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$(5,160)	$(5,160)
Loss arising from ineffective portion of commodity contracts	—	(19)	(19)
Total impact on purchased gas cost	—	(5,179)	(5,179)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(502)	—	(502)
Total Impact from Cash Flow Hedges	$(502)	$(5,179)	$(5,681)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 2013 and 2012. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended December 31	
	2013	2012
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate agreements	$13,270	$11,945
Forward commodity contracts	6,226	(3,513)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate agreements	672	319
Forward commodity contracts	1,592	3,148
Total other comprehensive income from hedging, net of tax[1]	$21,760	$11,899

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

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our interest rate agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred gains (losses) associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 2013. However, the table below does not include the expected recognition in earnings of our outstanding interest rate agreements as those instruments have not yet settled.

	Interest Rate Agreements	Commodity Contracts	Total
	(In thousands)		
Next twelve months	$(2,343)	$3,458	$1,115
Thereafter	(27,350)	(116)	(27,466)
Total[1]	$(29,693)	$3,342	$(26,351)

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

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended December 31, 2013 and 2012 was a decrease in gross profit of $0.8 million and $0.1 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

9. Accumulated Other Comprehensive Income

We record deferred gains (losses) in accumulated other comprehensive income (AOCI) related to available-for-sale securities, interest rate agreement cash flow hedges and commodity contract cash flow hedges. Deferred gains (losses) for our available-for-sale securities and commodity contract cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate agreement cash flow hedges are recognized in earnings as they are amortized. The following tables provide the components of our accumulated other comprehensive income (loss) balances, net of the related tax effects allocated to each component of other comprehensive income.

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2013	$5,448	$37,906	$(4,476)	$38,878
Other comprehensive income before reclassifications	2,394	13,270	6,226	21,890
Amounts reclassified from accumulated other comprehensive income	—	672	1,592	2,264
Net current-period other comprehensive income	2,394	13,942	7,818	24,154
December 31, 2013	$7,842	$51,848	$3,342	$63,032

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2012	$5,661	$(44,273)	$(8,995)	$(47,607)
Other comprehensive income before reclassifications	(373)	11,945	(3,513)	8,059
Amounts reclassified from accumulated other comprehensive income	—	319	3,148	3,467
Net current-period other comprehensive income	(373)	12,264	(365)	11,526
December 31, 2012	$5,288	$(32,009)	$(9,360)	$(36,081)

The following tables detail reclassifications out of AOCI for the three months ended December 31, 2013 and 2012. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended December 31, 2013	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$(1,058)	Interest charges
Commodity contracts	(2,609)	Purchased gas cost
	(3,667)	Total before tax
	1,403	Tax benefit
Total reclassifications	$(2,264)	Net of tax

	Three Months Ended December 31, 2012	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$(502)	Interest charges
Commodity contracts	(5,160)	Purchased gas cost
	(5,662)	Total before tax
	2,195	Tax benefit

Total reclassifications	$(3,467)	Net of tax

10. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. During the three months ended December 31, 2013, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 6 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2013.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and September 30, 2013. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	December 31, 2013
	(In thousands)				
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$134,812	$—	$—	$134,812
Nonregulated segment	184	103,865	—	(92,434)	11,615
Total financial instruments	184	238,677	—	(92,434)	146,427
Hedged portion of gas stored underground	76,151	—	—	—	76,151
Available-for-sale securities					
Money market funds	—	3,376	—	—	3,376
Registered investment companies	44,000	—	—	—	44,000
Bonds	—	28,014	—	—	28,014
Total available-for-sale securities	44,000	31,390	—	—	75,390
Total assets	$120,335	$270,067	$—	$(92,434)	$297,968
Liabilities:					
Financial instruments					
Natural gas distribution segment	$—	$36	$—	$—	$36
Nonregulated segment	1,172	107,970	—	(109,142)	—
Total liabilities	$1,172	$108,006	$—	$(109,142)	$36

	Quoted Prices in Active Markets (Level 1) (In thousands)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2013
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$111,191	$—	$—	$111,191
Nonregulated segment	745	115,135	—	(105,751)	10,129
Total financial instruments	745	226,326	—	(105,751)	121,320
Hedged portion of gas stored underground	44,758	—	—	—	44,758
Available-for-sale securities					
Money market funds	—	4,428	—	—	4,428
Registered investment companies	40,094	—	—	—	40,094
Bonds	—	28,160	—	—	28,160
Total available-for-sale securities	40,094	32,588	—	—	72,682
Total assets	$85,597	$258,914	$—	$(105,751)	$238,760
Liabilities:					
Financial instruments					
Natural gas distribution segment	$—	$1,543	$—	$—	$1,543
Nonregulated segment	158	130,422	—	(130,580)	—
Total liabilities	$158	$131,965	$—	$(130,580)	$1,543

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

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of December 31, 2013, we had $16.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $7.7 million was used to offset current risk management liabilities under master netting arrangements and the remaining $9.0 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2013 we had $24.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $14.7 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $10.1 million is classified as current risk management assets.

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

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
	(In thousands)			
As of December 31, 2013				
Domestic equity mutual funds	$27,129	$10,575	$—	$37,704
Foreign equity mutual funds	4,536	1,760	—	6,296
Bonds	27,860	176	(22)	28,014
Money market funds	3,376	—	—	3,376
	$62,901	$12,511	$(22)	$75,390
As of September 30, 2013				
Domestic equity mutual funds	$27,043	$7,476	$(23)	$34,496
Foreign equity mutual funds	4,536	1,062	—	5,598
Bonds	28,016	168	(24)	28,160
Money market funds	4,428	—	—	4,428
	$64,023	$8,706	$(47)	$72,682

At December 31, 2013 and September 30, 2013, our available-for-sale securities included $47.4 million and $44.5 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At December 31, 2013, we maintained investments in bonds that have contractual maturity dates ranging from January 2014 through December 2019.

These securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value and the other-than-temporary impairment is recognized in the income statement.

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of December 31, 2013:

	December 31, 2013	September 30, 2013
	(In thousands)	
Carrying Amount	$2,460,000	$2,460,000
Fair Value	$2,661,390	$2,676,487

11. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 15 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. During the three months ended December 31, 2013, there were no material changes in our concentration of credit risk.

12. Discontinued Operations

On April 1, 2013, we completed the sale of substantially all of our natural gas distribution assets and certain related nonregulated assets located in Georgia 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.

For the three months ended December 31, 2012, net income from discontinued operations includes the operating results of our Georgia operations. As required under generally accepted accounting principles, the operating results from our discontinued Georgia operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The table below sets forth statement of income data related to discontinued operations. At December 31, 2013 and September 30, 2013 we did not have any assets or liabilities held for sale.

	Three Months Ended December 31	
	2013	2012
	(In thousands)	
Operating revenues	$—	$16,284
Purchased gas cost	—	8,967
Gross profit	—	7,317
Operating expenses	—	2,820
Operating income	—	4,497
Other nonoperating income	—	348
Income from discontinued operations before income taxes	—	4,845
Income tax expense	—	1,728
Net income from discontinued operations	$—	$3,117

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of December 31, 2013, the related condensed consolidated statements of income and comprehensive income for the three-month periods ended December 31, 2013 and 2012, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2013 and 2012. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with U.S. generally accepted accounting principles.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2013, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 13, 2013, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of September 30, 2013, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 4, 2014

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

INTRODUCTION

The following discussion should be read in conjunction with the condensed consolidated financial statements in this Quarterly Report on Form 10-Q and Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ended September 30, 2013.

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

The statements contained in this Quarterly Report on Form 10-Q 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", "str
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 threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; the risks of accidents and additional operating costs associating with distributing, transporting and storing natural gas; 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.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which at December 31, 2013 covered service areas located in eight states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.

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

As discussed in Note 3, 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.

32

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013 and include the following:

- Regulation
- Unbilled revenue
- Pension and other postretirement plans
- Contingencies
- Financial instruments and hedging activities
- Fair value measurements
- Impairment assessments

Our critical accounting policies are reviewed periodically by the Audit Committee of our Board of Directors. There were no significant changes to these critical accounting policies during the three months ended December 31, 2013.

RESULTS OF OPERATIONS

Atmos Energy strives to operate its businesses safely and reliably while delivering superior shareholder value. To achieve this objective, we are investing in our infrastructure and are seeking to achieve positive rate outcomes that benefit both our customers and the Company.

We experienced a strong financial start to fiscal 2014 with a 12 percent quarter-over-quarter increase in consolidated income from continuing operations. Positive rate outcomes combined with increased throughput across all of our operating segments associated with weather that was 30 percent colder than the prior-year quarter were the key drivers to our financial performance in the fiscal first quarter.

During the first quarter, our capital expenditures were $180 million, which primarily represents investments to improve the safety and reliability of our distribution and transportation systems. We expect our capital expenditures to range between $830 million and $850 million for fiscal 2014, and we plan to fund our growth through the use of operating cash flows, debt and equity securities, while maintaining a balanced capital structure.

Our debt-to-capitalization ratio as of December 31, 2013 was 54.2 percent, which was within our target range of 50 to 55 percent, and our liquidity remained strong with over $1 billion of capacity from our short-term facilities. In October 2014, our $500 million Unsecured 4.95% Senior Notes will mature. We plan to issue new senior unsecured notes to replace this maturing debt. We have executed forward starting interest rate swaps to fix the Treasury yield component associated with this anticipated issuance at 3.129%. On January 30, 2014, Moody's upgraded our senior unsecured debt rating to A2 from Baa1 and our commercial paper rating to P-1 from P-2.

Finally, as a result of the continued contribution and stability of our regulated earnings, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 5.7 percent during the first quarter of fiscal 2014.

Consolidated Results

The following table presents our consolidated financial highlights for the three months ended December 31, 2013 and 2012:

	Three Months Ended December 31	
	2013	2012
	(In thousands, except per share data)	
Operating revenues	$1,255,148	$1,034,155
Gross profit	388,957	362,362
Operating expenses	218,237	207,440
Operating income	170,720	154,922
Miscellaneous income (expense)	(2,132)	698
Interest charges	32,115	30,522
Income from continuing operations before income taxes	136,473	125,098
Income tax expense	49,457	47,750
Income from continuing operations	87,016	77,348
Income from discontinued operations, net of tax	—	3,117
Net income	$87,016	$80,465
Diluted net income per share from continuing operations	$0.95	$0.85
Diluted net income per share from discontinued operations	—	0.03
Diluted net income per share	$0.95	$0.88

Our consolidated net income during the three month periods ended December 31, 2013 and 2012 was earned in each of our business segments as follows:

	Three Months Ended December 31		
	2013	2012	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$62,757	$53,093	$9,664
Regulated transmission and storage segment	19,446	16,105	3,341
Nonregulated segment	4,813	8,150	(3,337)
Net income from continuing operations	87,016	77,348	9,668
Net income from discontinued operations	—	3,117	(3,117)
Net income	$87,016	$80,465	$6,551

Regulated operations contributed 94 percent to our consolidated net income for the three months ended December 31, 2013. The following tables reflect the segregation of our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended December 31		
	2013	2012	Change
	(In thousands, except per share data)		
Regulated operations	$82,203	$69,198	$13,005
Nonregulated operations	4,813	8,150	(3,337)
Net income from continuing operations	87,016	77,348	9,668
Net income from discontinued operations	—	3,117	(3,117)
Net income	$87,016	$80,465	$6,551
Diluted EPS from continuing regulated operations	$0.90	$0.76	$0.14
Diluted EPS from nonregulated operations	0.05	0.09	(0.04)
Diluted EPS from continuing operations	0.95	0.85	0.10
Diluted EPS from discontinued operations	—	0.03	(0.03)
Consolidated diluted EPS	$0.95	$0.88	$0.07

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 of return is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions.

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 97 percent of our residential and commercial meters in the following states for the following time periods:

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

Our natural gas distribution operations are also affected by the cost of natural gas. The cost of gas is passed through to our customers without markup. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas does include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs mean higher bills for our customers, which 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.

Three Months Ended December 31, 2013 compared with Three Months Ended December 31, 2012

Financial and operational highlights for our natural gas distribution segment for the three months ended December 31, 2013 and 2012 are presented below.

	Three Months Ended December 31		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Gross profit	$299,171	$279,631	$19,540
Operating expenses	176,298	170,547	5,751
Operating income	122,873	109,084	13,789
Miscellaneous expense	(471)	(131)	(340)
Interest charges	23,325	23,563	(238)
Income from continuing operations before income taxes	99,077	85,390	13,687
Income tax expense	36,320	32,297	4,023
Income from continuing operations	62,757	53,093	9,664
Income from discontinued operations, net of tax	—	3,117	(3,117)
Net income	$62,757	$56,210	$6,547
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	98,278	78,753	19,525
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	32,207	32,889	(682)
Consolidated natural gas distribution throughput from continuing operations — MMcf	130,485	111,642	18,843
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	2,057	(2,057)
Total consolidated natural gas distribution throughput — MMcf	130,485	113,699	16,786
Consolidated natural gas distribution average transportation revenue per Mcf	$0.48	$0.47	$0.01
Consolidated natural gas distribution average cost of gas per Mcf sold	$5.54	$4.93	$0.61

Income from continuing operations for our natural gas distribution segment increased 18 percent, primarily due to a $19.5 million increase in gross profit, partially offset by a $5.8 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- an $11.0 million increase due to colder weather, primarily experienced in our Mid-Tex Division.
- a $4.9 million increase in revenue related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $4.0 million increase in the related tax expense.
- a $2.1 million net increase in rate adjustments, primarily in our Tennessee and Mississippi service areas.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, primarily due to a $6.0 million increase in employee-related expenses including labor expenses resulting from merit increases and lower labor capitalization rates associated with lower capital expenditures compared with the prior-year quarter and increased employee benefits expenses.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended December 31, 2013 and 2012. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31		
	2013	2012	Change
	(In thousands)		
Mid-Tex	$57,104	$45,577	$11,527
Kentucky/Mid-States	18,097	15,705	2,392
Louisiana	17,426	16,885	541
West Texas	8,042	9,578	(1,536)
Mississippi	12,418	11,613	805
Colorado-Kansas	8,813	8,744	69
Other	973	982	(9)
Total	$122,873	$109,084	$13,789

Recent Ratemaking Developments

The amounts described in the following sections represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling. During the first quarter of fiscal 2014, we completed four regulatory proceedings, resulting in a $16.0 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Infrastructure programs	$3,471
Annual rate filing mechanisms	12,497
Rate case filings	—
Other rate activity	—
	$15,968

Additionally, the following ratemaking efforts seeking $37.3 million in annual operating income were in progress as of December 31, 2013:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Ad Valorem[(1)]	Kansas	$(226)
Colorado-Kansas	GSRS[(2)]	Kansas	882
Colorado/Kansas	Rate Case[(3)]	Colorado	10,891
Kentucky/Mid-States	Rate Case[(4)]	Kentucky	13,133
Louisiana	Rate Stabilization Clause	Trans LA	550
Mississippi	Stable Rate Filing[(5)]	Mississippi	—
West Texas	Rate Case	West Texas	12,032
			$37,262

(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. The commission issued a final order on January 9, 2014 for a decrease in operating income of $0.2 million.

(2)

The Gas System Reliability Surcharge (GSRS) filing relates to a collection of qualified infrastructure in Kansas. The Commission issued an order on January 28, 2014, approving an increase of $0.9 million.

(3) The original requested operating income increase of $10.9 million was to be implemented over three years. On December 20, 2013, we entered into a one-year partial settlement of $2.0 million to be effective January 1, 2014. We

then entered into a unanimous settlement on January 15, 2014 for an operating increase of $1.6 million to be effective March 1, 2014. If the settlement is approved by the Commission, the higher rates will be effective for two months, followed by the smaller increase subsequent to March 1, 2014.

(4) The Kentucky rate case request of $13.1 million includes $2.5 million related to the Kentucky pipeline replacement program (PRP). Effective October 1, 2013, the $2.5 million increase associated with the PRP was included in rates. The ultimate resolution of the rate case will result in all current PRP charges rolling into base rates.

(5) The Commission issued an order approving no change to rates on January 7, 2014.

Infrastructure Programs

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. As of December 31, 2013, we had infrastructure programs approved in Texas, Kansas, Kentucky and Virginia. The following table summarizes our infrastructure program filings with effective dates occurring during the three months ended December 31, 2013.

Division	Period End	Incremental Net Utility Plant Investment (In thousands)	Increase in Annual Operating Income (In thousands)	Effective Date
2014 Infrastructure Programs:				
Kentucky/Mid-States - Kentucky	09/2014	$17,488	$2,493	10/01/2013
Kentucky/Mid-States - Virginia	09/2014	1,587	210	10/01/2013
Mid-Tex - Environs[1]	12/2012	1,473,948	768	10/01/2013
Total 2014 Infrastructure Programs		$1,493,023	$3,471	

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

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. As of December 31, 2013 we had annual rate filing mechanisms in our Louisiana and Mississippi service areas and in a portion of our Texas divisions. These mechanisms are referred to as the Dallas annual rate review (DARR) and rate review mechanism (RRM) in our Mid-Tex Division, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. The following annual rate filing mechanisms were completed during the three months ended December 31, 2013.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
		(In thousands)		
2014 Filings:				
Mid-Tex	Mid-Tex Cities	12/31/2012	$12,497	11/01/2013
Total 2014 Filings			$12,497	

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 arrangements 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.

Three Months Ended December 31, 2013 compared with Three Months Ended December 31, 2012
Financial and operational highlights for our regulated transmission and storage segment for the three months ended December 31, 2013 and 2012 are presented below.

	Three Months Ended December 31		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$49,744	$40,785	$8,959
Third-party transportation	17,159	14,549	2,610
Storage and park and lend services	1,821	1,510	311
Other	2,617	3,837	(1,220)
Gross profit	71,341	60,681	10,660
Operating expenses	31,749	28,659	3,090
Operating income	39,592	32,022	7,570
Miscellaneous expense	(1,181)	(127)	(1,054)
Interest charges	8,957	6,871	2,086
Income before income taxes	29,454	25,024	4,430
Income tax expense	10,008	8,919	1,089
Net income	$19,446	$16,105	$3,341
Gross pipeline transportation volumes — MMcf	189,176	161,484	27,692
Consolidated pipeline transportation volumes — MMcf	118,774	108,743	10,031

Net income for our regulated transmission and storage segment increased 21 percent, primarily due to a $10.7 million increase in gross profit, partially offset by a $3.1 million increase in operating expenses. The increase in gross profit reflects higher rates from the approved 2013 GRIP filing ($6.8 million) coupled with a $1.4 million increase associated with higher throughput driven by colder weather.
Operating expenses increased $3.1 million primarily due to increased depreciation expense associated with increased capital investments and employee-related expenses.

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. On January 1, 2014, the RRC approved the extension of the annual adjustment mechanism retroactive to July 1, 2013, which will stay in place until the completion of APT's next rate case. As a result of this decision, we recognized a $1.8 million increase in gross profit for the application of the annual adjustment mechanism, for the period July 1, 2013 to September 30, 2013.

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.

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.

Three Months Ended December 31, 2013 compared with Three Months Ended December 31, 2012

Financial and operating highlights for our nonregulated segment for the three months ended December 31, 2013 and 2012 are presented below.

	Three Months Ended December 31		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$12,463	$10,070	$2,393
Storage and transportation services	3,535	3,521	14
Other	(8,002)	(14,110)	6,108
Total realized margins	7,996	(519)	8,515
Unrealized margins	10,570	22,978	(12,408)
Gross profit	18,566	22,459	(3,893)
Operating expenses	10,311	8,645	1,666
Operating income	8,255	13,814	(5,559)
Miscellaneous income	324	1,667	(1,343)
Interest charges	637	797	(160)
Income before income taxes	7,942	14,684	(6,742)
Income tax expense	3,129	6,534	(3,405)
Net income	$4,813	$8,150	$(3,337)
Gross nonregulated delivered gas sales volumes — MMcf	107,579	99,009	8,570
Consolidated nonregulated delivered gas sales volumes — MMcf	92,637	84,718	7,919
Net physical position (Bcf)	15.5	25.8	(10.3)

Net income for our nonregulated segment decreased 41 percent from the prior-year quarter due to lower gross profit and increased operating expenses.

The $3.9 million quarter-over-quarter decrease in gross profit reflected an $8.5 million increased in realized margins, offset by a $12.4 million decrease in unrealized margins. The $8.5 million increase in realized margins reflects:

- A $2.4 million increase in gas delivery and related services margins. Consolidated sales volumes increased nine percent as a result of stronger demand from marketing, industrial and utility/municipal customers due to colder weather. Additionally, gas delivery per-unit margins increased from 10 cents per Mcf in the prior-year quarter to 12 cents per Mcf. The increase was a result of increased transportation reimbursements and higher margin incremental sales due to the impact of colder weather.

- A $6.1 million decrease in losses realized on the settlement of financial positions.

Unrealized margins decreased $12.4 million primarily due to the quarter-over-quarter timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses increased $1.7 million, primarily due to increased employee-related and other administrative expenses.

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 capital structure to ensure that we (i) have sufficient liquidity for our short-term and long-term needs in a cost-effective manner and (ii) maintain a balanced capital structure with a debt-to-capitalization ratio in a target range of 50 to 55 percent. We also evaluate the levels of committed borrowing capacity that we require. We currently have over $1 billion of capacity from our short-term facilities. We plan to fund our growth through the use of operating cash flows, debt and equity securities, while maintaining a balanced capital structure.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2013, September 30, 2013 and December 31, 2012:

	December 31, 2013			September 30, 2013			December 31, 2012		
	(In thousands, except percentages)								
Short-term debt[1]	$689,795	11.9	%	$367,984	6.8	%	$830,891	15.9	%
Long-term debt[2]	2,455,750	42.3	%	2,455,671	45.4	%	1,956,507	37.6	%
Shareholders’ equity	2,661,314	45.8	%	2,580,409	47.8	%	2,424,005	46.5	%
Total	$5,806,859	100.0	%	$5,404,064	100.0	%	$5,211,403	100.0	%

(1) Short-term debt at December 31, 2012 included $260 million outstanding related to a short-term facility we used to redeem our $250 million 5.125% Senior notes in August 2012. The balance outstanding under this short-term facility was repaid in January 2013.

(2) In October 2014, $500 million of long-term debt will mature. We plan to issue new senior notes to replace this maturing debt. We have executed forward starting interest rate swaps to fix the Treasury yield component associated with this anticipated issuance at 3.129%.

Total debt as a percentage of total capitalization, including short-term debt, was 54.2 percent at December 31, 2013, 52.2 percent at September 30, 2013 and 53.5 percent at December 31, 2012.

Cash Flows

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

Cash flows from operating, investing and financing activities for the three months ended December 31, 2013 and 2012 are presented below.

	Three Months Ended December 31				
	2013		2012		Change
	(In thousands)				
Total cash provided by (used in)					
Operating activities	$34,300		$29,858		$4,442
Investing activities	(186,434	)	(191,300	)	4,866
Financing activities	280,498		221,804		58,694
Change in cash and cash equivalents	128,364		60,362		68,002
Cash and cash equivalents at beginning of period	66,199		64,239		1,960
Cash and cash equivalents at end of period	$194,563		$124,601		$69,962

Cash flows from operating activities

Period-over-period changes in our operating cash flows are primarily attributable to changes in net income and 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 deferred gas cost recoveries.

For the three months ended December 31, 2013, we generated cash flow of $34.3 million from operating activities compared with $29.9 million for the three months ended December 31, 2012. The $4.4 million increase in operating cash flows primarily reflects the timing of customer collections and vendor payments, including higher gas purchases.

Cash flows from investing activities

In recent years, a substantial portion of our cash resources has been used to fund growth projects in our regulated operations, our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to enhance the safety and reliability of the systems used to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our regulatory strategy, we 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. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution divisions and our Atmos Pipeline–Texas Division have rate tariffs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

For the three months ended December 31, 2013, capital expenditures were $180.6 million, compared with $190.0 million in the prior-year period. The period-over-period decrease primarily reflects:

- An $18.4 million decrease in capital spending in our natural gas distribution segment due to the timing of spending under our infrastructure replacement programs, partially due to adverse weather conditions and the absence of spending related to our new customer information system which was completed in the prior year.
- A $9.1 million increase in capital spending in our regulated transmission and storage segment associated with the completion of the Line WX expansion project and increased cathodic protection spending.

Cash flows from financing activities

For the three months ended December 31, 2013, our financing activities generated $280.5 million of cash compared with $221.8 million in the prior-year period. The increase is primarily due to timing between short-term debt borrowings and repayments during the current quarter.

The following table summarizes our share issuances for the three months ended December 31, 2013 and 2012.

	Three Months Ended December 31	
	2013	2012
Shares issued:		
1998 Long-Term Incentive Plan	450,943	364,415
Outside Directors Stock-for-Fee Plan	473	564
Total shares issued	451,416	364,979

The year-over-year increase in the number of shares issued primarily reflects a higher number of performance-based awards issued in the current year as actual performance exceeded the target. For the three months ended December 31, 2013 and 2012, we canceled and retired 133,325 and 87,931 shares attributable to federal withholdings on equity awards.

Credit Facilities

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

We finance our short-term borrowing requirements through a combination of a $950.0 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.0 billion of working capital funding. As of December 31, 2013, the amount available to us under our credit facilities, net of outstanding letters of credit, was $304.7 million.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.75 billion in common stock and/or debt securities. At December 31, 2013, no securities had been issued 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 structures that govern our rates in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor’s Corporation (S&P), Moody’s Investors Service (Moody’s) and Fitch Ratings, Ltd. (Fitch). As of December 31, 2013, all three ratings agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

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

On January 30, 2014, Moody's upgraded our senior unsecured debt rating to A2 from Baa1 and our commercial paper rating to P-1 from P-2.

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2013. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments

Significant commercial commitments are described in Note 7 to the unaudited condensed consolidated financial statements. There were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2013.

Risk Management Activities

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

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the three months ended December 31, 2013 and 2012:

	Three Months Ended December 31	
	2013	2012
	(In thousands)	
Fair value of contracts at beginning of period	$109,648	$(76,260)
Contracts realized/settled	(1,671)	2,834
Fair value of new contracts	519	331
Other changes in value	26,280	8,898
Fair value of contracts at end of period	$134,776	$(64,197)

The fair value of our natural gas distribution segment's financial instruments at December 31, 2013 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2013 Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$88,898	$45,878	$—	$—	$134,776
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$88,898	$45,878	$—	$—	$134,776

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three months ended December 31, 2013 and 2012:

	Three Months Ended December 31	
	2013	2012
	(In thousands)	
Fair value of contracts at beginning of period	$(14,700)	$(15,123)
Contracts realized/settled	9,943	12,736
Fair value of new contracts	—	—
Other changes in value	(336)	825
Fair value of contracts at end of period	(5,093)	(1,562)
Netting of cash collateral	16,708	16,559
Cash collateral and fair value of contracts at period end	$11,615	$14,997

The fair value of our nonregulated segment's financial instruments at December 31, 2013 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2013 Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(7,707)	$2,864	$(250)	$—	$(5,093)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(7,707)	$2,864	$(250)	$—	$(5,093)

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2013 and 2012, our total net periodic pension and other benefits costs were $20.9 million and $18.9 million. A substantial portion of those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2014 costs were determined using a September 30, 2013 measurement date. As of September 30, 2013, interest and corporate bond rates utilized to determine our discount rates were higher than the interest and corporate bond rates as of September 30, 2012, the measurement date for our fiscal 2013 net periodic cost. Therefore, we increased the discount rate used to measure our fiscal 2014 net periodic cost from 4.04 percent to 4.95 percent. However, we decreased the expected return on plan assets from 7.75 percent to 7.25 percent in the determination of our fiscal 2014 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2014 net periodic pension cost to decrease by less than five percent.

The amounts with which we fund our defined benefit plans are determined in accordance with the Pension Protection Act of 2006 (PPA) and are influenced by the funded position of the plans when the funding requirements are determined on January 1 of each year. For the three months ended December 31, 2013 we contributed $4.7 million to our defined benefit plans. Based upon the most recent evaluation, we anticipate contributing a total of between $15 million and $20 million to our defined benefit plans in fiscal 2014. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. For the three months ended December 31, 2013 we contributed $5.9 million to our postretirement medical plans. We anticipate contributing a total of between $20 million and $25 million to these plans during fiscal 2014.

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

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our natural gas distribution, regulated transmission and storage and nonregulated segments for the three month periods ended December 31, 2013 and 2012.

Natural Gas Distribution Sales and Statistical Data — Continuing Operations

	Three Months Ended December 31	
	2013	2012
METERS IN SERVICE, end of period		
Residential	2,782,064	2,805,013
Commercial	249,348	256,030
Industrial	1,508	2,127
Public authority and other	10,011	10,169
Total meters	3,042,931	3,073,339
INVENTORY STORAGE BALANCE — Bcf[1]	52.5	54.8
SALES VOLUMES — MMcf[2]		
Gas sales volumes		
Residential	60,416	46,323
Commercial	31,414	25,256
Industrial	4,019	4,555
Public authority and other	2,429	2,619
Total gas sales volumes	98,278	78,753
Transportation volumes	35,424	34,022
Total throughput	133,702	112,775
OPERATING REVENUES (000's)[2]		
Gas sales revenues		
Residential	$545,417	$422,721
Commercial	235,423	184,931
Industrial	23,748	21,456
Public authority and other	16,449	15,680
Total gas sales revenues	821,037	644,788
Transportation revenues	16,817	15,441
Other gas revenues	6,011	6,558
Total operating revenues	$843,865	$666,787
Average transportation revenue per Mcf[1]	$0.47	$0.46
Average cost of gas per Mcf sold[1]	$5.54	$4.93

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data — Discontinued Operations

	Three Months Ended December 31	
	2013	2012
Meters in service, end of period	—	63,959
Sales volumes — MMcf		
Total gas sales volumes	—	1,542
Transportation volumes	—	515
Total throughput	—	2,057
Operating revenues (000’s)	$—	$16,284

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended December 31	
	2013	2012
CUSTOMERS, end of period		
Industrial	758	732
Municipal	126	128
Other	546	423
Total	1,430	1,283
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	21.1	26.9
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf[2]	189,176	161,484
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[2]	107,579	99,009
OPERATING REVENUES (000’s)[2]		
Regulated transmission and storage	$71,341	$60,681
Nonregulated	447,721	399,894
Total operating revenues	$519,062	$460,575

Notes to preceding tables:

(1) Statistics are shown on a consolidated basis.

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

RECENT ACCOUNTING DEVELOPMENTS

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information regarding our quantitative and qualitative disclosures about market risk are disclosed in Item 7A in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. During the three months ended December 31, 2013, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. Controls and Procedures

Management’s Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company’s disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company’s principal executive officer and principal financial officer have concluded that the Company’s disclosure controls and procedures were effective as of December 31, 2013 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC’s rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

During the three months ended December 31, 2013, except as noted in Note 7 to the unaudited condensed consolidated financial statements, there were no material changes in the status of the litigation and other matters that were disclosed in Note 10 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2013. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. Exhibits

A list of exhibits required by Item 601 of Regulation S-K and filed as part of this report is set forth in the Exhibits Index, which immediately precedes such exhibits.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)
By: /s/ BRET J. ECKERT
Bret J. Eckert
Senior Vice President and Chief Financial Officer
(Duly authorized signatory)

Date: February 4, 2014

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

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