UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015

or

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

For the transition period from to

Commission File Number 1-10042

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

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

(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 ☑ 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 ☑ 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 ☑ 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 ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of July 31, 2015.

Class	Shares Outstanding
No Par Value	101,369,699

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
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

	June 30, 2015	September 30, 2014
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 9,017,043	$ 8,447,700
Less accumulated depreciation and amortization	1,804,955	1,721,794
Net property, plant and equipment	7,212,088	6,725,906
Current assets		
Cash and cash equivalents	43,153	42,258
Accounts receivable, net	301,743	343,400
Gas stored underground	213,151	278,917
Other current assets	58,602	111,265
Total current assets	616,649	775,840
Goodwill	742,029	742,029
Deferred charges and other assets	313,723	350,929
	$ 8,884,489	$ 8,594,704
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: June 30, 2015 — 101,336,818 shares; September 30, 2014 — 100,388,092 shares	$ 507	$ 502
Additional paid-in capital	2,207,102	2,180,151
Retained earnings	1,092,887	917,972
Accumulated other comprehensive loss	(62,241)	(12,393)
Shareholders' equity	3,238,255	3,086,232
Long-term debt	2,455,303	2,455,986
Total capitalization	5,693,558	5,542,218
Current liabilities		
Accounts payable and accrued liabilities	227,256	308,086
Other current liabilities	437,344	405,869
Short-term debt	251,977	196,695
Total current liabilities	916,577	910,650
Deferred income taxes	1,429,090	1,286,616
Regulatory cost of removal obligation	432,153	445,387
Pension and postretirement liabilities	318,140	340,963
Deferred credits and other liabilities	94,971	68,870
	$ 8,884,489	$ 8,594,704

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2015	2014
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 416,794	$ 517,707
Regulated pipeline segment	97,008	87,189
Nonregulated segment	278,769	465,485
Intersegment eliminations	(106,170)	(127,211)
	686,401	943,170
Purchased gas cost		
Regulated distribution segment	149,775	260,042
Regulated pipeline segment	—	—
Nonregulated segment	260,990	450,672
Intersegment eliminations	(106,037)	(127,077)
	304,728	583,637
Gross profit	381,673	359,533
Operating expenses		
Operation and maintenance	132,447	125,559
Depreciation and amortization	68,444	63,955
Taxes, other than income	63,175	63,414
Total operating expenses	264,066	252,928
Operating income	117,607	106,605
Miscellaneous income (expense)	634	(374)
Interest charges	27,955	31,840
Income before income taxes	90,286	74,391
Income tax expense	34,005	28,670
Net income	$ 56,281	$ 45,721
Basic net income per share	$ 0.55	$ 0.45
Diluted net income per share	$ 0.55	$ 0.45
Cash dividends per share	$ 0.39	$ 0.37
Weighted average shares outstanding:		
Basic	102,000	101,162
Diluted	102,000	101,163

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2015	2014
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 2,394,179	$ 2,652,532
Regulated pipeline segment	272,305	232,145
Nonregulated segment	1,179,379	1,660,131
Intersegment eliminations	(360,629)	(392,926)
	3,485,234	4,151,882
Purchased gas cost		
Regulated distribution segment	1,397,113	1,710,508
Regulated pipeline segment	—	—
Nonregulated segment	1,122,655	1,589,163
Intersegment eliminations	(360,230)	(392,556)
	2,159,538	2,907,115
Gross profit	1,325,696	1,244,767
Operating expenses		
Operation and maintenance	384,489	365,991
Depreciation and amortization	204,059	185,731
Taxes, other than income	181,606	165,640
Total operating expenses	770,154	717,362
Operating income	555,542	527,405
Miscellaneous expense	(2,634)	(4,022)
Interest charges	85,166	95,556
Income before income taxes	467,742	427,827
Income tax expense	176,182	161,723
Net income	291,560	266,104
Basic net income per share	$ 2.86	$ 2.76
Diluted net income per share	$ 2.86	$ 2.76
Cash dividends per share	$ 1.17	$ 1.11
Weighted average shares outstanding:		
Basic	101,776	96,392
Diluted	101,776	96,394

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
	(Unaudited) (In thousands)			
Net income	$ 56,281	$ 45,721	$ 291,560	$ 266,104
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(41), $216, $(170) and $1,518	(191)	377	(296)	2,519
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $31,314, $(13,472), $(17,232) and $(21,005)	54,475	(23,440)	(29,981)	(36,545)
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $7,393, $(1,580), $(12,698) and $4,122	11,563	(2,471)	(19,571)	6,448
Total other comprehensive income (loss)	65,847	(25,534)	(49,848)	(27,578)
Total comprehensive income	$ 122,128	$ 20,187	$ 241,712	$ 238,526

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2015	2014
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 291,560	$ 266,104
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	204,059	185,731
Charged to other accounts	853	669
Deferred income taxes	164,627	150,457
Other	18,146	21,587
Net assets / liabilities from risk management activities	(13,136)	3,158
Net change in operating assets and liabilities	51,473	2,504
Net cash provided by operating activities	717,582	630,210
Cash Flows From Investing Activities		
Capital expenditures	(667,483)	(552,600)
Other, net	(1,119)	(620)
Net cash used in investing activities	(668,602)	(553,220)
Cash Flows From Financing Activities		
Net increase (decrease) in short-term debt	48,830	(366,602)
Net proceeds from equity offering	—	390,205
Net proceeds from issuance of long-term debt	493,538	—
Settlement of interest rate agreements	13,364	—
Repayment of long-term debt	(500,000)	—
Cash dividends paid	(116,645)	(108,806)
Repurchase of equity awards	(7,985)	(8,717)
Issuance of common stock	20,813	2,152
Net cash used in financing activities	(48,085)	(91,768)
Net increase (decrease) in cash and cash equivalents	895	(14,778)
Cash and cash equivalents at beginning of period	42,258	66,199
Cash and cash equivalents at end of period	$ 43,153	$ 51,421

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2015

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 pipeline businesses as well as other nonregulated natural gas businesses. Historically, our regulated businesses have generated over 90 percent of our consolidated net income.

Through our regulated 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 distribution divisions, which at June 30, 2015, covered service areas located in eight states. 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 North Texas 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 regulated 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.

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, 2014. 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, 2014. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2015 are not indicative of our results of operations for the full 2015 fiscal year, which ends September 30, 2015.

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, 2014.

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

During the second quarter of fiscal 2015, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

In May 2014, the Financial Accounting Standards Board (FASB) issued a comprehensive new revenue recognition standard that will supersede virtually all existing revenue recognition guidance under generally accepted accounting principles in the United States. Under the new standard, a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under current guidance. On July 9, 2015, the FASB voted to approve a deferral of the effective date of the new standard by one year. With the one year extension, the new standard is currently scheduled to become effective for us beginning on October 1, 2018 and can be applied either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In April 2015, the FASB issued guidance to simplify the presentation of debt issuance costs which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The new standard will be effective for us beginning on October 1, 2016, and will be applied retrospectively. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In April 2015, the FASB issued guidance to simplify the accounting for fees paid in connection with arrangements with cloud-based software providers. Under the new guidance, unless a software arrangement includes specific elements enabling customers to possess and operate software on platforms other than that offered by the cloud-based provider, the cost of such arrangements is to be accounted for as an operating expense in the period incurred. The new guidance is effective for us beginning October 1, 2016 and may be applied either prospectively or retrospectively with early adoption permitted. We anticipate the adoption of this standard will not have a material impact on our financial position, results of operations and cash flows.

There were no other significant changes to our accounting policies during the nine months ended June 30, 2015 that will become applicable to the Company in future periods.

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 June 30, 2015 and September 30, 2014 included the following:

	June 30, 2015	September 30, 2014
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$ 149,202	$ 162,777
Merger and integration costs, net	4,327	4,730
Deferred gas costs	1,494	20,069
Rate case costs	1,354	3,757
Infrastructure Mechanisms[2]	24,228	26,948
APT annual adjustment mechanism	—	8,479
Recoverable loss on reacquired debt	16,959	18,877
Other	4,944	4,672
	$ 202,508	$ 250,309
Regulatory liabilities:		
Deferred gas costs	$ 81,134	$ 35,063
Deferred franchise fees	747	5,268
Regulatory cost of removal obligation	486,672	490,448
Other	12,810	14,980
	$ 581,363	$ 545,759

(1) Includes $15.8 million and $18.8 million of pension and postretirement expense deferred pursuant to regulatory authorization.

(2) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, including the recording of interest expense, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable 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

We operate the Company through the following three segments:

- The *regulated distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated pipeline 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 regulated distribution segment operations are geographically dispersed, they are reported as a single segment as each regulated 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, 2014. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and nine month periods ended June 30, 2015 and 2014 by segment are presented in the following tables:

	Three Months Ended June 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 415,160	$ 25,859	$ 245,382	$ —	$ 686,401
Intersegment revenues	1,634	71,149	33,387	(106,170)	—
	416,794	97,008	278,769	(106,170)	686,401
Purchased gas cost	149,775	—	260,990	(106,037)	304,728
Gross profit	267,019	97,008	17,779	(133)	381,673
Operating expenses					
Operation and maintenance	98,552	26,572	7,456	(133)	132,447
Depreciation and amortization	55,491	11,816	1,137	—	68,444
Taxes, other than income	56,176	6,193	806	—	63,175
Total operating expenses	210,219	44,581	9,399	(133)	264,066
Operating income	56,800	52,427	8,380	—	117,607
Miscellaneous income (expense)	1,045	(211)	345	(545)	634
Interest charges	19,961	8,299	240	(545)	27,955
Income before income taxes	37,884	43,917	8,485	—	90,286
Income tax expense	15,420	15,349	3,236	—	34,005
Net income	$ 22,464	$ 28,568	$ 5,249	$ —	$ 56,281
Capital expenditures	$ 170,134	$ 55,914	$ (209)	$ —	$ 225,839

	Three Months Ended June 30, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 516,644	$ 24,990	$ 401,536	$ —	$ 943,170
Intersegment revenues	1,063	62,199	63,949	(127,211)	—
	517,707	87,189	465,485	(127,211)	943,170
Purchased gas cost	260,042	—	450,672	(127,077)	583,637
Gross profit	257,665	87,189	14,813	(134)	359,533
Operating expenses					
Operation and maintenance	92,994	23,570	9,129	(134)	125,559
Depreciation and amortization	52,542	10,281	1,132	—	63,955
Taxes, other than income	57,596	5,054	764	—	63,414
Total operating expenses	203,132	38,905	11,025	(134)	252,928
Operating income	54,533	48,284	3,788	—	106,605
Miscellaneous income (expense)	678	(489)	1,018	(1,581)	(374)
Interest charges	23,649	9,162	610	(1,581)	31,840
Income before income taxes	31,562	38,633	4,196	—	74,391
Income tax expense	13,033	13,695	1,942	—	28,670
Net income	$ 18,529	$ 24,938	$ 2,254	$ —	$ 45,721
Capital expenditures	$ 146,860	$ 45,658	$ 1,073	$ —	$ 193,591

	Nine Months Ended June 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,389,037	$ 70,887	$ 1,025,310	$ —	$ 3,485,234
Intersegment revenues	5,142	201,418	154,069	(360,629)	—
	2,394,179	272,305	1,179,379	(360,629)	3,485,234
Purchased gas cost	1,397,113	—	1,122,655	(360,230)	2,159,538
Gross profit	997,066	272,305	56,724	(399)	1,325,696
Operating expenses					
Operation and maintenance	288,962	74,029	21,897	(399)	384,489
Depreciation and amortization	165,730	34,945	3,384	—	204,059
Taxes, other than income	162,759	16,296	2,551	—	181,606
Total operating expenses	617,451	125,270	27,832	(399)	770,154
Operating income	379,615	147,035	28,892	—	555,542
Miscellaneous income (expense)	(1,221)	(842)	897	(1,468)	(2,634)
Interest charges	60,914	25,014	706	(1,468)	85,166
Income before income taxes	317,480	121,179	29,083	—	467,742
Income tax expense	121,776	42,894	11,512	—	176,182
Net income	$ 195,704	$ 78,285	$ 17,571	$ —	$ 291,560
Capital expenditures	$ 482,371	$ 185,028	$ 84	$ —	$ 667,483

	Nine Months Ended June 30, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,648,505	$ 67,162	$ 1,436,215	$ —	$ 4,151,882
Intersegment revenues	4,027	164,983	223,916	(392,926)	—
	2,652,532	232,145	1,660,131	(392,926)	4,151,882
Purchased gas cost	1,710,508	—	1,589,163	(392,556)	2,907,115
Gross profit	942,024	232,145	70,968	(370)	1,244,767
Operating expenses					
Operation and maintenance	289,433	57,465	19,463	(370)	365,991
Depreciation and amortization	152,113	30,223	3,395	—	185,731
Taxes, other than income	155,286	8,485	1,869	—	165,640
Total operating expenses	596,832	96,173	24,727	(370)	717,362
Operating income	345,192	135,972	46,241	—	527,405
Miscellaneous income (expense)	304	(2,751)	1,785	(3,360)	(4,022)
Interest charges	69,802	27,274	1,840	(3,360)	95,556
Income before income taxes	275,694	105,947	46,186	—	427,827
Income tax expense	105,665	37,454	18,604	—	161,723
Net income	$ 170,029	$ 68,493	$ 27,582	$ —	$ 266,104
Capital expenditures	$ 413,921	$ 137,579	$ 1,100	$ —	$ 552,600

Balance sheet information at June 30, 2015 and September 30, 2014 by segment is presented in the following tables:

	June 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,543,386	$ 1,613,182	$ 55,520	$ —	$ 7,212,088
Investment in subsidiaries	1,028,457	—	(2,096)	(1,026,361)	—
Current assets					
Cash and cash equivalents	35,288	—	7,865	—	43,153
Assets from risk management activities	780	—	10,806	—	11,586
Other current assets	375,213	20,100	497,871	(331,274)	561,910
Intercompany receivables	820,587	—	—	(820,587)	—
Total current assets	1,231,868	20,100	516,542	(1,151,861)	616,649
Goodwill	574,816	132,502	34,711	—	742,029
Noncurrent assets from risk management activities	1,109	—	—	—	1,109
Deferred charges and other assets	291,740	15,305	5,569	—	312,614
	$ 8,671,376	$ 1,781,089	$ 610,246	$ (2,178,222)	$ 8,884,489
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,238,255	$ 560,898	$ 467,559	$ (1,028,457)	$ 3,238,255
Long-term debt	2,455,303	—	—	—	2,455,303
Total capitalization	5,693,558	560,898	467,559	(1,028,457)	5,693,558
Current liabilities					
Short-term debt	570,977	—	—	(319,000)	251,977
Liabilities from risk management activities	4,916	—	—	—	4,916
Other current liabilities	551,102	17,850	100,910	(10,178)	659,684
Intercompany payables	—	786,493	34,094	(820,587)	—
Total current liabilities	1,126,995	804,343	135,004	(1,149,765)	916,577
Deferred income taxes	1,014,432	415,687	(1,029)	—	1,429,090
Noncurrent liabilities from risk management activities	47,224	—	—	—	47,224
Regulatory cost of removal obligation	432,153	—	—	—	432,153
Pension and postretirement liabilities	318,140	—	—	—	318,140
Deferred credits and other liabilities	38,874	161	8,712	—	47,747
	$ 8,671,376	$ 1,781,089	$ 610,246	$ (2,178,222)	$ 8,884,489

	September 30, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,202,761	$ 1,464,572	$ 58,573	$ —	$ 6,725,906
Investment in subsidiaries	952,171	—	(2,096)	(950,075)	—
Current assets					
Cash and cash equivalents	33,303	—	8,955	—	42,258
Assets from risk management activities	23,102	—	22,725	—	45,827
Other current assets	490,408	14,009	526,161	(342,823)	687,755
Intercompany receivables	790,442	—	—	(790,442)	—
Total current assets	1,337,255	14,009	557,841	(1,133,265)	775,840
Goodwill	574,816	132,502	34,711	—	742,029
Noncurrent assets from risk management activities	13,038	—	—	—	13,038
Deferred charges and other assets	309,965	21,826	6,100	—	337,891
	$ 8,390,006	$ 1,632,909	$ 655,129	$ (2,083,340)	$ 8,594,704
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,086,232	$ 482,612	$ 469,559	$ (952,171)	$ 3,086,232
Long-term debt	2,455,986	—	—	—	2,455,986
Total capitalization	5,542,218	482,612	469,559	(952,171)	5,542,218
Current liabilities					
Short-term debt	522,695	—	—	(326,000)	196,695
Liabilities from risk management activities	1,730	—	—	—	1,730
Other current liabilities	559,765	24,790	142,397	(14,727)	712,225
Intercompany payables	—	763,635	26,807	(790,442)	—
Total current liabilities	1,084,190	788,425	169,204	(1,131,169)	910,650
Deferred income taxes	913,260	361,688	11,668	—	1,286,616
Noncurrent liabilities from risk management activities	20,126	—	—	—	20,126
Regulatory cost of removal obligation	445,387	—	—	—	445,387
Pension and postretirement liabilities	340,963	—	—	—	340,963
Deferred credits and other liabilities	43,862	184	4,698	—	48,744
	$ 8,390,006	$ 1,632,909	$ 655,129	$ (2,083,340)	$ 8,594,704

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 and nine months ended June 30, 2015 and 2014 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
	(In thousands, except per share amounts)			
Basic Earnings Per Share				
Net income	$ 56,281	$ 45,721	$ 291,560	$ 266,104
Less: Income allocated to participating securities	111	106	596	667
Income available to common shareholders	$ 56,170	$ 45,615	$ 290,964	$ 265,437
Basic weighted average shares outstanding	102,000	101,162	101,776	96,392
Net income per share - Basic	$ 0.55	$ 0.45	$ 2.86	$ 2.76
Diluted Earnings Per Share				
Net income available to common shareholders	$ 56,170	$ 45,615	290,964	265,437
Effect of dilutive stock options and other shares	—	—	—	—
Net income available to common shareholders	$ 56,170	$ 45,615	290,964	265,437
Basic weighted average shares outstanding	102,000	101,162	101,776	96,392
Additional dilutive stock options and other shares	—	1	—	2
Diluted weighted average shares outstanding	102,000	101,163	101,776	96,394
Net income per share - Diluted	$ 0.55	$ 0.45	$ 2.86	$ 2.76

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2014 as their exercise price was less than the average market price of the common stock during those periods. As of June 30, 2015 there were no outstanding options.

2014 Equity Offering

On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock, including the underwriters' exercise of their overallotment option of 1,200,000 shares under our existing shelf registration statement. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our commercial paper program, fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

2011 Share Repurchase Program

We did not repurchase any shares during the nine months ended June 30, 2015 and 2014 under our 2011 share repurchase program, which is scheduled to end on September 30, 2016.

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, 2014. Except as noted below, there were no material changes in the terms of our debt instruments during the nine months ended June 30, 2015.

Long-term debt

Long-term debt at June 30, 2015 and September 30, 2014 consisted of the following:

	June 30, 2015	September 30, 2014
	(In thousands)	
Unsecured 4.95% Senior Notes, due October 2014	$ —	$ 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
Unsecured 4.125% Senior Notes, due 2044	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	4,697	4,014
	$ 2,455,303	$ 2,455,986

On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million unsecured 4.95% senior notes. The effective rate of these notes is 4.086%, after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps. The net proceeds of approximately $494 million were used to repay our $500 million 4.95% senior unsecured notes at maturity on October 15, 2014.

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 $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1.3 billion of working capital funding. At June 30, 2015 and September 30, 2014 a total of $252.0 million and $196.7 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 $1.3 billion of working capital funding, including a five-year $1.25 billion unsecured facility with an accordion feature, which, if utilized would increase the borrowing capacity to $1.5 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 $4.2 million at June 30, 2015.

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 lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2015.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, has one uncommitted $25 million 364-day bilateral credit facility and one committed $15 million 364-day bilateral credit facility that expire in December 2015. 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 $36.0 million at June 30, 2015.

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. Applicable state regulatory commissions have approved our use of this facility through December 31, 2015.

Shelf Registration

We filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013 that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. At June 30, 2015, $845 million of securities remain available for issuance under the shelf registration statement until March 28, 2016.

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 June 30, 2015, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 47 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 June 30, 2015. 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 and nine months ended June 30, 2015 and 2014 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 executive officers, we recognized a settlement loss of $4.5 million associated with our Supplemental Executive Benefits Plan (SEBP). In association with his retirement, on October 2, 2013, we made a $16.8 million benefit payment from the SEBP.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 5,051	$ 4,738	$ 3,895	$ 4,196
Interest cost	6,698	6,824	3,596	3,987
Expected return on assets	(6,435)	(5,901)	(1,608)	(1,291)
Amortization of transition obligation	—	—	69	69
Amortization of prior service credit	(48)	(34)	(411)	(363)
Amortization of actuarial loss	3,916	3,931	—	158
Net periodic pension cost	$ 9,182	$ 9,558	$ 5,541	$ 6,756

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 15,153	$ 14,214	$ 11,687	$ 12,588
Interest cost	20,095	20,472	10,789	11,963
Expected return on assets	(19,308)	(17,702)	(4,824)	(3,875)
Amortization of transition obligation	—	—	205	205
Amortization of prior service credit	(144)	(102)	(1,233)	(1,088)
Amortization of actuarial loss	11,749	11,793	—	474
Settlement loss	—	4,539	—	—
Net periodic pension cost	$ 27,545	$ 33,214	$ 16,624	$ 20,267

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2015 and 2014 are as follows:

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Discount rate	4.43%	4.95%	4.43%	4.95%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.25%	7.25%	4.60%	4.60%

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, 2015. Based on that determination, we are not required to make a minimum contribution to our defined benefit plans during fiscal 2015. However, we made a voluntary contribution of $38.0 million during the third quarter of fiscal 2015.

We contributed $15.0 million to our other post-retirement benefit plans during the nine months ended June 30, 2015. We expect to contribute a total of approximately $20 million to these plans during all of fiscal 2015.

In October 2014, the Society of Actuaries released its final report on mortality tables and the mortality improvement scale to reflect increasing life expectancies in the United States. We anticipate utilizing the new mortality data in our next actuarial calculation date on September 30, 2015. We are currently evaluating the impact the updated data will have on the valuation of our defined benefit and other post-retirement benefits plans. It is expected the use of this new data will increase the total amount of liabilities reported on our balance sheet in future periods by less than five percent.

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, 2014, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2015.

We are a party to various 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

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

Our Mid-Tex Division also maintains a limited number of long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at prices indexed to natural gas distribution hubs. At June 30, 2015, we were committed to purchase 36.6 Bcf within one year and 35.2 Bcf within two years under indexed contracts. Purchases under these contracts totaled $21.2 million and $27.8 million for the three months ended June 30, 2015 and 2014 and $93.2 million, and $81.9 million for the nine months ended June 30, 2015 and 2014.

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2015, AEH was committed to purchase 99.1 Bcf within one year, 22.6 Bcf within one to three years and 0.2 Bcf after three years under indexed contracts. AEH is committed to purchase 4.1 Bcf within one year under fixed price contracts with prices ranging from $2.62 to $3.23 per Mcf. Purchases under these contracts totaled $203.3 million and $383.2 million for the three months ended June 30, 2015 and 2014 and $925.4 million and $1,354.5 million for the nine months ended June 30, 2015 and 2014.

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, 2014. There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2015.

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 June 30, 2015, a rate case was in progress in our Colorado service area, an annual rate filing mechanism was in progress in Louisiana and an infrastructure program was in progress in Virginia. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

8. Financial Instruments

We currently use financial instruments in our regulated distribution and nonregulated segments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments, which have been tailored to our regulated distribution and nonregulated segments, and the related accounting for these financial instruments are fully described in Notes 2 and 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2014. During the nine months ended June 30, 2015 there were no changes in our objectives, strategies and accounting for using financial instruments. 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. The following summarizes those objectives and strategies.

Regulated Commodity Risk Management Activities

Our purchased gas cost adjustment mechanisms essentially insulate our regulated distribution segment from commodity price risk; however, 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.

We typically seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2014-2015 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 37 percent, or 28.2 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Nonregulated Commodity Risk Management Activities

Our nonregulated segment is exposed to risks associated with changes in the market price of natural gas through the purchase, sale and delivery of natural gas to its customers at competitive prices. 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. Specifically, these operations use financial instruments in the following ways:

- *Gas delivery and related services* - Certain financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, are used to mitigate the commodity price risk associated with deliveries under fixed-priced forward contracts to either deliver gas to customers or purchase gas from suppliers. These financial instruments have maturity dates ranging from one to 52 months.
- *Transportation and storage services* - Our nonregulated operations 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.
- *Aggregating and purchasing gas supply* - Certain financial instruments, designated as fair value hedges, are used to hedge our natural gas inventory used in asset optimization activities.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

As of June 30, 2015, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $250 million and $450 million unsecured senior notes in fiscal 2017 and fiscal 2019, at 3.37% and 3.78%, which we designated as cash flow hedges at the time the swaps were executed. As of June 30, 2015, we had $18.7 million of net realized losses in accumulated other comprehensive income (AOCI) associated with the settlement of financial instruments used to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes, which will be recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these settled amounts extend through fiscal 2045.

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 June 30, 2015, 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 June 30, 2015, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Regulated Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(25,020)
	Cash Flow	—	55,158
	Not designated	14,609	65,577
		14,609	95,715

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 June 30, 2015 and September 30, 2014. 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.

		Regulated Distribution		Nonregulated	
	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
			(In thousands)		
June 30, 2015					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 8,465	$ (31,422)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	476	(7,591)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	570	(47,224)	—	—
Total		570	(47,224)	8,941	(39,013)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	780	(4,916)	86,265	(78,374)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	539	—	9,000	(7,336)
Total		1,319	(4,916)	95,265	(85,710)
Gross Financial Instruments		1,889	(52,140)	104,206	(124,723)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(104,206)	104,206
Net Financial Instruments		1,889	(52,140)	—	(20,517)
Cash collateral		—	—	10,806	20,517
Net Assets/Liabilities from Risk Management Activities		$ 1,889	$ (52,140)	$ 10,806	$ —

	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
			(In thousands)		
September 30, 2014					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 8,912	$ (7,082)
Interest rate contracts	Other current assets / Other current liabilities	21,869	—	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	757	(2,459)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	12,608	(19,835)	—	—
Total		34,477	(19,835)	9,669	(9,541)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	1,233	(1,730)	43,677	(47,729)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	430	(291)	15,677	(14,786)
Total		1,663	(2,021)	59,354	(62,515)
Gross Financial Instruments		36,140	(21,856)	69,023	(72,056)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(69,023)	69,023
Net Financial Instruments		36,140	(21,856)	—	(3,033)
Cash collateral		—	—	22,725	3,033
Net Assets/Liabilities from Risk Management Activities		$ 36,140	$ (21,856)	$ 22,725	$ —

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of purchased gas cost 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 June 30, 2015 and 2014 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $3.6 million and $(0.1) million. For the nine months ended June 30, 2015 and 2014 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(0.9) million and $1.3 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 and nine months ended June 30, 2015 and 2014 is presented below.

	Three Months Ended June 30	
	2015	2014
	(In thousands)	
Commodity contracts	$ (1,715)	$ 1,991
Fair value adjustment for natural gas inventory designated as the hedged item	5,350	(2,258)
Total (increase) decrease in purchased gas cost	$ 3,635	$ (267)
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ 599	$ 817
Timing ineffectiveness	3,036	(1,084)
	$ 3,635	$ (267)

	Nine Months Ended June 30	
	2015	2014
	(In thousands)	
Commodity contracts	$ 5,754	$ (2,983)
Fair value adjustment for natural gas inventory designated as the hedged item	(6,291)	4,071
Total (increase) decrease in purchased gas cost	$ (537)	$ 1,088
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ 908	$ (382)
Timing ineffectiveness	(1,445)	1,470
	$ (537)	$ 1,088

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 and nine months ended June 30, 2015 and 2014 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 June 30, 2015		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (16,488)	$ (16,488)
Gain arising from ineffective portion of commodity contracts	—	11	11
Total impact on purchased gas cost	—	(16,477)	(16,477)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(137)	—	(137)
Total Impact from Cash Flow Hedges	$ (137)	$ (16,477)	$ (16,614)

	Three Months Ended June 30, 2014		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 4,209	$ 4,209
Gain arising from ineffective portion of commodity contracts	—	179	179
Total impact on purchased gas cost	—	4,388	4,388
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,057)	—	(1,057)
Total Impact from Cash Flow Hedges	$ (1,057)	$ 4,388	$ 3,331

	Nine Months Ended June 30, 2015		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (29,222)	$ (29,222)
Loss arising from ineffective portion of commodity contracts	—	(316)	(316)
Total impact on purchased gas cost	—	(29,538)	(29,538)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(717)	—	(717)
Total Impact from Cash Flow Hedges	$ (717)	$ (29,538)	$ (30,255)

	Nine Months Ended June 30, 2014		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 8,783	$ 8,783
Gain arising from ineffective portion of commodity contracts	—	203	203
Total impact on purchased gas cost	—	8,986	8,986
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(3,172)	—	(3,172)
Total Impact from Cash Flow Hedges	$ (3,172)	$ 8,986	$ 5,814

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 and nine months ended June 30, 2015 and 2014. 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 June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$ 54,388	$ (24,111)	$ (30,436)	$ (38,559)
Forward commodity contracts	1,505	96	(37,397)	11,805
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	87	671	455	2,014
Forward commodity contracts	10,058	(2,567)	17,826	(5,357)
Total other comprehensive income (loss) from hedging, net of tax[1]	$ 66,038	$ (25,911)	$ (49,552)	$ (30,097)

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

Deferred gains (losses) recorded in AOCI associated with our 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 June 30, 2015. 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	$ (347)	$ (16,952)	$ (17,299)
Thereafter	(18,390)	(4,293)	(22,683)
Total[1]	$ (18,737)	$ (21,245)	$ (39,982)

[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 June 30, 2015 and 2014 was an (increase) decrease in purchased gas cost of $3.7 million and $(0.6) million. For the nine months ended June 30, 2015 and 2014, purchased gas cost (increased) decreased by $13.2 million and $(10.7) 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 regulated distribution segment are not designated as hedges. However, there is no earnings impact on our regulated 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 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, 2014	$ 7,662	$ (18,381)	$ (1,674)	$ (12,393)
Other comprehensive income (loss) before reclassifications	30	(30,436)	(37,397)	(67,803)
Amounts reclassified from accumulated other comprehensive income	(326)	455	17,826	17,955
Net current-period other comprehensive income (loss)	(296)	(29,981)	(19,571)	(49,848)
June 30, 2015	$ 7,366	$ (48,362)	$ (21,245)	$ (62,241)

	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 (loss) before reclassifications	3,212	(38,559)	11,805	(23,542)
Amounts reclassified from accumulated other comprehensive income	(693)	2,014	(5,357)	(4,036)
Net current-period other comprehensive income (loss)	2,519	(36,545)	6,448	(27,578)
June 30, 2014	$ 7,967	$ 1,361	$ 1,972	$ 11,300

The following tables detail reclassifications out of AOCI for the three and nine months ended June 30, 2015 and 2014. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended June 30, 2015	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 508	Operation and maintenance expense
	508	Total before tax
	(186)	Tax expense
	$ 322	Net of tax
Cash flow hedges		
Interest rate agreements	$ (137)	Interest charges
Commodity contracts	(16,488)	Purchased gas cost
	(16,625)	Total before tax
	6,480	Tax benefit
	$ (10,145)	Net of tax
Total reclassifications	$ (9,823)	Net of tax

	Three Months Ended June 30, 2014		
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**		**Affected Line Item in the Statement of Income**
	(In thousands)		
Available-for-sale securities	$	733	Operation and maintenance expense
		733	Total before tax
		(267)	Tax expense
	$	466	Net of tax
Cash flow hedges			
Interest rate agreements	$	(1,057)	Interest charges
Commodity contracts		4,209	Purchased gas cost
		3,152	Total before tax
		(1,256)	Tax expense
	$	1,896	Net of tax
Total reclassifications	$	2,362	Net of tax

	Nine Months Ended June 30, 2015		
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**		**Affected Line Item in the Statement of Income**
	(In thousands)		
Available-for-sale securities	$	514	Operation and maintenance expense
		514	Total before tax
		(188)	Tax expense
	$	326	Net of tax
Cash flow hedges			
Interest rate agreements	$	(717)	Interest charges
Commodity contracts		(29,222)	Purchased gas cost
		(29,939)	Total before tax
		11,658	Tax benefit
	$	(18,281)	Net of tax
Total reclassifications	$	(17,955)	Net of tax

	Nine Months Ended June 30, 2014	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 1,091	Operation and maintenance expense
	1,091	Total before tax
	(398)	Tax expense
	$ 693	Net of tax
Cash flow hedges		
Interest rate agreements	$ (3,172)	Interest charges
Commodity contracts	8,783	Purchased gas cost
	5,611	Total before tax
	(2,268)	Tax expense
	$ 3,343	Net of tax
Total reclassifications	$ 4,036	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, 2014. During the nine months ended June 30, 2015, 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, 2014.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is 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 June 30, 2015 and September 30, 2014. 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)	June 30, 2015
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 1,889	$ —	$ —	$ 1,889
Nonregulated segment	—	104,206	—	(93,400)	10,806
Total financial instruments	—	106,095	—	(93,400)	12,695
Hedged portion of gas stored underground	65,717	—	—	—	65,717
Available-for-sale securities					
Money market funds	—	1,217	—	—	1,217
Registered investment companies	44,854	—	—	—	44,854
Bonds	—	33,418	—	—	33,418
Total available-for-sale securities	44,854	34,635	—	—	79,489
Total assets	$ 110,571	$ 140,730	$ —	$ (93,400)	$ 157,901
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 52,140	$ —	$ —	$ 52,140
Nonregulated segment	—	124,723	—	(124,723)	—
Total liabilities	$ —	$ 176,863	$ —	$ (124,723)	$ 52,140

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2014
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 36,140	$ —	$ —	$ 36,140
Nonregulated segment	25	68,998	—	(46,298)	22,725
Total financial instruments	25	105,138	—	(46,298)	58,865
Hedged portion of gas stored underground	40,492	—	—	—	40,492
Available-for-sale securities					
Money market funds	—	2,185	—	—	2,185
Registered investment companies	44,014	—	—	—	44,014
Bonds	—	33,414	—	—	33,414
Total available-for-sale securities	44,014	35,599	—	—	79,613
Total assets	$ 84,531	$ 140,737	$ —	$ (46,298)	$ 178,970
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 21,856	$ —	$ —	$ 21,856
Nonregulated segment	12	72,044	—	(72,056)	—
Total liabilities	$ 12	$ 93,900	$ —	$ (72,056)	$ 21,856

(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 June 30, 2015, we had $31.3 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $20.5 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $10.8 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, 2014, we had $25.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $3.1 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $22.7 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 June 30, 2015				
Domestic equity mutual funds	$ 28,023	$ 10,010	$ (163)	$ 37,870
Foreign equity mutual funds	5,279	1,705	—	6,984
Bonds	33,364	78	(24)	33,418
Money market funds	1,217	—	—	1,217
	$ 67,883	$ 11,793	$ (187)	$ 79,489
As of September 30, 2014				
Domestic equity mutual funds	$ 26,633	$ 10,136	$ —	$ 36,769
Foreign equity mutual funds	5,382	1,863	—	7,245
Bonds	33,266	161	(13)	33,414
Money market funds	2,185	—	—	2,185
	$ 67,466	$ 12,160	$ (13)	$ 79,613

At June 30, 2015 and September 30, 2014, our available-for-sale securities included $46.1 million and $46.2 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At June 30, 2015, we maintained investments in bonds that have contractual maturity dates ranging from July 2015 through September 2020.

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 June 30, 2015 and September 30, 2014:

	June 30, 2015	September 30, 2014
	(In thousands)	
Carrying Amount	$ 2,460,000	$ 2,460,000
Fair Value	$ 2,659,908	$ 2,769,541

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, 2014. During the nine months ended June 30, 2015, there were no material changes in our concentration of credit risk.

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 June 30, 2015, the related condensed consolidated statements of income and comprehensive income for the three and nine-month periods ended June 30, 2015 and 2014, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2015 and 2014. 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, 2014, 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 6, 2014, 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, 2014, 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
August 5, 2015

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, 2014.

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", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; 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 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 distribution divisions, which at June 30, 2015 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 regulated distribution divisions and to third parties.

As discussed in Note 3, we operate the Company through the following three segments:

- the *regulated distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated pipeline 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.

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, 2014 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 nine months ended June 30, 2015.

RESULTS OF OPERATIONS

Executive Summary

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 seeking to achieve positive rate outcomes that benefit both our customers and the Company.

Consolidated net income for the nine months ended June 30, 2015 increased 10 percent period over period. Positive rate outcomes in our regulated businesses and the favorable effect of colder than normal weather more than offset the effect of weather that was warmer than the prior-year period. As of June 30, 2015, we had completed 16 regulatory proceedings resulting in a $113.1 million increase in annual operating income and had three ratemaking efforts in progress seeking $7.1 million of additional annual operating income.

Colder than normal weather in both fiscal years and residential and commercial consumption after the winter heating season during fiscal 2015 drove higher throughput in our regulated operations. Before adjusting for weather normalization mechanisms, weather was eight percent colder than normal during the nine months ended June 30, 2015. However, weather was nine percent warmer than the prior year nine-month period; therefore, regulated distribution sales volumes decreased eight percent due to decreased customer consumption as a result of warmer weather in the current year. Additionally, a period-over-period reduction in natural gas market volatility reduced realized gross margin in our nonregulated segment by $11.2 million.

Capital expenditures for the first nine months of fiscal 2015 were $667.5 million. Approximately 80 percent was invested to improve the safety and reliability of our distribution and transportation systems, with a significant portion of this investment incurred under regulatory mechanisms that reduce lag to six months or less. We expect our capital expenditures to range between $900 million and $1 billion for fiscal 2015. We funded our capital expenditure program primarily through operating cash flows of $717.6 million and net short-term borrowings.

On July 1, 2015, Fitch Ratings (Fitch) upgraded our senior unsecured debt rating to A from A- with a ratings outlook of stable, citing Fitch's expectation of continued strong financial performance, which has been driven primarily by organic growth in our regulated distribution and regulated pipeline segments.

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 5.4 percent in the first quarter of fiscal 2015.

Consolidated Results

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2015 and 2014:

	Three Months Ended June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
	(In thousands, except per share data)			
Operating revenues	$ 686,401	$ 943,170	$ 3,485,234	$ 4,151,882
Gross profit	381,673	359,533	1,325,696	1,244,767
Operating expenses	264,066	252,928	770,154	717,362
Operating income	117,607	106,605	555,542	527,405
Miscellaneous income (expense)	634	(374)	(2,634)	(4,022)
Interest charges	27,955	31,840	85,166	95,556
Income before income taxes	90,286	74,391	467,742	427,827
Income tax expense	34,005	28,670	176,182	161,723
Net income	$ 56,281	$ 45,721	$ 291,560	$ 266,104
Diluted net income per share	$ 0.55	$ 0.45	$ 2.86	$ 2.76

Our consolidated net income during the three and nine month periods ended June 30, 2015 and 2014 was earned in each of our business segments as follows:

	Three Months Ended June 30		
	2015	2014	Change
	(In thousands)		
Regulated distribution segment	$ 22,464	$ 18,529	$ 3,935
Regulated pipeline segment	28,568	24,938	3,630
Nonregulated segment	5,249	2,254	2,995
Net income	$ 56,281	$ 45,721	$ 10,560

	Nine Months Ended June 30		
	2015	2014	Change
	(In thousands)		
Regulated distribution segment	$ 195,704	$ 170,029	$ 25,675
Regulated pipeline segment	78,285	68,493	9,792
Nonregulated segment	17,571	27,582	(10,011)
Net income	$ 291,560	$ 266,104	$ 25,456

Regulated operations represented 91 percent and 94 percent of our consolidated net income for the three and nine months ended June 30, 2015. 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 June 30		
	2015	2014	Change
	(In thousands, except per share data)		
Regulated operations	$ 51,032	$ 43,467	$ 7,565
Nonregulated operations	5,249	2,254	2,995
Net income	$ 56,281	$ 45,721	$ 10,560
Diluted EPS from regulated operations	$ 0.50	$ 0.43	$ 0.07
Diluted EPS from nonregulated operations	0.05	0.02	0.03
Consolidated diluted EPS	$ 0.55	$ 0.45	$ 0.10

	Nine Months Ended June 30		
	2015	2014	Change
	(In thousands, except per share data)		
Regulated operations	$ 273,989	238,522	$ 35,467
Nonregulated operations	17,571	27,582	(10,011)
Net income	$ 291,560	$ 266,104	$ 25,456
Diluted EPS from regulated operations	$ 2.69	$ 2.47	$ 0.22
Diluted EPS from nonregulated operations	0.17	0.29	(0.12)
Consolidated diluted EPS	$ 2.86	$ 2.76	$ 0.10

Regulated Distribution Segment

The primary factors that impact the results of our regulated 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 regulated 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 regulated 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 June 30, 2015 compared with Three Months Ended June 30, 2014

Financial and operational highlights for our regulated distribution segment for the three months ended June 30, 2015 and 2014 are presented below.

	Three Months Ended June 30		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 267,019	$ 257,665	$ 9,354
Operating expenses	210,219	203,132	7,087
Operating income	56,800	54,533	2,267
Miscellaneous income	1,045	678	367
Interest charges	19,961	23,649	(3,688)
Income before income taxes	37,884	31,562	6,322
Income tax expense	15,420	13,033	2,387
Net income	$ 22,464	$ 18,529	$ 3,935
Consolidated regulated distribution sales volumes — MMcf	36,126	39,341	(3,215)
Consolidated regulated distribution transportation volumes — MMcf	30,134	32,997	(2,863)
Total consolidated regulated distribution throughput — MMcf	66,260	72,338	(6,078)
Consolidated regulated distribution average transportation revenue per Mcf	$ 0.49	$ 0.46	$ 0.03
Consolidated regulated distribution average cost of gas per Mcf sold	$ 4.15	$ 6.61	$ (2.46)

Income for our regulated distribution segment increased 21 percent, primarily due to a $9.4 million increase in gross profit, partially offset by a $7.1 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $16.2 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky/Mid-States and West Texas Divisions.
- a $1.3 million decrease in consumption associated with an eight percent decrease in sales volumes. Current quarter weather was 31 percent warmer than the prior-year quarter, before adjusting for weather normalization mechanisms.
- A $4.4 million decrease in revenue-related taxes, offset by a corresponding $4.3 million decrease in the related tax expense.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased operation and maintenance expenses due to increased employee-related expenses and depreciation expense associated with increased capital investments.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the three months ended June 30, 2015 and 2014. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30		
	2015	2014	Change
	(In thousands)		
Mid-Tex	$ 33,473	$ 26,100	$ 7,373
Kentucky/Mid-States	10,104	5,724	4,380
Louisiana	6,561	7,713	(1,152)
West Texas	5,018	3,785	1,233
Mississippi	1,546	(1,520)	3,066
Colorado-Kansas	1,872	1,369	503
Other	(1,774)	11,362	(13,136)
Total	$ 56,800	$ 54,533	$ 2,267

Nine Months Ended June 30, 2015 compared with Nine Months Ended June 30, 2014

Financial and operational highlights for our regulated distribution segment for the nine months ended June 30, 2015 and 2014 are presented below.

	Nine Months Ended June 30		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 997,066	$ 942,024	$ 55,042
Operating expenses	617,451	596,832	20,619
Operating income	379,615	345,192	34,423
Miscellaneous income (expense)	(1,221)	304	(1,525)
Interest charges	60,914	69,802	(8,888)
Income before income taxes	317,480	275,694	41,786
Income tax expense	121,776	105,665	16,111
Net income	$ 195,704	$ 170,029	$ 25,675
Consolidated regulated distribution sales volumes — MMcf	265,503	288,702	(23,199)
Consolidated regulated distribution transportation volumes — MMcf	107,205	105,608	1,597
Total consolidated regulated distribution throughput — MMcf	372,708	394,310	(21,602)
Consolidated regulated distribution average transportation revenue per Mcf	$ 0.49	$ 0.47	$ 0.02
Consolidated regulated distribution average cost of gas per Mcf sold	$ 5.26	$ 5.92	$ (0.66)

Income for our regulated distribution segment increased 15 percent, primarily due to a $55.0 million increase in gross profit, partially offset by a $20.6 million increase in operating expenses. The period-over-period increase in gross profit primarily reflects:

- a $61.5 million net increase in rate adjustments, primarily in our Mid-Tex, West Texas, Kentucky/Mid-States and Colorado-Kansas Divisions.
- a $3.6 million increase in transportation revenue. Transportation volumes increased two percent due to increased economic activity experienced in our Kentucky/Mid-States Division and increased consumption in our West Texas Division due to colder than normal weather.
- a $9.2 million decrease in consumption associated with an eight percent decrease in sales volumes. Current period weather was nine percent warmer compared to the prior-year period, before adjusting for weather normalization mechanisms.
- a $2.0 million decrease in revenue-related taxes primarily in our Mid-Tex Division.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased depreciation expense associated with increased capital investments and increased taxes, other than income, primarily due to increases in ad valorem and franchise taxes.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the nine months ended June 30, 2015 and 2014. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2015	2014	Change
		(In thousands)	
Mid-Tex	$ 166,586	$ 151,009	$ 15,577
Kentucky/Mid-States	59,256	53,243	6,013
Louisiana	47,380	51,131	(3,751)
West Texas	33,820	27,591	6,229
Mississippi	37,356	31,457	5,899
Colorado-Kansas	29,129	26,785	2,344
Other	6,088	3,976	2,112
Total	$ 379,615	$ 345,192	$ 34,423

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 nine months of fiscal 2015, we completed 15 regulatory proceedings, resulting in a $75.9 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Infrastructure programs	$ 11,264
Annual rate filing mechanisms	63,873
Rate case filings	711
Other rate activity	78
	$ 75,926

Additionally, the following ratemaking efforts seeking $7.1 million in annual operating income were in progress as of June 30, 2015:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Louisiana	Rate Stabilization Clause[1]	LGS	$ 1,674
Colorado-Kansas	Rate Case	Colorado	5,276
Kentucky/Mid-States	SAVE	Virginia	163
			$ 7,113

(1) On July 1, 2015, an operating income increase of $1.3 million was implemented.

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 June 30, 2015, we had infrastructure programs approved in Kansas, Kentucky, Louisiana, Texas and Virginia. The following table summarizes our infrastructure program filings with effective dates occurring during the nine months ended June 30, 2015.

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2015 Infrastructure Programs:				
West Texas - Environs	12/31/2014	$ 48,616	$ 697	06/12/2015
Mid-Tex - Environs	12/31/2014	225,611	1,158	06/01/2015
West Texas - Cities	12/31/2014	59,452	4,593	05/01/2015
Colorado-Kansas - Kansas	09/30/2014	2,708	301	02/01/2015
Kentucky/Mid-States - Kentucky	09/30/2015	35,382	4,382	10/10/2014
Kentucky/Mid-States - Virginia	09/30/2015	1,553	133	10/01/2014
Total 2015 Infrastructure Programs		$ 373,322	$ 11,264	

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 June 30, 2015, we had formula rate filings or mechanisms in our Louisiana, Mississippi and Tennessee 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, the RRM in our West Texas Division, stable rate/supplemental growth filings in the Mississippi Division, the rate stabilization clause in the Louisiana Division and Annual Rate Mechanism (ARM) in Tennessee. The following formula rate filings or mechanisms were completed during the nine months ended June 30, 2015.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2015 Filings:				
Mid-Tex	Cities	12/31/2014	$ 16,801	06/01/2015
Mid-Tex	Dallas	09/30/2014	4,420	06/01/2015
Louisiana	Trans La	09/30/2014	(286)	04/01/2015
West Texas	West Texas Cities	09/30/2014	4,300	03/15/2015
Mississippi	Mississippi-SRF	10/31/2015	4,441	02/01/2015
Mississippi	Mississippi-SGR (1)	10/31/2015	782	11/01/2014
Mid-Tex	Cities(2)	12/31/2013	33,415	06/01/2014
Total 2015 Filings			$ 63,873	

(1) The Mississippi Supplemental Growth Rider (SGR) permits the Company to incur up to $5.0 million in eligible industrial growth projects each year beyond the division's normal main extension policies. This is the second year of the SGR program.

(2) Mid-Tex Cities RRM rates were put into effect on June 1, 2014, subject to refund. The Company appealed the Mid-Tex Cities decision to deny the 2013 RRM increase to the Texas Railroad Commission on May 30, 2014. Following a proposal for decision from the Texas Railroad Commission, the Company and the Mid-Tex Cities reached a settlement that left the previously implemented rates in place. The rates became permanent on June 1, 2015.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service safely to our customers. The following table summarizes the rate cases that were completed during the nine months ended June 30, 2015.

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2015 Rate Case Filings:			
Kentucky/Mid-States	Tennessee	$ 711	06/01/2015
Total 2015 Rate Case Filings		$ 711	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2015.

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2015 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$ 78	02/01/2015
Total 2015 Other Rate Activity			$ 78	

(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.

Regulated Pipeline Segment

Our regulated pipeline segment consists of the 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 to third parties customary in the pipeline industry including parking arrangements, lending arrangements and sales of excess gas.

Our regulated pipeline 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 June 30, 2015 compared with Three Months Ended June 30, 2014

Financial and operational highlights for our regulated pipeline segment for the three months ended June 30, 2015 and 2014 are presented below.

	Three Months Ended June 30		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 71,989	$ 63,313	$ 8,676
Third-party transportation	22,724	20,413	2,311
Storage and park and lend services	664	1,086	(422)
Other	1,631	2,377	(746)
Gross profit	97,008	87,189	9,819
Operating expenses	44,581	38,905	5,676
Operating income	52,427	48,284	4,143
Miscellaneous expense	(211)	(489)	278
Interest charges	8,299	9,162	(863)
Income before income taxes	43,917	38,633	5,284
Income tax expense	15,349	13,695	1,654
Net income	$ 28,568	$ 24,938	$ 3,630
Gross pipeline transportation volumes — MMcf	165,898	160,038	5,860
Consolidated pipeline transportation volumes — MMcf	134,823	127,979	6,844

Net income for our regulated pipeline segment increased 15 percent, primarily due to a $9.8 million increase in gross profit, partially offset by a $5.7 million increase in operating expenses. The increase in gross profit primarily reflects a $9.5 million increase in rates from the approved 2014 and 2015 GRIP filings. Additionally, gross profit reflects increased pipeline demand fees and through-system transportation volumes and rates that were offset by lower storage and blending fees.

Operating expenses increased $5.7 million, primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system and increased depreciation expense associated with increased capital investments.

On April 8, 2015, a GRIP filing was approved by the RRC for $37.2 million of additional annual operating income, effective with bills rendered on and after April 8, 2015.

Nine Months Ended June 30, 2015 compared with Nine Months Ended June 30, 2014

	Nine Months Ended June 30		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 192,734	$ 163,818	$ 28,916
Third-party transportation	71,203	56,457	14,746
Storage and park and lend services	2,737	4,336	(1,599)
Other	5,631	7,534	(1,903)
Gross profit	272,305	232,145	40,160
Operating expenses	125,270	96,173	29,097
Operating income	147,035	135,972	11,063
Miscellaneous expense	(842)	(2,751)	1,909
Interest charges	25,014	27,274	(2,260)
Income before income taxes	121,179	105,947	15,232
Income tax expense	42,894	37,454	5,440
Net income	$ 78,285	$ 68,493	$ 9,792
Gross pipeline transportation volumes — MMcf	567,906	559,824	8,082
Consolidated pipeline transportation volumes — MMcf	381,828	362,583	19,245

Net income for our regulated pipeline segment increased 14 percent, primarily due to a $40.2 million increase in gross profit, partially offset by a $29.1 million increase in operating expenses. The increase in gross profit primarily reflects a $37.2 million increase in rates from the approved 2014 and 2015 GRIP filings. Additionally, gross profit reflects increased pipeline demand fees and through-system transportation volumes and rates that were offset by lower park and lend, storage and blending fees and the absence of a $1.8 million increase recorded in the prior-year associated with the renewal of an annual adjustment mechanism.

Operating expenses increased $29.1 million, primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system and increased depreciation expense associated with increased capital investments, along with the absence of a $6.7 million refund received in the prior year as a result of the completion of a state use tax audit.

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and, historically, have represented 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 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.
- The collection of accounts receivable from customers, which could affect the level of bad debt expense recognized by this segment and
- 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 June 30, 2015 compared with Three Months Ended June 30, 2014

Financial and operating highlights for our nonregulated segment for the three months ended June 30, 2015 and 2014 are presented below.

	Three Months Ended June 30		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 10,648	$ 7,871	$ 2,777
Storage and transportation services	3,607	3,603	4
Other	1,508	4,004	(2,496)
Total realized margins	15,763	15,478	285
Unrealized margins	2,016	(665)	2,681
Gross profit	17,779	14,813	2,966
Operating expenses	9,399	11,025	(1,626)
Operating income	8,380	3,788	4,592
Miscellaneous income	345	1,018	(673)
Interest charges	240	610	(370)
Income before income taxes	8,485	4,196	4,289
Income tax expense	3,236	1,942	1,294
Net income	$ 5,249	$ 2,254	$ 2,995
Gross nonregulated delivered gas sales volumes — MMcf	89,052	96,119	(7,067)
Consolidated nonregulated delivered gas sales volumes — MMcf	75,929	82,074	(6,145)
Net physical position (Bcf)	22.1	6.6	15.5

The $3.0 million quarter-over-quarter increase in gross profit reflects a $0.3 million increase in realized margins, combined with a $2.7 million increase in unrealized margins. The $0.3 million increase in realized margins primarily reflects:

- A $2.8 million increase in gas delivery and related services margins, primarily due to an increase in per-unit margins from 8 cents to 12 cents per Mcf, partially offset by a seven percent decrease in consolidated sales volumes. AEH elected not to renew excess transportation capacity in certain markets in late fiscal 2014 and early 2015. As a result, AEH has experienced fewer deliveries to low-margin marketing and power generation customers, which is the primary driver for the decrease in consolidated sales volumes and higher per-unit margins.
- A $2.5 million decrease in other realized margins, primarily due to increased storage fees and the timing of financial settlements in the current-year quarter.

Unrealized margins increased $2.7 million, primarily due to the quarter-over-quarter timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses decreased $1.6 million, primarily due to lower employee-related expenses.

Nine Months Ended June 30, 2015 compared with Nine Months Ended June 30, 2014

	Nine Months Ended June 30		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 39,280	$ 32,783	$ 6,497
Storage and transportation services	10,273	10,815	(542)
Other	(1,322)	15,831	(17,153)
Total realized margins	48,231	59,429	(11,198)
Unrealized margins	8,493	11,539	(3,046)
Gross profit	56,724	70,968	(14,244)
Operating expenses	27,832	24,727	3,105
Operating income	28,892	46,241	(17,349)
Miscellaneous income	897	1,785	(888)
Interest charges	706	1,840	(1,134)
Income before income taxes	29,083	46,186	(17,103)
Income tax expense	11,512	18,604	(7,092)
Net income	$ 17,571	$ 27,582	$ (10,011)
Gross nonregulated delivered gas sales volumes — MMcf	319,423	343,451	(24,028)
Consolidated nonregulated delivered gas sales volumes — MMcf	272,260	294,678	(22,418)
Net physical position (Bcf)	22.1	6.6	15.5

The $14.2 million period-over-period decrease in gross profit reflects an $11.2 million decrease in realized margins, combined with a $3.0 million decrease in unrealized margins. The $11.2 million decrease in realized margins primarily reflects:

- A $17.2 million decrease in other realized margins, primarily due to lower natural gas price volatility. In the prior-year period, strong market demand caused by significantly colder-than-normal weather resulted in increased market volatility. These market conditions created the opportunity to accelerate physical withdrawals that had been planned for later in the fiscal year into the second quarter to capture incremental gross profit margin. Market conditions in the current-year period were less volatile than the prior-year period, which provided fewer opportunities to capture incremental gross profit.
- A $6.5 million increase in gas delivery and related services margins, due to the absence in the current-year period of losses incurred in the prior-year period to meet peaking requirements for certain customers, which caused per-unit margins to rise from 10 cents per Mcf in the prior-year period to 12 cents per Mcf in the current-year period and fewer deliveries to low-margin marketing and power generation customers as described above. The reduction in these deliveries combined with warmer weather during the current-year period compared to the prior-year period contributed to an eight percent decline in sales volumes.

Unrealized margins decreased $3.0 million, primarily due to the period-over-period timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses increased $3.1 million, primarily due to higher legal expenses as a result of the prior-year dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 10 to the Form 10-K for the fiscal year ended September 30, 2014, partially offset by lower employee-related costs.

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 continue to fund our growth through the use of operating cash flows, debt and equity securities while maintaining a balanced capital structure. To support our capital market activities, we have a shelf registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. As of June 30, 2015, approximately $845 million of securities remained available for issuance under the shelf registration statement until March 28, 2016.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2015, September 30, 2014 and June 30, 2014:

	June 30, 2015		September 30, 2014		June 30, 2014	
	(In thousands, except percentages)					
Short-term debt	$ 251,977	4.2%	$ 196,695	3.4%	$ —	—%
Long-term debt	2,455,303	41.3%	2,455,986	42.8%	2,455,907	44.1%
Shareholders' equity	3,238,255	54.5%	3,086,232	53.8%	3,116,685	55.9%
Total	$ 5,945,535	100.0%	$ 5,738,913	100.0%	$ 5,572,592	100.0%

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 nine months ended June 30, 2015 and 2014 are presented below.

	Nine Months Ended June 30		
	2015	2014	Change
	(In thousands)		
Total cash provided by (used in)			
Operating activities	$ 717,582	$ 630,210	$ 87,372
Investing activities	(668,602)	(553,220)	(115,382)
Financing activities	(48,085)	(91,768)	43,683
Change in cash and cash equivalents	895	(14,778)	15,673
Cash and cash equivalents at beginning of period	42,258	66,199	(23,941)
Cash and cash equivalents at end of period	$ 43,153	$ 51,421	$ (8,268)

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 regulated distribution segment resulting from changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the nine months ended June 30, 2015, we generated cash flow of $717.6 million from operating activities compared with $630.2 million for the nine months ended June 30, 2014. The $87.4 million increase in operating cash flows primarily reflects successful rate case outcomes in the prior year, the timing of gas cost recoveries under our purchased gas cost mechanisms and lower gas prices during the current-year storage injection season.

Cash flows from investing activities

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, substantially all of our regulated 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.

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. Over the last two fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our systems. Our ongoing construction program enables us to enhance the safety and reliability of the systems used to provide regulated 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.

We anticipate our annual capital spending will be in the range of $900 million to $1.1 billion through fiscal 2018 as we continue to invest in the safety and reliability of our distribution and transportation systems. Where possible, we will also continue to focus our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system.

For the nine months ended June 30, 2015, capital expenditures were $667.5 million, compared with $552.6 million in the prior-year period. The $114.9 million increase primarily reflects:

- A $68.5 million increase in capital spending in our regulated distribution segment, which primarily reflects the timing of the spending combined with a planned increase in safety and reliability investment in fiscal 2015.
- A $47.4 million increase in capital spending in our regulated pipeline segment, primarily related to the enhancement and fortification of two storage fields to ensure the reliability of gas service to our Mid-Tex Division.

Cash flows from financing activities

For the nine months ended June 30, 2015, our financing activities used $48.1 million of cash compared with $91.8 million used in the prior-year period. The $43.7 million decrease of cash used is primarily due to timing between short-term debt borrowings and repayments during the current year, proceeds from the issuance of $500 million unsecured 4.125% senior notes in October 2014 and the settlement of the associated forward starting interest rate swaps, partially offset by the repayment of $500 million 4.95% senior unsecured notes at maturity on October 15, 2014, compared with short-term debt borrowings and repayments in the prior year and proceeds generated from the equity offering completed in February 2014.

The following table summarizes our share issuances for the nine months ended June 30, 2015 and 2014.

	Nine Months Ended June 30	
	2015	**2014**
Shares Issued:		
Direct Stock Purchase Plan	137,049	41,907
1998 Long-Term Incentive Plan	664,074	653,130
Retirement Savings Plan and Trust	296,067	—
Outside Directors Stock-for-Fee Plan	—	1,354
February 2014 Offering	—	9,200,000
Total shares issued	1,097,190	9,896,391

The year-over-year decrease in the number of shares issued reflects the equity offering completed in February 2014, partially offset by the fact that we have begun issuing shares for use by the Direct Stock Purchase Plan and the Retirement Savings Plan and Trust rather than using shares purchased in the open market. For the nine months ended June 30, 2015 and 2014, we canceled and retired 148,464 and 190,134 shares attributable to federal income tax 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 $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.3 billion of working capital funding. As of June 30, 2015, the amount available to us under our credit facilities, net of outstanding letters of credit, was $1.1 billion.

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 (Fitch). As of June 30, 2015, S&P and Moody's maintained a stable outlook while Fitch maintained a positive outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Senior unsecured long-term debt	A-	A2	A-
Commercial paper	A-2	P-1	F-2

On July 1, 2015, Fitch upgraded our senior unsecured debt rating to A from A- with a ratings outlook of stable, citing Fitch's expectation of continued strong financial performance, which has been driven primarily by organic growth in our regulated distribution and regulated pipeline segments.

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 June 30, 2015. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments

Except as noted in Note 7 to the unaudited condensed consolidated financial statements, there were no significant changes in our contractual obligations and commercial commitments during the nine months ended June 30, 2015.

Risk Management Activities

We conduct risk management activities through our regulated distribution and nonregulated segments. In our regulated 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. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

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 regulated distribution segment's financial instruments for the nine months ended June 30, 2015 and 2014:

	Three Months Ended June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
	(In thousands)			
Fair value of contracts at beginning of period	$ (137,710)	$ 89,411	$ 14,284	$ 109,648
Contracts realized/settled	(48)	23	(33,859)	5,220
Fair value of new contracts	1,514	(902)	1,365	(36)
Other changes in value	85,993	(39,019)	(32,041)	(65,319)
Fair value of contracts at end of period	$ (50,251)	$ 49,513	$ (50,251)	$ 49,513

The fair value of our regulated distribution segment's financial instruments at June 30, 2015 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2015				
	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	$ (4,136)	$ (46,115)	$ —	$ —	$ (50,251)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (4,136)	$ (46,115)	$ —	$ —	$ (50,251)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the nine months ended June 30, 2015 and 2014:

	Three Months Ended June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
	(In thousands)			
Fair value of contracts at beginning of period	$ (36,140)	$ 5,796	$ (3,033)	$ (14,700)
Contracts realized/settled	11,502	(3,220)	23,013	11,358
Fair value of new contracts	—	—	—	—
Other changes in value	4,121	762	(40,497)	6,680
Fair value of contracts at end of period	(20,517)	3,338	(20,517)	3,338
Netting of cash collateral	31,323	9,689	31,323	9,689
Cash collateral and fair value of contracts at period end	$ 10,806	$ 13,027	$ 10,806	$ 13,027

The fair value of our nonregulated segment's financial instruments at June 30, 2015 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2015				
	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	$ (15,066)	$ (5,298)	$ (153)	$ —	$ (20,517)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (15,066)	$ (5,298)	$ (153)	$ —	$ (20,517)

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2015 and 2014, our total net periodic pension and other benefits costs were $44.2 million and $53.5 million. A substantial portion of those costs relating to our regulated 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 2015 costs were determined using a September 30, 2014 measurement date. As of September 30, 2014, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2013, the measurement date for our fiscal 2014 net periodic cost. Therefore, we decreased the discount rate used to measure our fiscal 2015 net periodic cost from 4.95 percent to 4.43 percent. We maintained our expected return on plan assets at 7.25 percent in the determination of our fiscal 2015 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes of these and other assumptions and the absence of a $4.5 million non-recurring settlement loss recorded during the first quarter of fiscal 2014, we expect our fiscal 2015 net periodic pension cost to decrease by approximately 10 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. Based upon that determination, we are not required to make a minimum contribution to our defined benefit plans during fiscal 2015. However, we made a voluntary contribution of $38.0 million during the third quarter of fiscal 2015.

For the nine months ended June 30, 2015 we contributed $15.0 million to our postretirement medical plans. We anticipate contributing a total of approximately $20 million to our postretirement plans during fiscal 2015.

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.

In October 2014, the Society of Actuaries released its final report on mortality tables and the mortality improvement scale to reflect increasing life expectancies in the United States. We anticipate utilizing the new mortality data in our next actuarial calculation date on September 30, 2015. We are currently evaluating the impact the updated data will have on the valuation of our defined benefit and other post-retirement benefits plans. It is expected the use of this new data will increase the total amount of liabilities reported on our balance sheet in future periods by less than five percent.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our regulated distribution, regulated pipeline and nonregulated segments for the three and nine month periods ended June 30, 2015 and 2014.

Regulated Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
METERS IN SERVICE, end of period				
Residential	2,872,584	2,751,812	2,872,584	2,751,812
Commercial	262,353	245,833	262,353	245,833
Industrial	1,518	1,466	1,518	1,466
Public authority and other	8,419	8,400	8,419	8,400
Total meters	3,144,874	3,007,511	3,144,874	3,007,511
INVENTORY STORAGE BALANCE — Bcf	42.6	39.0	42.6	39.0
SALES VOLUMES — MMcf[(1)]				
Gas sales volumes				
Residential	16,667	19,555	159,067	175,884
Commercial	15,216	15,305	87,852	92,240
Industrial	2,925	3,074	11,713	12,898
Public authority and other	1,318	1,407	6,871	7,680
Total gas sales volumes	36,126	39,341	265,503	288,702
Transportation volumes	33,743	36,321	117,019	116,064
Total throughput	69,869	75,662	382,522	404,766
OPERATING REVENUES (000's)[(1)]				
Gas sales revenues				
Residential	$ 253,033	$ 309,798	$ 1,538,771	$ 1,698,600
Commercial	114,942	154,375	666,220	748,705
Industrial	13,089	19,458	62,694	74,003
Public authority and other	8,465	10,817	46,355	54,960
Total gas sales revenues	389,529	494,448	2,314,040	2,576,268
Transportation revenues	16,506	16,216	57,635	53,972
Other gas revenues	10,759	7,043	22,504	22,292
Total operating revenues	$ 416,794	$ 517,707	$ 2,394,179	$ 2,652,532
Average transportation revenue per Mcf	$ 0.49	$ 0.45	$ 0.49	$ 0.47
Average cost of gas per Mcf sold	$ 4.15	$ 6.61	$ 5.26	$ 5.92

See footnote following these tables.

Regulated Pipeline and Nonregulated Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2015	2014	2015	2014
CUSTOMERS, end of period				
Industrial	750	736	750	736
Municipal	129	128	129	128
Other	516	524	516	524
Total	1,395	1,388	1,395	1,388
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	28.2	10.9	28.2	10.9
REGULATED PIPELINE VOLUMES — MMcf(1)	165,898	160,038	567,906	559,824
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(1)	89,052	96,119	319,423	343,451
OPERATING REVENUES (000's)(1)				
Regulated pipeline	$ 97,008	$ 87,189	$ 272,305	$ 232,145
Nonregulated	278,769	465,485	1,179,379	1,660,131
Total operating revenues	$ 375,777	$ 552,674	$ 1,451,684	$ 1,892,276

Note to preceding tables:

(1) 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, 2014. During the nine months ended June 30, 2015, 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 June 30, 2015 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 third quarter of the fiscal year ended September 30, 2015 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 nine months ended June 30, 2015, 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, 2014. 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: August 5, 2015

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.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2015

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 ☑ 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 ☑ 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 ☑ 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 ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of May 1, 2015.

Class	Shares Outstanding
No Par Value	101,018,788

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
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

	March 31, 2015	September 30, 2014
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 8,789,599	$ 8,447,700
Less accumulated depreciation and amortization	1,763,521	1,721,794
Net property, plant and equipment	7,026,078	6,725,906
Current assets		
Cash and cash equivalents	95,525	42,258
Accounts receivable, net	511,830	343,400
Gas stored underground	143,154	278,917
Other current assets	67,128	111,265
Total current assets	817,637	775,840
Goodwill	742,029	742,029
Deferred charges and other assets	340,900	350,929
	$ 8,926,644	$ 8,594,704
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2015 — 100,986,227 shares; September 30, 2014 — 100,388,092 shares	$ 505	$ 502
Additional paid-in capital	2,192,100	2,180,151
Retained earnings	1,075,177	917,972
Accumulated other comprehensive loss	(128,088)	(12,393)
Shareholders' equity	3,139,694	3,086,232
Long-term debt	2,455,217	2,455,986
Total capitalization	5,594,911	5,542,218
Current liabilities		
Accounts payable and accrued liabilities	295,589	308,086
Other current liabilities	497,927	405,869
Short-term debt	224,986	196,695
Total current liabilities	1,018,502	910,650
Deferred income taxes	1,338,755	1,286,616
Regulatory cost of removal obligation	441,655	445,387
Pension and postretirement liabilities	350,889	340,963
Deferred credits and other liabilities	181,932	68,870
	$ 8,926,644	$ 8,594,704

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31 2015	Three Months Ended March 31 2014
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 1,130,613	$ 1,290,960
Regulated pipeline segment	91,730	73,615
Nonregulated segment	438,322	758,215
Intersegment eliminations	(120,597)	(157,936)
	1,540,068	1,964,854
Purchased gas cost		
Regulated distribution segment	724,378	905,772
Regulated pipeline segment	—	—
Nonregulated segment	415,416	720,626
Intersegment eliminations	(120,464)	(157,821)
	1,019,330	1,468,577
Gross profit	520,738	496,277
Operating expenses		
Operation and maintenance	133,460	124,675
Depreciation and amortization	68,022	61,307
Taxes, other than income	69,046	60,215
Total operating expenses	270,528	246,197
Operating income	250,210	250,080
Miscellaneous expense	(1,561)	(1,516)
Interest charges	27,447	31,601
Income before income taxes	221,202	216,963
Income tax expense	83,518	83,596
Net income	$ 137,684	$ 133,367
Basic net income per share	$ 1.35	$ 1.38
Diluted net income per share	$ 1.35	$ 1.38
Cash dividends per share	$ 0.39	$ 0.37
Weighted average shares outstanding:		
Basic	101,746	96,174
Diluted	101,746	96,176

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2015	2014
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 1,977,385	$ 2,134,825
Regulated pipeline segment	175,297	144,956
Nonregulated segment	900,610	1,194,646
Intersegment eliminations	(254,459)	(265,715)
	2,798,833	3,208,712
Purchased gas cost		
Regulated distribution segment	1,247,338	1,450,466
Regulated pipeline segment	—	—
Nonregulated segment	861,665	1,138,491
Intersegment eliminations	(254,193)	(265,479)
	1,854,810	2,323,478
Gross profit	944,023	885,234
Operating expenses		
Operation and maintenance	252,042	240,432
Depreciation and amortization	135,615	121,776
Taxes, other than income	118,431	102,226
Total operating expenses	506,088	464,434
Operating income	437,935	420,800
Miscellaneous expense	(3,268)	(3,648)
Interest charges	57,211	63,716
Income before income taxes	377,456	353,436
Income tax expense	142,177	133,053
Net income	235,279	220,383
Basic net income per share	$ 2.31	$ 2.34
Diluted net income per share	$ 2.31	$ 2.34
Cash dividends per share	$ 0.78	$ 0.74
Weighted average shares outstanding:		
Basic	101,667	94,013
Diluted	101,667	94,015

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31		Six Months Ended March 31	
	2015	2014	2015	2014
	(Unaudited) (In thousands)			
Net income	$ 137,684	$ 133,367	$ 235,279	$ 220,383
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $484, $(133), $(129) and $1,302	962	(252)	(105)	2,142
Cash flow hedges:				
Amortization and unrealized loss on interest rate agreements, net of tax of $(18,778), $(15,546), $(48,546) and $(7,533)	(32,669)	(27,047)	(84,456)	(13,105)
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $(1,395), $703, $(20,091) and $5,702	(2,182)	1,101	(31,134)	8,919
Total other comprehensive loss	(33,889)	(26,198)	(115,695)	(2,044)
Total comprehensive income	$ 103,795	$ 107,169	$ 119,584	$ 218,339

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2015	2014
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 235,279	$ 220,383
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	135,615	121,776
Charged to other accounts	566	441
Deferred income taxes	131,292	119,710
Other	10,332	10,746
Net assets / liabilities from risk management activities	(29,091)	836
Net change in operating assets and liabilities	56,855	17,089
Net cash provided by operating activities	540,848	490,981
Cash Flows From Investing Activities		
Capital expenditures	(441,644)	(359,009)
Other, net	(1,346)	(4,904)
Net cash used in investing activities	(442,990)	(363,913)
Cash Flows From Financing Activities		
Net increase (decrease) in short-term debt	21,839	(369,012)
Net proceeds from equity offering	—	390,205
Net proceeds from issuance of long-term debt	493,538	—
Settlement of interest rate agreements	13,364	—
Repayment of long-term debt	(500,000)	—
Cash dividends paid	(78,074)	(71,380)
Repurchase of equity awards	(7,985)	(6,317)
Issuance of common stock	12,727	(23)
Net cash used in financing activities	(44,591)	(56,527)
Net increase in cash and cash equivalents	53,267	70,541
Cash and cash equivalents at beginning of period	42,258	66,199
Cash and cash equivalents at end of period	$ 95,525	$ 136,740

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2015

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 pipeline businesses as well as other nonregulated natural gas businesses. Historically, our regulated businesses have generated over 90 percent of our consolidated net income.

Through our regulated 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 distribution divisions, which at March 31, 2015, covered service areas located in eight states. 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 North Texas 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 regulated 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.

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, 2014. 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, 2014. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2015 are not indicative of our results of operations for the full 2015 fiscal year, which ends September 30, 2015.

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, 2014.

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

During the second quarter of fiscal 2015, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

In May 2014, the FASB issued a comprehensive new revenue recognition standard that will supersede virtually all existing revenue recognition guidance under generally accepted accounting principles in the United States. Under the new standard, a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under current guidance. The new standard is currently scheduled to become effective for us beginning on October 1, 2017 and can be applied either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. On April 1, 2015, the FASB voted to propose to defer the effective date of the new standard by one year. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In April 2015, the FASB issued guidance to simplify the presentation of debt issuance costs which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The new standard will be effective for us beginning on October 1, 2016, retrospectively. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

There were no other significant changes to our accounting policies during the six months ended March 31, 2015 that will become applicable to the Company in future periods.

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 March 31, 2015 and September 30, 2014 included the following:

	March 31, 2015	September 30, 2014
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$ 153,381	$ 162,777
Merger and integration costs, net	4,461	4,730
Deferred gas costs	2,577	20,069
Rate case costs	1,114	3,757
Infrastructure Mechanisms[2]	45,339	26,948
APT annual adjustment mechanism	—	8,479
Recoverable loss on reacquired debt	17,598	18,877
Other	6,528	4,672
	$ 230,998	$ 250,309
Regulatory liabilities:		
Deferred gas costs	$ 135,069	$ 35,063
Deferred franchise fees	8,175	5,268
Regulatory cost of removal obligation	489,166	490,448
APT annual adjustment mechanism	1,072	—
Other	13,301	14,980
	$ 646,783	$ 545,759

(1) Includes $16.4 million and $18.8 million of pension and postretirement expense deferred pursuant to regulatory authorization.

(2) Infrastructure mechanisms are regulatory rules in Texas and Louisiana that allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, including the recording of interest 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

We operate the Company through the following three segments:

- The *regulated distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated pipeline 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 regulated distribution segment operations are geographically dispersed, they are reported as a single segment as each regulated 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, 2014. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six month periods ended March 31, 2015 and 2014 by segment are presented in the following tables:

	Three Months Ended March 31, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,128,473	$ 24,477	$ 387,118	$ —	$ 1,540,068
Intersegment revenues	2,140	67,253	51,204	(120,597)	—
	1,130,613	91,730	438,322	(120,597)	1,540,068
Purchased gas cost	724,378	—	415,416	(120,464)	1,019,330
Gross profit	406,235	91,730	22,906	(133)	520,738
Operating expenses					
Operation and maintenance	103,425	22,842	7,326	(133)	133,460
Depreciation and amortization	55,153	11,747	1,122	—	68,022
Taxes, other than income	62,939	5,238	869	—	69,046
Total operating expenses	221,517	39,827	9,317	(133)	270,528
Operating income	184,718	51,903	13,589	—	250,210
Miscellaneous income (expense)	(937)	(379)	252	(497)	(1,561)
Interest charges	19,313	8,391	240	(497)	27,447
Income before income taxes	164,468	43,133	13,601	—	221,202
Income tax expense	62,615	15,451	5,452	—	83,518
Net income	$ 101,853	$ 27,682	$ 8,149	$ —	$ 137,684
Capital expenditures	$ 145,990	$ 34,360	$ (19)	$ —	$ 180,331

	Three Months Ended March 31, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,289,429	$ 21,002	$ 654,423	$ —	$ 1,964,854
Intersegment revenues	1,531	52,613	103,792	(157,936)	—
	1,290,960	73,615	758,215	(157,936)	1,964,854
Purchased gas cost	905,772	—	720,626	(157,821)	1,468,577
Gross profit	385,188	73,615	37,589	(115)	496,277
Operating expenses					
Operation and maintenance	106,776	16,595	1,419	(115)	124,675
Depreciation and amortization	50,020	10,156	1,131	—	61,307
Taxes, other than income	60,606	(1,232)	841	—	60,215
Total operating expenses	217,402	25,519	3,391	(115)	246,197
Operating income	167,786	48,096	34,198	—	250,080
Miscellaneous income (expense)	97	(1,081)	443	(975)	(1,516)
Interest charges	22,828	9,155	593	(975)	31,601
Income before income taxes	145,055	37,860	34,048	—	216,963
Income tax expense	56,312	13,751	13,533	—	83,596
Net income	$ 88,743	$ 24,109	$ 20,515	$ —	$ 133,367
Capital expenditures	$ 139,555	$ 39,000	$ (113)	$ —	$ 178,442

	Six Months Ended March 31, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,973,877	$ 45,028	$ 779,928	$ —	$ 2,798,833
Intersegment revenues	3,508	130,269	120,682	(254,459)	—
	1,977,385	175,297	900,610	(254,459)	2,798,833
Purchased gas cost	1,247,338	—	861,665	(254,193)	1,854,810
Gross profit	730,047	175,297	38,945	(266)	944,023
Operating expenses					
Operation and maintenance	190,410	47,457	14,441	(266)	252,042
Depreciation and amortization	110,239	23,129	2,247	—	135,615
Taxes, other than income	106,583	10,103	1,745	—	118,431
Total operating expenses	407,232	80,689	18,433	(266)	506,088
Operating income	322,815	94,608	20,512	—	437,935
Miscellaneous income (expense)	(2,266)	(631)	552	(923)	(3,268)
Interest charges	40,953	16,715	466	(923)	57,211
Income from before income taxes	279,596	77,262	20,598	—	377,456
Income tax expense	106,356	27,545	8,276	—	142,177
Net income	$ 173,240	$ 49,717	$ 12,322	$ —	$ 235,279
Capital expenditures	$ 312,237	$ 129,114	$ 293	$ —	$ 441,644

	Six Months Ended March 31, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,131,861	$ 42,172	$ 1,034,679	$ —	$ 3,208,712
Intersegment revenues	2,964	102,784	159,967	(265,715)	—
	2,134,825	144,956	1,194,646	(265,715)	3,208,712
Purchased gas cost	1,450,466	—	1,138,491	(265,479)	2,323,478
Gross profit	684,359	144,956	56,155	(236)	885,234
Operating expenses					
Operation and maintenance	196,439	33,895	10,334	(236)	240,432
Depreciation and amortization	99,571	19,942	2,263	—	121,776
Taxes, other than income	97,690	3,431	1,105	—	102,226
Total operating expenses	393,700	57,268	13,702	(236)	464,434
Operating income	290,659	87,688	42,453	—	420,800
Miscellaneous income (expense)	(374)	(2,262)	767	(1,779)	(3,648)
Interest charges	46,153	18,112	1,230	(1,779)	63,716
Income before income taxes	244,132	67,314	41,990	—	353,436
Income tax expense	92,632	23,759	16,662	—	133,053
Net income	$ 151,500	$ 43,555	$ 25,328	$ —	$ 220,383
Capital expenditures	$ 267,061	$ 91,921	$ 27	$ —	$ 359,009

Balance sheet information at March 31, 2015 and September 30, 2014 by segment is presented in the following tables:

	March 31, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,401,722	$ 1,567,618	$ 56,738	$ —	$ 7,026,078
Investment in subsidiaries	983,075	—	(2,096)	(980,979)	—
Current assets					
Cash and cash equivalents	82,732	—	12,793	—	95,525
Assets from risk management activities	364	—	16,583	—	16,947
Other current assets	514,627	13,710	497,411	(320,583)	705,165
Intercompany receivables	814,495	—	—	(814,495)	—
Total current assets	1,412,218	13,710	526,787	(1,135,078)	817,637
Goodwill	574,816	132,502	34,711	—	742,029
Deferred charges and other assets	320,918	14,592	5,390	—	340,900
	$ 8,692,749	$ 1,728,422	$ 621,530	$ (2,116,057)	$ 8,926,644
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,139,694	$ 532,329	$ 450,746	$ (983,075)	$ 3,139,694
Long-term debt	2,455,217	—	—	—	2,455,217
Total capitalization	5,594,911	532,329	450,746	(983,075)	5,594,911
Current liabilities					
Short-term debt	529,586	—	—	(304,600)	224,986
Liabilities from risk management activities	5,769	—	—	—	5,769
Other current liabilities	649,355	13,129	139,150	(13,887)	787,747
Intercompany payables	—	783,147	31,348	(814,495)	—
Total current liabilities	1,184,710	796,276	170,498	(1,132,982)	1,018,502
Deferred income taxes	948,589	398,589	(8,423)	—	1,338,755
Noncurrent liabilities from risk management activities	132,305	—	—	—	132,305
Regulatory cost of removal obligation	441,655	—	—	—	441,655
Pension and postretirement liabilities	350,889	—	—	—	350,889
Deferred credits and other liabilities	39,690	1,228	8,709	—	49,627
	$ 8,692,749	$ 1,728,422	$ 621,530	$ (2,116,057)	$ 8,926,644

	September 30, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,202,761	$ 1,464,572	$ 58,573	$ —	$ 6,725,906
Investment in subsidiaries	952,171	—	(2,096)	(950,075)	—
Current assets					
Cash and cash equivalents	33,303	—	8,955	—	42,258
Assets from risk management activities	23,102	—	22,725	—	45,827
Other current assets	490,408	14,009	526,161	(342,823)	687,755
Intercompany receivables	790,442	—	—	(790,442)	—
Total current assets	1,337,255	14,009	557,841	(1,133,265)	775,840
Goodwill	574,816	132,502	34,711	—	742,029
Noncurrent assets from risk management activities	13,038	—	—	—	13,038
Deferred charges and other assets	309,965	21,826	6,100	—	337,891
	$ 8,390,006	$ 1,632,909	$ 655,129	$ (2,083,340)	$ 8,594,704
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,086,232	$ 482,612	$ 469,559	$ (952,171)	$ 3,086,232
Long-term debt	2,455,986	—	—	—	2,455,986
Total capitalization	5,542,218	482,612	469,559	(952,171)	5,542,218
Current liabilities					
Short-term debt	522,695	—	—	(326,000)	196,695
Liabilities from risk management activities	1,730	—	—	—	1,730
Other current liabilities	559,765	24,790	142,397	(14,727)	712,225
Intercompany payables	—	763,635	26,807	(790,442)	—
Total current liabilities	1,084,190	788,425	169,204	(1,131,169)	910,650
Deferred income taxes	913,260	361,688	11,668	—	1,286,616
Noncurrent liabilities from risk management activities	20,126	—	—	—	20,126
Regulatory cost of removal obligation	445,387	—	—	—	445,387
Pension and postretirement liabilities	340,963	—	—	—	340,963
Deferred credits and other liabilities	43,862	184	4,698	—	48,744
	$ 8,390,006	$ 1,632,909	$ 655,129	$ (2,083,340)	$ 8,594,704

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 and six months ended March 31, 2015 and 2014 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2015	2014	2015	2014
	(In thousands, except per share amounts)			
Basic Earnings Per Share				
Net income	$ 137,684	$ 133,367	$ 235,279	$ 220,383
Less: Income allocated to participating securities	296	334	520	572
Income available to common shareholders	$ 137,388	$ 133,033	$ 234,759	$ 219,811
Basic weighted average shares outstanding	101,746	96,174	101,667	94,013
Net income per share - Basic	$ 1.35	$ 1.38	$ 2.31	$ 2.34
Diluted Earnings Per Share				
Net income available to common shareholders	$ 137,388	$ 133,033	234,759	219,811
Effect of dilutive stock options and other shares	—	—	—	—
Net income available to common shareholders	$ 137,388	$ 133,033	234,759	219,811
Basic weighted average shares outstanding	101,746	96,174	101,667	94,013
Additional dilutive stock options and other shares	—	2	—	2
Diluted weighted average shares outstanding	101,746	96,176	101,667	94,015
Net income per share - Diluted	$ 1.35	$ 1.38	$ 2.31	$ 2.34

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2014 as their exercise price was less than the average market price of the common stock during those periods. As of March 31, 2015 there were no outstanding options.

2014 Equity Offering

On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock, including the underwriters' exercise of their overallotment option of 1,200,000 shares under our existing shelf registration statement. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our commercial paper program, fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

2011 Share Repurchase Program

We did not repurchase any shares during the six months ended March 31, 2015 and 2014 under our 2011 share repurchase program, which is scheduled to end on September 30, 2016.

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, 2014. Except as noted below, there were no material changes in the terms of our debt instruments during the six months ended March 31, 2015.

Long-term debt

Long-term debt at March 31, 2015 and September 30, 2014 consisted of the following:

	March 31, 2015	September 30, 2014
	(In thousands)	
Unsecured 4.95% Senior Notes, due October 2014	$ —	$ 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
Unsecured 4.125% Senior Notes, due 2044	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	4,783	4,014
	$ 2,455,217	$ 2,455,986

On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million unsecured 4.95% senior notes. The effective rate of these notes is 4.086%, after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps. The net proceeds of approximately $494 million were used to repay our $500 million 4.95% senior unsecured notes at maturity on October 15, 2014.

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 $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1.3 billion of working capital funding. At March 31, 2015 and September 30, 2014 a total of $225.0 million and $196.7 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 $1.3 billion of working capital funding, including a five-year $1.25 billion unsecured facility with an accordion feature, which, if utilized would increase the borrowing capacity to $1.5 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 March 31, 2015.

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 lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2015.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, has one uncommitted $25 million 364-day bilateral credit facility and one committed $15 million 364-day bilateral credit facility that expire in December 2015. 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 $34.9 million at March 31, 2015.

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. Applicable state regulatory commissions have approved our use of this facility through December 31, 2015.

Shelf Registration

We filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013 that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. At March 31, 2015, $845 million of securities remain available for issuance under the shelf registration statement until March 28, 2016.

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 March 31, 2015, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 48 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 March 31, 2015. 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 and six months ended March 31, 2015 and 2014 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 executive officers, we recognized a settlement loss of $4.5 million associated with our Supplemental Executive Benefits Plan (SEBP). In association with his retirement, on October 2, 2013, we made a $16.8 million benefit payment from the SEBP.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 5,051	$ 4,738	$ 3,896	$ 4,196
Interest cost	6,698	6,824	3,597	3,988
Expected return on assets	(6,437)	(5,900)	(1,608)	(1,292)
Amortization of transition obligation	—	—	68	68
Amortization of prior service credit	(47)	(34)	(411)	(362)
Amortization of actuarial loss	3,916	3,930	—	158
Net periodic pension cost	$ 9,181	$ 9,558	$ 5,542	$ 6,756

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 10,102	$ 9,476	$ 7,792	$ 8,392
Interest cost	13,397	13,648	7,193	7,976
Expected return on assets	(12,873)	(11,801)	(3,216)	(2,584)
Amortization of transition obligation	—	—	136	136
Amortization of prior service credit	(96)	(68)	(822)	(725)
Amortization of actuarial loss	7,833	7,862	—	316
Settlement loss	—	4,539	—	—
Net periodic pension cost	$ 18,363	$ 23,656	$ 11,083	$ 13,511

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2015 and 2014 are as follows:

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Discount rate	4.43%	4.95%	4.43%	4.95%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.25%	7.25%	4.60%	4.60%

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, 2015. Based on that determination, we are not required to make a minimum contribution to our defined benefit plans. However, we are planning to make a voluntary contribution between $30 and $35 million during the third quarter of fiscal 2015.

We contributed $10.2 million to our other post-retirement benefit plans during the six months ended March 31, 2015. We expect to contribute a total of approximately $20 million to $25 million to these plans during all of fiscal 2015.

In October 2014, the Society of Actuaries released its final report on mortality tables and the mortality improvement scale to reflect increasing life expectancies in the United States. We anticipate utilizing the new mortality data in our next actuarial calculation date on September 30, 2015. We are currently evaluating the impact the updated data will have on the valuation of our defined benefit and other post-retirement benefits plans. It is expected the use of this new data will increase the total amount of liabilities reported on our balance sheet in future periods by less than five percent.

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, 2014, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2015.

We are a party to various 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 March 31, 2015, AEH was committed to purchase 100.1 Bcf within one year, 24.1 Bcf within one to three years and 0.3 Bcf after three years under indexed contracts. AEH is committed to purchase 5.8 Bcf within one year under fixed price contracts with prices ranging from $2.00 to $4.25 per Mcf. Purchases under these contracts totaled $339.1 million and $621.1 million for the three months ended March 31, 2015 and 2014 and $722.1 million and $971.3 million for the six months ended March 31, 2015 and 2014.

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

Our Mid-Tex Division also maintains a limited number of long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at prices indexed to natural gas distribution hubs. At March 31, 2015, we were committed to purchase 42.9 Bcf within one year and 43.6 Bcf within one to three years under indexed contracts. Purchases under these contracts totaled $58.7 million for the three months ended March 31, 2015 and $113.3 million for the six months ended March 31, 2015. There were no long-term supply contracts as of March 31, 2014.

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts as of March 31, 2015 are as follows (in thousands):

2015	$ 5,390
2016	6,142
2017	4,239
2018	2,687
2019	1,428
Thereafter	1,607
	$ 21,493

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 March 31, 2015, a rate case was in progress in our Tennessee service area, annual rate filing mechanisms were in progress in Louisiana and Texas and infrastructure programs were in progress in Texas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

8. Financial Instruments

We currently use financial instruments in our regulated distribution and nonregulated segments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments, which have been tailored to our regulated distribution and nonregulated segments, and the related accounting for these financial instruments are fully described in Notes 2 and 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2014. During the six months ended March 31, 2015 there were no changes in our objectives, strategies and accounting for using financial instruments. 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. The following summarizes those objectives and strategies.

Regulated Commodity Risk Management Activities

Our purchased gas cost adjustment mechanisms essentially insulate our regulated distribution segment from commodity price risk; however, 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.

We typically seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2014-2015 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 37 percent, or 28.2 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Nonregulated Commodity Risk Management Activities

Our nonregulated segment is exposed to risks associated with changes in the market price of natural gas through the purchase, sale and delivery of natural gas to its customers at competitive prices. 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. Specifically, these operations use financial instruments in the following ways:

- *Gas delivery and related services* - Certain financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, are used to mitigate the commodity price risk associated with deliveries under fixed-priced forward contracts to either deliver gas to customers or purchase gas from suppliers. These financial instruments have maturity dates ranging from one to 55 months.
- *Transportation and storage services* - Our nonregulated operations 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.
- *Aggregating and purchasing gas supply* - Certain financial instruments, designated as fair value hedges, are used to hedge our natural gas inventory used in asset optimization activities.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

As of March 31, 2015, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $250 million and $450 million unsecured senior notes in fiscal 2017 and fiscal 2019, at 3.37% and 3.78%, which we designated as cash flow hedges at the time the swaps were executed. As of March 31, 2015, we had $18.8 million of net realized losses in accumulated other comprehensive income (AOCI) associated with the settlement of financial instruments used to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes, which will be recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these settled amounts extend through fiscal 2045.

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 March 31, 2015, 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 March 31, 2015, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Regulated Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(14,445)
	Cash Flow	—	62,098
	Not designated	7,533	86,114
		7,533	133,767

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 March 31, 2015 and September 30, 2014. 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.

		Regulated Distribution		Nonregulated	
	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In thousands)			
March 31, 2015					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 15,488	$ (47,615)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	170	(11,731)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(132,305)	—	—
Total		—	(132,305)	15,658	(59,346)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	364	(5,769)	132,609	(127,434)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	9,921	(7,548)
Total		364	(5,769)	142,530	(134,982)
Gross Financial Instruments		364	(138,074)	158,188	(194,328)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(158,188)	158,188
Net Financial Instruments		364	(138,074)	—	(36,140)
Cash collateral		—	—	16,583	36,140
Net Assets/Liabilities from Risk Management Activities		$ 364	$ (138,074)	$ 16,583	$ —

	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2014					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 8,912	$ (7,082)
Interest rate contracts	Other current assets / Other current liabilities	21,869	—	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	757	(2,459)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	12,608	(19,835)	—	—
Total		34,477	(19,835)	9,669	(9,541)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	1,233	(1,730)	43,677	(47,729)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	430	(291)	15,677	(14,786)
Total		1,663	(2,021)	59,354	(62,515)
Gross Financial Instruments		36,140	(21,856)	69,023	(72,056)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(69,023)	69,023
Net Financial Instruments		36,140	(21,856)	—	(3,033)
Cash collateral		—	—	22,725	3,033
Net Assets/Liabilities from Risk Management Activities		$ 36,140	$ (21,856)	$ 22,725	$ —

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of purchased gas cost 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 March 31, 2015 and 2014 we recognized losses arising from fair value and cash flow hedge ineffectiveness of $2.3 million and $3.7 million. For the six months ended March 31, 2015 and 2014 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(4.5) million and $1.4 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2015 and 2014 is presented below.

	Three Months Ended March 31	
	2015	2014
	(In thousands)	
Commodity contracts	$ (7,622)	$ 3,587
Fair value adjustment for natural gas inventory designated as the hedged item	5,142	(7,450)
Total increase in purchased gas cost	$ (2,480)	$ (3,863)
The increase in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (678)	$ (579)
Timing ineffectiveness	(1,802)	(3,284)
	$ (2,480)	$ (3,863)

	Six Months Ended March 31	
	2015	2014
	(In thousands)	
Commodity contracts	$ 7,469	$ (4,974)
Fair value adjustment for natural gas inventory designated as the hedged item	(11,641)	6,329
Total (increase) decrease in purchased gas cost	$ (4,172)	$ 1,355
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ 309	$ (1,199)
Timing ineffectiveness	(4,481)	2,554
	$ (4,172)	$ 1,355

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 and six months ended March 31, 2015 and 2014 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 March 31, 2015		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (13,078)	$ (13,078)
Gain arising from ineffective portion of commodity contracts	—	163	163
Total impact on purchased gas cost	—	(12,915)	(12,915)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(136)	—	(136)
Total Impact from Cash Flow Hedges	$ (136)	$ (12,915)	$ (13,051)

	Three Months Ended March 31, 2014		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 7,184	$ 7,184
Gain arising from ineffective portion of commodity contracts	—	142	142
Total impact on purchased gas cost	—	7,326	7,326
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,057)	—	(1,057)
Total Impact from Cash Flow Hedges	$ (1,057)	$ 7,326	$ 6,269

	Six Months Ended March 31, 2015		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (12,734)	$ (12,734)
Loss arising from ineffective portion of commodity contracts	—	(327)	(327)
Total impact on purchased gas cost	—	(13,061)	(13,061)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(580)	—	(580)
Total Impact from Cash Flow Hedges	$ (580)	$ (13,061)	$ (13,641)

	Six Months Ended March 31, 2014		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 4,574	$ 4,574
Gain arising from ineffective portion of commodity contracts	—	24	24
Total impact on purchased gas cost	—	4,598	4,598
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(2,115)	—	(2,115)
Total Impact from Cash Flow Hedges	$ (2,115)	$ 4,598	$ 2,483

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 and six months ended March 31, 2015 and 2014. 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 March 31		Six Months Ended March 31	
	2015	2014	2015	2014
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$ (32,755)	$ (27,718)	$ (84,824)	$ (14,448)
Forward commodity contracts	(10,160)	5,483	(38,902)	11,709
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	86	671	368	1,343
Forward commodity contracts	7,978	(4,382)	7,768	(2,790)
Total other comprehensive income (loss) from hedging, net of tax[1]	$ (34,851)	$ (25,946)	$ (115,590)	$ (4,186)

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

Deferred gains (losses) recorded in AOCI associated with our 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 March 31, 2015. 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	$ (347)	$ (25,826)	$ (26,173)
Thereafter	(18,477)	(6,982)	(25,459)
Total[1]	$ (18,824)	$ (32,808)	$ (51,632)

(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 March 31, 2015 and 2014 was an (increase) decrease in purchased gas cost of $8.7 million and $(9.3) million. For the six months ended March 31, 2015 and 2014 purchased gas cost (increased) decreased by $9.6 million and $(10.1) 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 regulated distribution segment are not designated as hedges. However, there is no earnings impact on our regulated 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 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, 2014	$ 7,662	$ (18,381)	$ (1,674)	$ (12,393)
Other comprehensive income (loss) before reclassifications	(101)	(84,824)	(38,902)	(123,827)
Amounts reclassified from accumulated other comprehensive income	(4)	368	7,768	8,132
Net current-period other comprehensive income (loss)	(105)	(84,456)	(31,134)	(115,695)
March 31, 2015	$ 7,557	$ (102,837)	$ (32,808)	$ (128,088)

	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 (loss) before reclassifications	2,369	(14,448)	11,709	(370)
Amounts reclassified from accumulated other comprehensive income	(227)	1,343	(2,790)	(1,674)
Net current-period other comprehensive income (loss)	2,142	(13,105)	8,919	(2,044)
March 31, 2014	$ 7,590	$ 24,801	$ 4,443	$ 36,834

The following tables detail reclassifications out of AOCI for the three and six months ended March 31, 2015 and 2014. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended March 31, 2015	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ —	Operation and maintenance expense
	—	Total before tax
	—	Tax expense
	$ —	Net of tax
Cash flow hedges		
Interest rate agreements	$ (136)	Interest charges
Commodity contracts	(13,078)	Purchased gas cost
	(13,214)	Total before tax
	5,150	Tax benefit
	$ (8,064)	Net of tax
Total reclassifications	$ (8,064)	Net of tax

Accumulated Other Comprehensive Income Components	Three Months Ended March 31, 2014 — Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$ 358	Operation and maintenance expense
	358	Total before tax
	(131)	Tax expense
	$ 227	Net of tax
Cash flow hedges		
Interest rate agreements	$ (1,057)	Interest charges
Commodity contracts	7,184	Purchased gas cost
	6,127	Total before tax
	(2,416)	Tax expense
	$ 3,711	Net of tax
Total reclassifications	$ 3,938	Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2015 — Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$ 6	Operation and maintenance expense
	6	Total before tax
	(2)	Tax expense
	$ 4	Net of tax
Cash flow hedges		
Interest rate agreements	$ (580)	Interest charges
Commodity contracts	(12,734)	Purchased gas cost
	(13,314)	Total before tax
	5,178	Tax benefit
	$ (8,136)	Net of tax
Total reclassifications	$ (8,132)	Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2014 Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 358	Operation and maintenance expense
	358	Total before tax
	(131)	Tax expense
	$ 227	Net of tax
Cash flow hedges		
Interest rate agreements	$ (2,115)	Interest charges
Commodity contracts	4,574	Purchased gas cost
	2,459	Total before tax
	(1,012)	Tax expense
	$ 1,447	Net of tax
Total reclassifications	$ 1,674	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, 2014. During the six months ended March 31, 2015, 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, 2014.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is 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 March 31, 2015 and September 30, 2014. 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]	March 31, 2015
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 364	$ —	$ —	$ 364
Nonregulated segment	7	158,181	—	(141,605)	16,583
Total financial instruments	7	158,545	—	(141,605)	16,947
Hedged portion of gas stored underground	36,237	—	—	—	36,237
Available-for-sale securities					
Money market funds	—	151	—	—	151
Registered investment companies	46,491	—	—	—	46,491
Bonds	—	33,220	—	—	33,220
Total available-for-sale securities	46,491	33,371	—	—	79,862
Total assets	$ 82,735	$ 191,916	$ —	$ (141,605)	$ 133,046
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 138,074	$ —	$ —	$ 138,074
Nonregulated segment	7	194,321	—	(194,328)	—
Total liabilities	$ 7	$ 332,395	$ —	$ (194,328)	$ 138,074

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2014
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 36,140	$ —	$ —	$ 36,140
Nonregulated segment	25	68,998	—	(46,298)	22,725
Total financial instruments	25	105,138	—	(46,298)	58,865
Hedged portion of gas stored underground	40,492	—	—	—	40,492
Available-for-sale securities					
Money market funds	—	2,185	—	—	2,185
Registered investment companies	44,014	—	—	—	44,014
Bonds	—	33,414	—	—	33,414
Total available-for-sale securities	44,014	35,599	—	—	79,613
Total assets	$ 84,531	$ 140,737	$ —	$ (46,298)	$ 178,970
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 21,856	$ —	$ —	$ 21,856
Nonregulated segment	12	72,044	—	(72,056)	—
Total liabilities	$ 12	$ 93,900	$ —	$ (72,056)	$ 21,856

(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 March 31, 2015, we had $52.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $36.1 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $16.6 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, 2014 we had $25.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $3.1 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $22.7 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 March 31, 2015				
Domestic equity mutual funds	$ 29,275	$ 9,998	$ (76)	$ 39,197
Foreign equity mutual funds	5,512	1,782	—	7,294
Bonds	33,086	141	(7)	33,220
Money market funds	151	—	—	151
	$ 68,024	$ 11,921	$ (83)	$ 79,862
As of September 30, 2014				
Domestic equity mutual funds	$ 26,633	$ 10,136	$ —	$ 36,769
Foreign equity mutual funds	5,382	1,863	—	7,245
Bonds	33,266	161	(13)	33,414
Money market funds	2,185	—	—	2,185
	$ 67,466	$ 12,160	$ (13)	$ 79,613

At March 31, 2015 and September 30, 2014, our available-for-sale securities included $46.6 million and $46.2 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At March 31, 2015, we maintained investments in bonds that have contractual maturity dates ranging from June 2015 through September 2020.

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 March 31, 2015 and September 30, 2014:

	March 31, 2015	September 30, 2014
	(In thousands)	
Carrying Amount	$ 2,460,000	$ 2,460,000
Fair Value	$ 2,885,149	$ 2,769,541

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, 2014. During the six months ended March 31, 2015, there were no material changes in our concentration of credit risk.

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 March 31, 2015, the related condensed consolidated statements of income and comprehensive income for the three and six-month periods ended March 31, 2015 and 2014, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2015 and 2014. 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, 2014, 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 6, 2014, 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, 2014, 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
May 6, 2015

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, 2014.

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", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; 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 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 distribution divisions, which at March 31, 2015 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 regulated distribution divisions and to third parties.

As discussed in Note 3, we operate the Company through the following three segments:

- the *regulated distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated pipeline 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.

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, 2014 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 six months ended March 31, 2015.

RESULTS OF OPERATIONS

Executive Summary

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 seeking to achieve positive rate outcomes that benefit both our customers and the Company.

Consolidated net income for the six months ended March 31, 2015 increased seven percent period over period. Positive rate outcomes in our regulated businesses and the favorable effect of colder than normal weather more than offset the effect of weather that was warmer than the prior-year period. As of March 31, 2015, we had completed seven regulatory proceedings resulting in a $14.4 million increase in annual operating income and had ten ratemaking efforts in progress seeking $114.4 million of additional annual operating income. Of this amount, $33.4 million was put into effect in our Mid-Tex Division on June 1, 2014, subject to refund, as a result of its 2014 RRM filing. A proposal for decision on the 2014 RRM was received on April 29, 2015, proposing an increase in annual operating income of approximately $32.7 million. We anticipate receiving a final order by the end of the third fiscal quarter.

Colder than normal weather in both fiscal years drove higher than planned consumption and throughput in our regulated operations. Before adjusting for weather normalization mechanisms, weather was 15 percent colder than normal during the second fiscal quarter and 10 percent colder than normal during the six months ended March 31, 2015. However, weather was four percent warmer than the prior-year quarter and eight percent warmer than the prior year six-month period. Therefore, gross profit in our regulated distribution segment decreased $7.9 million and sales volumes decreased eight percent due to decreased customer consumption as a result of warmer weather in the current year. Additionally, a period-over-period reduction in natural gas market volatility reduced realized gross margin in our nonregulated segment by $11.5 million.

Capital expenditures for the first six months of fiscal 2015 were $441.6 million. Approximately 80 percent was invested to improve the safety and reliability of our distribution and transportation systems, with a significant portion of this investment incurred under regulatory mechanisms that reduce lag to six months or less. We expect our capital expenditures to range between $900 million and $1 billion for fiscal 2015, and we plan to fund our growth through the use of operating cash flows and debt and equity securities, while maintaining a balanced capital structure.

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 5.4 percent in the first quarter of fiscal 2015.

Consolidated Results

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2015 and 2014:

	Three Months Ended March 31		Six Months Ended March 31	
	2015	2014	2015	2014
	(In thousands, except per share data)			
Operating revenues	$ 1,540,068	$ 1,964,854	$ 2,798,833	$ 3,208,712
Gross profit	520,738	496,277	944,023	885,234
Operating expenses	270,528	246,197	506,088	464,434
Operating income	250,210	250,080	437,935	420,800
Miscellaneous expense	(1,561)	(1,516)	(3,268)	(3,648)
Interest charges	27,447	31,601	57,211	63,716
Income before income taxes	221,202	216,963	377,456	353,436
Income tax expense	83,518	83,596	142,177	133,053
Net income	$ 137,684	$ 133,367	$ 235,279	$ 220,383
Diluted net income per share	$ 1.35	$ 1.38	$ 2.31	$ 2.34

Our consolidated net income during the three and six month periods ended March 31, 2015 and 2014 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2015	2014	Change
	(In thousands)		
Regulated distribution segment	$ 101,853	$ 88,743	$ 13,110
Regulated pipeline segment	27,682	24,109	3,573
Nonregulated segment	8,149	20,515	(12,366)
Net income	$ 137,684	$ 133,367	$ 4,317

	Six Months Ended March 31		
	2015	2014	Change
	(In thousands)		
Regulated distribution segment	$ 173,240	$ 151,500	$ 21,740
Regulated pipeline segment	49,717	43,555	6,162
Nonregulated segment	12,322	25,328	(13,006)
Net income	$ 235,279	$ 220,383	$ 14,896

Regulated operations represented 94 percent and 95 percent of our consolidated net income for the three and six months ended March 31, 2015. 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 March 31		
	2015	2014	Change
	(In thousands, except per share data)		
Regulated operations	$ 129,535	$ 112,852	$ 16,683
Nonregulated operations	8,149	20,515	(12,366)
Net income	$ 137,684	$ 133,367	$ 4,317
Diluted EPS from regulated operations	$ 1.27	$ 1.17	$ 0.10
Diluted EPS from nonregulated operations	0.08	0.21	(0.13)
Consolidated diluted EPS	$ 1.35	$ 1.38	$ (0.03)

	Six Months Ended March 31		
	2015	2014	Change
	(In thousands, except per share data)		
Regulated operations	$ 222,957	195,055	$ 27,902
Nonregulated operations	12,322	25,328	(13,006)
Net income	$ 235,279	$ 220,383	$ 14,896
Diluted EPS from continuing regulated operations	$ 2.19	$ 2.07	$ 0.12
Diluted EPS from nonregulated operations	0.12	0.27	(0.15)
Consolidated diluted EPS	$ 2.31	$ 2.34	$ (0.03)

Regulated Distribution Segment

The primary factors that impact the results of our regulated 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 regulated 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 regulated 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 March 31, 2015 compared with Three Months Ended March 31, 2014

Financial and operational highlights for our regulated distribution segment for the three months ended March 31, 2015 and 2014 are presented below.

	Three Months Ended March 31		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 406,235	$ 385,188	$ 21,047
Operating expenses	221,517	217,402	4,115
Operating income	184,718	167,786	16,932
Miscellaneous income (expense)	(937)	97	(1,034)
Interest charges	19,313	22,828	(3,515)
Income before income taxes	164,468	145,055	19,413
Income tax expense	62,615	56,312	6,303
Net income	$ 101,853	$ 88,743	$ 13,110
Consolidated regulated distribution sales volumes — MMcf	142,455	151,083	(8,628)
Consolidated regulated distribution transportation volumes — MMcf	40,559	40,404	155
Total consolidated regulated distribution throughput — MMcf	183,014	191,487	(8,473)
Consolidated regulated distribution average transportation revenue per Mcf	$ 0.49	$ 0.48	$ 0.01
Consolidated regulated distribution average cost of gas per Mcf sold	$ 5.08	$ 6.00	$ (0.92)

Income for our regulated distribution segment increased 15 percent, primarily due to a $21.0 million increase in gross profit, partially offset by a $4.1 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $26.1 million net increase in rate adjustments, primarily in our Mid-Tex, Mississippi and West Texas Divisions.
- a $1.2 million increase in transportation revenue, primarily in our Kentucky/Mid-States and Mid-Tex Divisions.
- a $5.9 million decrease in consumption associated with a six percent decrease in sales volumes. Current quarter weather was four percent warmer than the prior-year quarter.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased depreciation expense associated with increased capital investments and increased taxes, other than income, primarily due to increases in ad valorem and franchise taxes. These increases were partially offset by lower operation and maintenance expense, largely due to lower incentive compensation expense as the current year expense is commensurate with target levels.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the three months ended March 31, 2015 and 2014. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2015	2014	Change
	(In thousands)		
Mid-Tex	$ 73,999	$ 67,805	$ 6,194
Kentucky/Mid-States	29,356	29,422	(66)
Louisiana	24,094	25,992	(1,898)
West Texas	17,704	15,764	1,940
Mississippi	21,511	20,559	952
Colorado-Kansas	17,268	16,603	665
Other	786	(8,359)	9,145
Total	$ 184,718	$ 167,786	$ 16,932

Six Months Ended March 31, 2015 compared with Six Months Ended March 31, 2014

Financial and operational highlights for our regulated distribution segment for the six months ended March 31, 2015 and 2014 are presented below.

	Six Months Ended March 31		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 730,047	$ 684,359	$ 45,688
Operating expenses	407,232	393,700	13,532
Operating income	322,815	290,659	32,156
Miscellaneous expense	(2,266)	(374)	(1,892)
Interest charges	40,953	46,153	(5,200)
Income before income taxes	279,596	244,132	35,464
Income tax expense	106,356	92,632	13,724
Net income	$ 173,240	$ 151,500	$ 21,740
Consolidated regulated distribution sales volumes — MMcf	229,377	249,361	(19,984)
Consolidated regulated distribution transportation volumes — MMcf	77,071	72,611	4,460
Total consolidated regulated distribution throughput — MMcf	306,448	321,972	(15,524)
Consolidated regulated distribution average transportation revenue per Mcf	$ 0.49	$ 0.48	$ 0.01
Consolidated regulated distribution average cost of gas per Mcf sold	$ 5.44	$ 5.82	$ (0.38)

Income for our regulated distribution segment increased 14 percent, primarily due to a $45.7 million increase in gross profit, partially offset by a $13.5 million increase in operating expenses. The period-over-period increase in gross profit primarily reflects:

- a $45.4 million net increase in rate adjustments, primarily in our Mid-Tex, West Texas, Kentucky/Mid-States and Colorado-Kansas Divisions.
- a $2.2 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $4.3 million increase in the related tax expense.
- a $3.3 million increase in transportation revenue. Transportation volumes increased six percent due to increased economic activity primarily in our West Texas and Kentucky/Mid-States Divisions.
- a $1.1 million increase in service fees attributable to customer reconnection and installment plan revenues.
- a $7.9 million decrease in consumption associated with an eight percent decrease in sales volumes. Current period weather was eight percent warmer compared to the prior-year period.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased depreciation expense associated with increased capital investments and increased taxes, other than income, primarily due to increases in ad valorem and franchise taxes. These increases were partially offset by lower operation and maintenance expense, largely due to decreased employee-related costs, primarily due to lower incentive compensation expense as the current year expense is commensurate with target levels.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the six months ended March 31, 2015 and 2014. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2015	2014	Change
		(In thousands)	
Mid-Tex	$ 133,113	$ 124,909	$ 8,204
Kentucky/Mid-States	49,152	47,519	1,633
Louisiana	40,819	43,418	(2,599)
West Texas	28,802	23,806	4,996
Mississippi	35,810	32,977	2,833
Colorado-Kansas	27,257	25,416	1,841
Other	7,862	(7,386)	15,248
Total	$ 322,815	$ 290,659	$ 32,156

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 six months of fiscal 2015, we completed seven regulatory proceedings, resulting in a $14.4 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Infrastructure programs	$ 4,816
Annual rate filing mechanisms	9,523
Rate case filings	—
Other rate activity	78
	$ 14,417

Additionally, the following ratemaking efforts seeking $77.2 million in annual operating income were in progress as of March 31, 2015:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Louisiana	Rate Stabilization Clause(1)	Trans LA	$ 473
Louisiana	Rate Stabilization Clause	LGS	1,674
Kentucky/Mid-States	Rate Case	Tennessee	5,889
Mid-Tex	2013 Rate Review Mechanism(2)	Mid-Tex Cities	33,415
Mid-Tex	2014 Rate Review Mechanism(3)	Mid-Tex Cities	22,551
Mid-Tex	Dallas Annual Review Mechanism	City of Dallas	6,718
Mid-Tex	GRIP	Mid-Tex Environs	1,158
West Texas	GRIP(4)	Cities of Amarillo, Channing, Lubbock & Dalhart	4,593
West Texas	GRIP	WT Environs	697
			$ 77,168

(1) An operating income decrease of $0.3 million was implemented on April 1, 2015

(2) Mid-Tex Cities Rate Review Mechanism (RRM) rates were put into effect on June 1, 2014, subject to refund. The Company appealed the Mid-Tex Cities decision to deny the 2013 RRM increase to the Texas Railroad Commission on May 30, 2014. A proposal for decision was received on April 29, 2015 for approximately $32.7 million.

(3) The 2014 RRM was filed on February 27, 2015 and is currently being reviewed by the Mid-Tex Cities.

(4) The 2014 GRIP increase in annual operating income of $4.6 million was implemented on April 28, 2015.

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 March 31, 2015, we had infrastructure programs approved in Kansas, Kentucky, Louisiana, Texas and Virginia. The following table summarizes our infrastructure program filings with effective dates occurring during the six months ended March 31, 2015.

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2015 Infrastructure Programs:				
Colorado-Kansas - Kansas	09/30/2014	$ 2,708	$ 301	02/01/2015
Kentucky/Mid-States - Kentucky	09/30/2015	35,382	4,382	10/10/2014
Kentucky/Mid-States - Virginia	09/30/2015	1,553	133	10/01/2014
Total 2015 Infrastructure Programs		$ 39,643	$ 4,816	

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 March 31, 2015, we had formula rate filings or 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, as the RRM in our West Texas Division, stable rate/supplemental growth filings in the Mississippi Division and the rate stabilization clause in the Louisiana Division. The following formula rate filings or mechanisms were completed during the six months ended March 31, 2015.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2015 Filings:				
West Texas	West Texas Cities	09/30/14	$ 4,300	03/15/2015
Mississippi	Mississippi-SRF	10/31/15	$ 4,441	02/01/2015
Mississippi	Mississippi-SGR [(1)]	10/31/15	$ 782	11/01/2014
Total 2015 Filings			$ 9,523	

(1) The Mississippi Supplemental Growth Rider (SGR) permits the Company to incur up to $5.0 million in eligible industrial growth projects each year beyond the division's normal main extension policies. This is the second year of the SGR program.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2015.

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2015 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[(1)]	$ 78	02/01/2015
Total 2015 Other Rate Activity			$ 78	

(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.

Regulated Pipeline Segment

Our regulated pipeline segment consists of the 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 to third parties customary in the pipeline industry including parking arrangements, lending arrangements and sales of excess gas.

Our regulated pipeline 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 March 31, 2015 compared with Three Months Ended March 31, 2014

Financial and operational highlights for our regulated pipeline segment for the three months ended March 31, 2015 and 2014 are presented below.

	Three Months Ended March 31		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 60,666	$ 50,761	$ 9,905
Third-party transportation	28,085	18,885	9,200
Storage and park and lend services	1,069	1,429	(360)
Other	1,910	2,540	(630)
Gross profit	91,730	73,615	18,115
Operating expenses	39,827	25,519	14,308
Operating income	51,903	48,096	3,807
Miscellaneous expense	(379)	(1,081)	702
Interest charges	8,391	9,155	(764)
Income before income taxes	43,133	37,860	5,273
Income tax expense	15,451	13,751	1,700
Net income	$ 27,682	$ 24,109	$ 3,573
Gross pipeline transportation volumes — MMcf	220,646	210,610	10,036
Consolidated pipeline transportation volumes — MMcf	126,371	115,830	10,541

Net income for our regulated pipeline segment increased 15 percent, primarily due to an $18.1 million increase in gross profit, partially offset by a $14.3 million increase in operating expenses. The increase in gross profit primarily reflects a $15.3 million increase in rates from the approved 2014 and 2015 GRIP filings. Additionally, gross profit reflects increased pipeline demand fees and through-system transportation volumes and rates that were offset by lower storage and blending fees.

Operating expenses increased $14.3 million, primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system and increased depreciation expense associated with increased capital investments along with the absence of a $6.7 million refund received in the prior year as a result of the completion of a state use tax audit.

On April 8, 2015, a GRIP filing was approved by the RRC for $37.2 million of additional annual operating income, effective with bills rendered on and after April 8, 2015.

Six Months Ended March 31, 2015 compared with Six Months Ended March 31, 2014

	Six Months Ended March 31		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 120,745	$ 100,505	$ 20,240
Third-party transportation	48,479	36,044	12,435
Storage and park and lend services	2,073	3,250	(1,177)
Other	4,000	5,157	(1,157)
Gross profit	175,297	144,956	30,341
Operating expenses	80,689	57,268	23,421
Operating income	94,608	87,688	6,920
Miscellaneous expense	(631)	(2,262)	1,631
Interest charges	16,715	18,112	(1,397)
Income before income taxes	77,262	67,314	9,948
Income tax expense	27,545	23,759	3,786
Net income	$ 49,717	$ 43,555	$ 6,162
Gross pipeline transportation volumes — MMcf	402,008	399,786	2,222
Consolidated pipeline transportation volumes — MMcf	247,005	234,604	12,401

Net income for our regulated pipeline segment increased 14 percent, primarily due to a $30.3 million increase in gross profit, partially offset by a $23.4 million increase in operating expenses. The increase in gross profit primarily reflects a $27.8 million increase in rates from the approved 2014 and 2015 GRIP filings. Additionally, gross profit reflects increased pipeline demand fees and through-system transportation volumes and rates that were offset by lower park and lend, storage and blending fees, and the absence of a $1.8 million increase recorded in the prior-year associated with the renewal of an annual adjustment mechanism.

Operating expenses increased $23.4 million, primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system and increased depreciation expense associated with increased capital investments, along with the aforementioned state use tax refund received in the prior year.

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and, historically, have represented 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 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.
- The collection of accounts receivable from customers, which could affect the level of bad debt expense recognized by this segment and
- 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 March 31, 2015 compared with Three Months Ended March 31, 2014

Financial and operating highlights for our nonregulated segment for the three months ended March 31, 2015 and 2014 are presented below.

	Three Months Ended March 31		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 17,873	$ 12,449	$ 5,424
Storage and transportation services	3,353	3,677	(324)
Other	3,001	19,829	(16,828)
Total realized margins	24,227	35,955	(11,728)
Unrealized margins	(1,321)	1,634	(2,955)
Gross profit	22,906	37,589	(14,683)
Operating expenses	9,317	3,391	5,926
Operating income	13,589	34,198	(20,609)
Miscellaneous income	252	443	(191)
Interest charges	240	593	(353)
Income before income taxes	13,601	34,048	(20,447)
Income tax expense	5,452	13,533	(8,081)
Net income	$ 8,149	$ 20,515	$ (12,366)
Gross nonregulated delivered gas sales volumes — MMcf	122,178	139,753	(17,575)
Consolidated nonregulated delivered gas sales volumes — MMcf	105,401	119,967	(14,566)
Net physical position (Bcf)	17.0	1.9	15.1

The $14.7 million quarter-over-quarter decrease in gross profit reflects an $11.7 million decrease in realized margins, combined with a $3.0 million decrease in unrealized margins. The $11.7 million decrease in realized margins primarily reflects:

- A $16.8 million decrease in other realized margins, primarily due to lower natural gas price volatility. In the prior-year period, strong market demand caused by significantly colder-than-normal weather resulted in increased market volatility. These market conditions created the opportunity to accelerate physical withdrawals that had been planned for later in the fiscal year into the second quarter to capture incremental gross profit margin. Current quarter market conditions were less volatile than the prior-year quarter, which provided fewer opportunities to capture incremental gross profit.
- A $5.4 million increase in gas delivery and related services margins. Consolidated sales volumes decreased 12 percent as a result of warmer weather during the current quarter compared to the prior-year quarter. However, in the prior-year quarter, we incurred losses to meet peaking requirements to certain customers, which did not recur in the current quarter. As a result, per-unit margins increased from 9 cents to 15 cents per Mcf.

Unrealized margins decreased $3.0 million, primarily due to the quarter-over-quarter timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses increased $5.9 million, primarily due to higher legal expenses as a result of the prior-year dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 10 to the Form 10-K for the fiscal year ended September 30, 2014.

Six Months Ended March 31, 2015 compared with Six Months Ended March 31, 2014

	Six Months Ended March 31		
	2015	**2014**	**Change**
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 28,632	$ 24,912	$ 3,720
Storage and transportation services	6,666	7,212	(546)
Other	(2,830)	11,827	(14,657)
Total realized margins	32,468	43,951	(11,483)
Unrealized margins	6,477	12,204	(5,727)
Gross profit	38,945	56,155	(17,210)
Operating expenses	18,433	13,702	4,731
Operating income	20,512	42,453	(21,941)
Miscellaneous income	552	767	(215)
Interest charges	466	1,230	(764)
Income before income taxes	20,598	41,990	(21,392)
Income tax expense	8,276	16,662	(8,386)
Net income	$ 12,322	$ 25,328	$ (13,006)
Gross nonregulated delivered gas sales volumes — MMcf	230,371	247,332	(16,961)
Consolidated nonregulated delivered gas sales volumes — MMcf	196,331	212,604	(16,273)
Net physical position (Bcf)	17.0	1.9	15.1

The $17.2 million period-over-period decrease in gross profit reflects an $11.5 million decrease in realized margins, combined with a $5.7 million decrease in unrealized margins. The $11.5 million decrease in realized margins primarily reflects:

- A $14.7 million decrease in other realized margins, primarily due to lower natural gas price volatility. In the prior-year period, strong market demand caused by significantly colder-than-normal weather resulted in increased market volatility. These market conditions created the opportunity to accelerate physical withdrawals that had been planned for later in the fiscal year into the second quarter to capture incremental gross profit margin. Current quarter market conditions were less volatile than the prior-year quarter, which provided fewer opportunities to capture incremental gross profit.
- A $3.7 million increase in gas delivery and related services margins, due to the absence in the current-year period of the aforementioned losses to meet peaking requirements for certain customers, which caused per-unit margins to rise from 10 cents per Mcf in the prior-year period to 12 cents per Mcf in the current-year period. Consolidated sales volumes decreased eight percent as a result of warmer weather during the current-year period compared to the prior-year period.

Unrealized margins decreased $5.7 million, primarily due to the period-over-period timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses increased $4.7 million, primarily due to higher legal expenses due to the aforementioned prior-year resolution of legal matters, partially offset by lower employee-related costs.

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 continue to fund our growth through the use of operating cash flows, debt and equity securities while maintaining a balanced capital structure. To support our capital market activities, we have a shelf registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. As of March 31, 2015, approximately $845 million of securities remained available for issuance under the shelf registration statement until March 28, 2016.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2015, September 30, 2014 and March 31, 2014:

	March 31, 2015		September 30, 2014		March 31, 2014	
			(In thousands, except percentages)			
Short-term debt	$ 224,986	3.9%	$ 196,695	3.4%	$ —	—%
Long-term debt	2,455,217	42.2%	2,455,986	42.8%	2,455,829	44.0%
Shareholders' equity	3,139,694	53.9%	3,086,232	53.8%	3,124,761	56.0%
Total	$ 5,819,897	100.0%	$ 5,738,913	100.0%	$ 5,580,590	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 46.1 percent at March 31, 2015, 46.2 percent at September 30, 2014 and 44 percent at March 31, 2014.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These 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 six months ended March 31, 2015 and 2014 are presented below.

	Six Months Ended March 31		
	2015	2014	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 540,848	$ 490,981	$ 49,867
Investing activities	(442,990)	(363,913)	(79,077)
Financing activities	(44,591)	(56,527)	11,936
Change in cash and cash equivalents	53,267	70,541	(17,274)
Cash and cash equivalents at beginning of period	42,258	66,199	(23,941)
Cash and cash equivalents at end of period	$ 95,525	$ 136,740	$ (41,215)

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 regulated distribution segment resulting from changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the six months ended March 31, 2015, we generated cash flow of $540.8 million from operating activities compared with $491.0 million for the six months ended March 31, 2014. The $49.9 million increase in operating cash flows primarily reflects the timing of gas cost recoveries under our purchased gas cost mechanisms.

Cash flows from investing activities

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, substantially all of our regulated 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.

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. Over the last two fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our systems. Our ongoing construction program enables us to enhance the safety and reliability of the systems used to provide regulated 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.

We anticipate our annual capital spending will be in the range of $900 million to $1.1 billion through fiscal 2018 as we continue to invest in the safety and reliability of our distribution and transportation system. Where possible, we will also continue to focus our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system.

For the six months ended March 31, 2015, capital expenditures were $441.6 million, compared with $359.0 million in the prior-year period. The $82.6 million increase primarily reflects:

- A $45.2 million increase in capital spending in our regulated distribution segment, which primarily reflects the timing of the spending combined with a planned increase in safety and reliability investment in fiscal 2015.
- A $37.2 million increase in capital spending in our regulated pipeline segment, primarily related to the enhancement and fortification of two storage fields to ensure the reliability of gas service to our Mid-Tex Division.

Cash flows from financing activities

For the six months ended March 31, 2015, our financing activities used $44.6 million of cash compared with $56.5 million used in the prior-year period. The $11.9 million decrease of cash used is primarily due to timing between short-term debt borrowings and repayments during the current year, proceeds from the issuance of $500 million unsecured 4.125% senior notes in October 2014 and the settlement of the associated forward starting interest rate swaps, partially offset by the repayment of $500 million 4.95% senior unsecured notes at maturity on October 15, 2014 compared with short-term debt borrowings and repayments in the prior year and proceeds generated from the equity offering completed in February 2014.

The following table summarizes our share issuances for the six months ended March 31, 2015 and 2014.

	Six Months Ended March 31	
	2015	**2014**
Shares issued:		
Direct Stock Purchase Plan	79,803	—
1998 Long-Term Incentive Plan	488,729	479,521
Retirement Savings Plan and Trust	178,067	—
Outside Directors Stock-for-Fee Plan	—	922
February 2014 Offering	—	9,200,000
Total shares issued	746,599	9,680,443

The year-over-year decrease in the number of shares issued reflects the equity offering completed in February 2014, partially offset by the fact that we have begun issuing shares for the Direct Stock Purchase Plan and the Retirement Savings Plan and Trust rather than using shares purchased in the open market. For the six months ended March 31, 2015 and 2014, we canceled and retired 148,464 and 142,829 shares attributable to federal income tax 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 $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.3 billion of working capital funding. As of March 31, 2015, the amount available to us under our credit facilities, net of outstanding letters of credit, was $1.1 billion.

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 March 31, 2015, S&P and Moody's maintained a stable outlook while Fitch maintained a positive outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Senior unsecured long-term debt	A-	A2	A-
Commercial paper	A-2	P-1	F-2

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of March 31, 2015. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments

Except as noted in Note 7 to the unaudited condensed consolidated financial statements, there were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2015.

Risk Management Activities

We conduct risk management activities through our regulated distribution and nonregulated segments. In our regulated 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. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

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 regulated distribution segment's financial instruments for the six months ended March 31, 2015 and 2014:

	Three Months Ended March 31		Six Months Ended March 31	
	2015	2014	2015	2014
	(In thousands)			
Fair value of contracts at beginning of period	$ (94,848)	$ 134,776	$ 14,284	$ 109,648
Contracts realized/settled	(10,655)	6,868	(33,811)	5,197
Fair value of new contracts	216	347	(149)	866
Other changes in value	(32,423)	(52,580)	(118,034)	(26,300)
Fair value of contracts at end of period	$ (137,710)	$ 89,411	$ (137,710)	$ 89,411

The fair value of our regulated distribution segment's financial instruments at March 31, 2015 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2015				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
			(In thousands)		
Prices actively quoted	$ (5,405)	$ (132,305)	$ —	$ —	$ (137,710)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (5,405)	$ (132,305)	$ —	$ —	$ (137,710)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the six months ended March 31, 2015 and 2014:

	Three Months Ended March 31		Six Months Ended March 31	
	2015	2014	2015	2014
	(In thousands)			
Fair value of contracts at beginning of period	$ (26,099)	$ (5,093)	$ (3,033)	$ (14,700)
Contracts realized/settled	4,346	4,635	11,511	14,578
Fair value of new contracts	—	—	—	—
Other changes in value	(14,387)	6,254	(44,618)	5,918
Fair value of contracts at end of period	(36,140)	5,796	(36,140)	5,796
Netting of cash collateral	52,723	11,054	52,723	11,054
Cash collateral and fair value of contracts at period end	$ 16,583	$ 16,850	$ 16,583	$ 16,850

The fair value of our nonregulated segment's financial instruments at March 31, 2015 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2015				
	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	$ (26,953)	$ (8,954)	$ (233)	$ —	$ (36,140)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (26,953)	$ (8,954)	$ (233)	$ —	$ (36,140)

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2015 and 2014, our total net periodic pension and other benefits costs were $29.4 million and $37.2 million. A substantial portion of those costs relating to our regulated 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 2015 costs were determined using a September 30, 2014 measurement date. As of September 30, 2014, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2013, the measurement date for our fiscal 2014 net periodic cost. Therefore, we decreased the discount rate used to measure our fiscal 2015 net periodic cost from 4.95 percent to 4.43 percent. We maintained our expected return on plan assets at 7.25 percent in the determination of our fiscal 2015 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes of these and other assumptions and the absence of a $4.5 million non-recurring settlement loss recorded during the first quarter of fiscal 2014, we expect our fiscal 2015 net periodic pension cost to decrease by approximately 10 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. Based upon that determination, we are not required to make a minimum contribution to our defined benefit plans. However, we are planning on making a voluntary contribution between $30 and $35 million during the third quarter of fiscal 2015.

For the six months ended March 31, 2015 we contributed $10.2 million to our postretirement medical plans. We anticipate contributing a total of between $20 million and $25 million to our postretirement plans during fiscal 2015.

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.

In October 2014, the Society of Actuaries released its final report on mortality tables and the mortality improvement scale to reflect increasing life expectancies in the United States. We anticipate utilizing the new mortality data in our next actuarial calculation date on September 30, 2015. We are currently evaluating the impact the updated data will have on the valuation of our defined benefit and other post-retirement benefits plans. It is expected the use of this new data will increase the total amount of liabilities reported on our balance sheet in future periods by less than five percent.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our regulated distribution, regulated pipeline and nonregulated segments for the three and six month periods ended March 31, 2015 and 2014.

Regulated Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2015	2014	2015	2014
METERS IN SERVICE, end of period				
Residential	2,864,252	2,777,135	2,864,252	2,777,135
Commercial	262,235	250,144	262,235	250,144
Industrial	1,524	1,495	1,524	1,495
Public authority and other	8,430	8,797	8,430	8,797
Total meters	3,136,441	3,037,571	3,136,441	3,037,571
INVENTORY STORAGE BALANCE — Bcf	25.0	22.6	25.0	22.6
SALES VOLUMES — MMcf[1]				
Gas sales volumes				
Residential	90,182	95,913	142,400	156,329
Commercial	43,921	45,521	72,636	76,935
Industrial	4,898	5,805	8,788	9,824
Public authority and other	3,454	3,844	5,553	6,273
Total gas sales volumes	142,455	151,083	229,377	249,361
Transportation volumes	44,441	44,319	83,276	79,743
Total throughput	186,896	195,402	312,653	329,104
OPERATING REVENUES (000's)[1]				
Gas sales revenues				
Residential	$ 744,013	$ 843,385	$ 1,285,738	$ 1,388,802
Commercial	309,648	358,907	551,278	594,330
Industrial	26,694	30,797	49,605	54,545
Public authority and other	22,892	27,694	37,890	44,143
Total gas sales revenues	1,103,247	1,260,783	1,924,511	2,081,820
Transportation revenues	21,977	20,939	41,129	37,756
Other gas revenues	5,389	9,238	11,745	15,249
Total operating revenues	$ 1,130,613	$ 1,290,960	$ 1,977,385	$ 2,134,825
Average transportation revenue per Mcf	$ 0.49	$ 0.47	$ 0.49	$ 0.47
Average cost of gas per Mcf sold	$ 5.08	$ 6.00	$ 5.44	$ 5.82

See footnote following these tables.

Regulated Pipeline and Nonregulated Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2015	2014	2015	2014
CUSTOMERS, end of period				
Industrial	750	748	750	748
Municipal	130	130	130	130
Other	522	564	522	564
Total	1,402	1,442	1,402	1,442
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	18.5	9.7	18.5	9.7
REGULATED PIPELINE VOLUMES — MMcf[1]	220,646	210,610	402,008	399,786
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[1]	122,178	139,753	230,371	247,332
OPERATING REVENUES (000's)[1]				
Regulated pipeline	$ 91,730	$ 73,615	$ 175,297	$ 144,956
Nonregulated	438,322	758,215	900,610	1,194,646
Total operating revenues	$ 530,052	$ 831,830	$ 1,075,907	$ 1,339,602

Note to preceding tables:

(1) 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, 2014. During the six months ended March 31, 2015, 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 March 31, 2015 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 second quarter of the fiscal year ended September 30, 2015 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 six months ended March 31, 2015, 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, 2014. 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: May 6, 2015

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.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended December 31, 2014

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 ☑ 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 ☑ 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 ☑ 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 ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of January 30, 2015.

Class	Shares Outstanding
No Par Value	100,862,051

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
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, 2014	September 30, 2014
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 8,661,288	$ 8,447,700
Less accumulated depreciation and amortization	1,748,747	1,721,794
Net property, plant and equipment	6,912,541	6,725,906
Current assets		
Cash and cash equivalents	123,832	42,258
Accounts receivable, net	607,421	343,400
Gas stored underground	277,916	278,917
Other current assets	109,595	111,265
Total current assets	1,118,764	775,840
Goodwill	742,029	742,029
Deferred charges and other assets	341,759	350,929
	$ 9,115,093	$ 8,594,704
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, 2014 — 100,854,217 shares; September 30, 2014 — 100,388,092 shares	$ 504	$ 502
Additional paid-in capital	2,181,645	2,180,151
Retained earnings	975,975	917,972
Accumulated other comprehensive loss	(94,199)	(12,393)
Shareholders' equity	3,063,925	3,086,232
Long-term debt	2,455,131	2,455,986
Total capitalization	5,519,056	5,542,218
Current liabilities		
Accounts payable and accrued liabilities	397,595	308,086
Other current liabilities	472,113	405,869
Short-term debt	550,903	196,695
Total current liabilities	1,420,611	910,650
Deferred income taxes	1,256,443	1,286,616
Regulatory cost of removal obligation	443,931	445,387
Pension and postretirement liabilities	345,350	340,963
Deferred credits and other liabilities	129,702	68,870
	$ 9,115,093	$ 8,594,704

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2014	2013
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 846,772	$ 843,865
Regulated pipeline segment	83,567	71,341
Nonregulated segment	462,288	436,431
Intersegment eliminations	(133,862)	(107,779)
	1,258,765	1,243,858
Purchased gas cost		
Regulated distribution segment	522,960	544,694
Regulated pipeline segment	—	—
Nonregulated segment	446,249	417,865
Intersegment eliminations	(133,729)	(107,658)
	835,480	854,901
Gross profit	423,285	388,957
Operating expenses		
Operation and maintenance	118,582	115,757
Depreciation and amortization	67,593	60,469
Taxes, other than income	49,385	42,011
Total operating expenses	235,560	218,237
Operating income	187,725	170,720
Miscellaneous expense	(1,707)	(2,132)
Interest charges	29,764	32,115
Income before income taxes	156,254	136,473
Income tax expense	58,659	49,457
Net income	$ 97,595	$ 87,016
Basic net income per share	$ 0.96	$ 0.95
Diluted net income per share	$ 0.96	$ 0.95
Cash dividends per share	$ 0.39	$ 0.37
Weighted average shares outstanding:		
Basic	101,581	91,841
Diluted	101,581	91,843

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended December 31	
	2014	**2013**
	(Unaudited) (In thousands)	
Net income	$ 97,595	$ 87,016
Other comprehensive income (loss), net of tax		
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(613) and $1,435	(1,067)	2,394
Cash flow hedges:		
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(29,768) and $8,013	(51,787)	13,942
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $(18,696) and $4,999	(28,952)	7,818
Total other comprehensive income (loss)	(81,806)	24,154
Total comprehensive income	$ 15,789	$ 111,170

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2014	2013
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 97,595	$ 87,016
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	67,593	60,469
Charged to other accounts	275	221
Deferred income taxes	55,418	47,127
Other	4,889	5,228
Net assets / liabilities from risk management activities	(20,828)	(5,477)
Net change in operating assets and liabilities	(177,527)	(160,284)
Net cash provided by operating activities	27,415	34,300
Cash Flows From Investing Activities		
Capital expenditures	(261,313)	(180,567)
Other, net	(739)	(5,867)
Net cash used in investing activities	(262,052)	(186,434)
Cash Flows From Financing Activities		
Net increase in short-term debt	350,574	320,783
Net proceeds from issuance of long-term debt	493,538	—
Settlement of interest rate agreements	13,364	—
Repayment of long-term debt	(500,000)	—
Cash dividends paid	(39,592)	(33,984)
Repurchase of equity awards	(7,985)	(6,289)
Issuance of common stock	6,312	(12)
Net cash provided by financing activities	316,211	280,498
Net increase in cash and cash equivalents	81,574	128,364
Cash and cash equivalents at beginning of period	42,258	66,199
Cash and cash equivalents at end of period	$ 123,832	$ 194,563

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2014

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 pipeline businesses as well as other nonregulated natural gas businesses. Historically, our regulated businesses have generated over 90 percent of our consolidated net income.

Through our regulated 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 distribution divisions, which at December 31, 2014, covered service areas located in eight states. 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 North Texas 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 regulated 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.

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, 2014. 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, 2014. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2014 are not indicative of our results of operations for the full 2015 fiscal year, which ends September 30, 2015.

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, 2014.

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

In May 2014, the FASB issued a comprehensive new revenue recognition standard that will supersede virtually all existing revenue recognition guidance under generally accepted accounting principles in the United States. Under the new standard, a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under current guidance. The new standard is currently scheduled to become effective for us beginning on October 1, 2017 and can be applied either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

There were no other significant changes to our accounting policies during the three months ended December 31, 2014 that will become applicable to the Company in future periods.

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, 2014 and September 30, 2014 included the following:

	December 31, 2014	September 30, 2014
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$ 158,190	$ 162,777
Merger and integration costs, net	4,595	4,730
Deferred gas costs	38,022	20,069
Rate case costs	2,427	3,757
Texas Rule 8.209[2]	36,100	26,948
APT annual adjustment mechanism	5,623	8,479
Recoverable loss on reacquired debt	18,238	18,877
Other	4,297	4,672
	$ 267,492	$ 250,309
Regulatory liabilities:		
Deferred gas costs	$ 61,530	$ 35,063
Deferred franchise fees	7,367	5,268
Regulatory cost of removal obligation	489,210	490,448
Other	13,808	14,980
	$ 571,915	$ 545,759

(1) Includes $17.7 million and $18.8 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

We operate the Company through the following three segments:

- The *regulated distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated pipeline 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 regulated distribution segment operations are geographically dispersed, they are reported as a single segment as each regulated 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, 2014. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three month periods ended December 31, 2014 and 2013 by segment are presented in the following tables:

	Three Months Ended December 31, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 845,404	$ 20,551	$ 392,810	$ —	$ 1,258,765
Intersegment revenues	1,368	63,016	69,478	(133,862)	—
	846,772	83,567	462,288	(133,862)	1,258,765
Purchased gas cost	522,960	—	446,249	(133,729)	835,480
Gross profit	323,812	83,567	16,039	(133)	423,285
Operating expenses					
Operation and maintenance	86,985	24,615	7,115	(133)	118,582
Depreciation and amortization	55,086	11,382	1,125	—	67,593
Taxes, other than income	43,644	4,865	876	—	49,385
Total operating expenses	185,715	40,862	9,116	(133)	235,560
Operating income	138,097	42,705	6,923	—	187,725
Miscellaneous income (expense)	(1,329)	(252)	300	(426)	(1,707)
Interest charges	21,640	8,324	226	(426)	29,764
Income before income taxes	115,128	34,129	6,997	—	156,254
Income tax expense	43,741	12,094	2,824	—	58,659
Net income	$ 71,387	$ 22,035	$ 4,173	$ —	$ 97,595
Capital expenditures	$ 166,247	$ 94,754	$ 312	$ —	$ 261,313

	Three Months Ended December 31, 2013				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 842,432	$ 21,170	$ 380,256	$ —	$ 1,243,858
Intersegment revenues	1,433	50,171	56,175	(107,779)	—
	843,865	71,341	436,431	(107,779)	1,243,858
Purchased gas cost	544,694	—	417,865	(107,658)	854,901
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

Balance sheet information at December 31, 2014 and September 30, 2014 by segment is presented in the following tables:

	December 31, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,310,469	$ 1,544,320	$ 57,752	$ —	$ 6,912,541
Investment in subsidiaries	949,428	—	(2,096)	(947,332)	—
Current assets					
Cash and cash equivalents	79,345	—	44,487	—	123,832
Assets from risk management activities	852	—	17,402	—	18,254
Other current assets	733,736	13,881	500,168	(271,107)	976,678
Intercompany receivables	835,928	—	—	(835,928)	—
Total current assets	1,649,861	13,881	562,057	(1,107,035)	1,118,764
Goodwill	574,816	132,502	34,711	—	742,029
Noncurrent assets from risk management activities	124	—	—	—	124
Deferred charges and other assets	316,704	19,578	5,353	—	341,635
	$ 8,801,402	$ 1,710,281	$ 657,777	$ (2,054,367)	$ 9,115,093
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,063,925	$ 504,648	$ 444,780	$ (949,428)	$ 3,063,925
Long-term debt	2,455,131	—	—	—	2,455,131
Total capitalization	5,519,056	504,648	444,780	(949,428)	5,519,056
Current liabilities					
Short-term debt	791,503	—	—	(240,600)	550,903
Liabilities from risk management activities	13,701	—	—	—	13,701
Other current liabilities	675,685	23,722	185,011	(28,411)	856,007
Intercompany payables	—	805,723	30,205	(835,928)	—
Total current liabilities	1,480,889	829,445	215,216	(1,104,939)	1,420,611
Deferred income taxes	887,452	376,018	(7,027)	—	1,256,443
Noncurrent liabilities from risk management activities	82,123	—	—	—	82,123
Regulatory cost of removal obligation	443,931	—	—	—	443,931
Pension and postretirement liabilities	345,350	—	—	—	345,350
Deferred credits and other liabilities	42,601	170	4,808	—	47,579
	$ 8,801,402	$ 1,710,281	$ 657,777	$ (2,054,367)	$ 9,115,093

	September 30, 2014				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,202,761	$ 1,464,572	$ 58,573	$ —	$ 6,725,906
Investment in subsidiaries	952,171	—	(2,096)	(950,075)	—
Current assets					
Cash and cash equivalents	33,303	—	8,955	—	42,258
Assets from risk management activities	23,102	—	22,725	—	45,827
Other current assets	490,408	14,009	526,161	(342,823)	687,755
Intercompany receivables	790,442	—	—	(790,442)	—
Total current assets	1,337,255	14,009	557,841	(1,133,265)	775,840
Goodwill	574,816	132,502	34,711	—	742,029
Noncurrent assets from risk management activities	13,038	—	—	—	13,038
Deferred charges and other assets	309,965	21,826	6,100	—	337,891
	$ 8,390,006	$ 1,632,909	$ 655,129	$ (2,083,340)	$ 8,594,704
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,086,232	$ 482,612	$ 469,559	$ (952,171)	$ 3,086,232
Long-term debt	2,455,986	—	—	—	2,455,986
Total capitalization	5,542,218	482,612	469,559	(952,171)	5,542,218
Current liabilities					
Short-term debt	522,695	—	—	(326,000)	196,695
Liabilities from risk management activities	1,730	—	—	—	1,730
Other current liabilities	559,765	24,790	142,397	(14,727)	712,225
Intercompany payables	—	763,635	26,807	(790,442)	—
Total current liabilities	1,084,190	788,425	169,204	(1,131,169)	910,650
Deferred income taxes	913,260	361,688	11,668	—	1,286,616
Noncurrent liabilities from risk management activities	20,126	—	—	—	20,126
Regulatory cost of removal obligation	445,387	—	—	—	445,387
Pension and postretirement liabilities	340,963	—	—	—	340,963
Deferred credits and other liabilities	43,862	184	4,698	—	48,744
	$ 8,390,006	$ 1,632,909	$ 655,129	$ (2,083,340)	$ 8,594,704

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, 2014 and 2013 are calculated as follows:

	Three Months Ended December 31	
	2014	2013
	(In thousands, except per share amounts)	
Basic Earnings Per Share		
Net income	$ 97,595	$ 87,016
Less: Income allocated to participating securities	216	232
Income available to common shareholders	$ 97,379	$ 86,784
Basic weighted average shares outstanding	101,581	91,841
Net income per share - Basic	$ 0.96	$ 0.95
Diluted Earnings Per Share		
Net income available to common shareholders	$ 97,379	$ 86,784
Effect of dilutive stock options and other shares	—	—
Net income available to common shareholders	$ 97,379	$ 86,784
Basic weighted average shares outstanding	101,581	91,841
Additional dilutive stock options and other shares	—	2
Diluted weighted average shares outstanding	101,581	91,843
Net income per share - Diluted	$ 0.96	$ 0.95

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 as their exercise price was less than the average market price of the common stock during those periods. As of December 31, 2014 there were no outstanding options.

2014 Equity Offering

On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock, including the underwriters' exercise of their overallotment option of 1,200,000 shares under our existing shelf registration statement. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our commercial paper program, fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

2011 Share Repurchase Program

We did not repurchase any shares during the three months ended December 31, 2014 and 2013 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, 2014. Except as noted below, there were no material changes in the terms of our debt instruments during the three months ended December 31, 2014.

Long-term debt

Long-term debt at December 31, 2014 and September 30, 2014 consisted of the following:

	December 31, 2014	September 30, 2014
	(In thousands)	
Unsecured 4.95% Senior Notes, due October 2014	$ —	$ 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
Unsecured 4.125% Senior Notes, due 2044	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	4,869	4,014
	$ 2,455,131	$ 2,455,986

On October 15, 2014, we issued $500 million of 4.125% 30-year unsecured senior notes, which replaced, on a long-term basis, our $500 million unsecured 4.95% senior notes. The effective rate of these notes is 4.086%, after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps. The net proceeds of approximately $494 million were used to repay our $500 million 4.95% senior unsecured notes at maturity on October 15, 2014.

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 $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1.3 billion of working capital funding. At December 31, 2014 and September 30, 2014 a total of $550.9 million and $196.7 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 $1.3 billion of working capital funding, including a five-year $1.25 billion unsecured facility with an accordion feature, which, if utilized would increase the borrowing capacity to $1.5 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, 2014.

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 lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2015.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, has one uncommitted \$25 million 364-day bilateral credit facility and one committed \$15 million 364-day bilateral credit facility that expire in December 2015. 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 \$31.1 million at December 31, 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, 2015.

Shelf Registration

We filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013 that originally permitted us to issue a total of \$1.75 billion in common stock and/or debt securities. At December 31, 2014, \$845 million of securities remain available for issuance under the shelf registration statement until March 28, 2016.

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, 2014, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 51 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, 2014. 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, 2014 and 2013 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 executive officers, we recognized a settlement loss of \$4.5 million associated with our Supplemental Executive Benefits Plan (SEBP). In association with his 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	
	2014	2013	2014	2013
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 5,051	$ 4,738	$ 3,896	$ 4,196
Interest cost	6,699	6,824	3,596	3,988
Expected return on assets	(6,436)	(5,901)	(1,608)	(1,292)
Amortization of transition obligation	—	—	68	68
Amortization of prior service credit	(49)	(34)	(411)	(363)
Amortization of actuarial loss	3,917	3,932	—	158
Settlement loss	—	4,539	—	—
Net periodic pension cost	$ 9,182	$ 14,098	$ 5,541	$ 6,755

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2014 and 2013 are as follows:

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
Discount rate	4.43%	4.95%	4.43%	4.95%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.25%	7.25%	4.60%	4.60%

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, 2015. Due to current market conditions, the current funded position of the plans and the funding requirements under the PPA, we were not required to make a contribution to our defined benefit plans during the first quarter of fiscal 2015, nor do we anticipate making a contribution during the remainder of the fiscal year.

We contributed $5.6 million to our other post-retirement benefit plans during the three months ended December 31, 2014. We expect to contribute a total of approximately $20 million to $25 million to these plans during all of fiscal 2015.

In October 2014, the Society of Actuaries released its final report on mortality tables and the mortality improvement scale to reflect increasing life expectancies in the United States. We anticipate utilizing the new mortality data in our next actuarial calculation date on September 30, 2015. We are currently evaluating the impact the updated data will have on the valuation of our defined benefit and other post-retirement benefits plans. It is expected the use of this new data will increase the total amount of liabilities reported on our balance sheet in future periods by less than five percent.

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, 2014, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2014.

We are a party to various 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, 2014, AEH was committed to purchase 93.2 Bcf within one year, 11.6 Bcf within one to three years and 0.4 Bcf after three years under indexed contracts. AEH is committed to purchase 5.1 Bcf within one year under fixed price contracts with prices ranging from $1.22 to $4.49 per Mcf. Purchases under these contracts totaled $383.0 million and $350.2 million for the three months ended December 31, 2014 and 2013.

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

Our Mid-Tex Division also maintains a limited number of long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at prices indexed to natural gas distribution hubs. At December 31, 2014, we were committed to purchase 47.0 Bcf within one year and 57.7 Bcf within one to three years under indexed contracts. Purchases under these contracts totaled $46.5 million, and $30.4 million for the three months ended December 31, 2014 and 2013.

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, 2014. There were no material changes to the estimated storage and transportation fees for the three months ended December 31, 2014.

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, 2014, rate cases were in progress in our Mid-Tex and Tennessee service areas, annual rate filing mechanisms were in progress in Louisiana, Texas and Mississippi and an infrastructure program and an other ratemaking 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 currently use financial instruments in our regulated distribution and nonregulated segments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments, which have been tailored to our regulated distribution and nongregulated segments, and the related accounting for these financial instruments are fully described in Notes 2 and 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2014. During the three months ended December 31, 2014 there were no changes in our objectives, strategies and accounting for using financial instruments. 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. The following summarizes those objectives and strategies.

Regulated Commodity Risk Management Activities

Our purchased gas cost adjustment mechanisms essentially insulate our regulated distribution segment from commodity price risk; however, 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.

We typically seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2014-2015 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 37 percent, or 28.2 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Nonregulated Commodity Risk Management Activities

Our nonregulated segment is exposed to risks associated with changes in the market price of natural gas through the purchase, sale and delivery of natural gas to its customers at competitive prices. 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. Specifically, these operations use financial instruments in the following ways:

- *Gas delivery and related services* - Certain financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, are used to mitigate the commodity price risk associated with deliveries under fixed-priced forward contracts to either deliver gas to customers or purchase gas from suppliers. These financial instruments have maturity dates ranging from one to 58 months.
- *Transportation and storage services* - Our nonregulated operations 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.
- *Aggregating and purchasing gas supply* - Certain financial instruments, designated as fair value hedges, are used to hedge our natural gas inventory used in asset optimization activities.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

As of December 31, 2014, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $250 million and $450 million unsecured senior notes in fiscal 2017 and fiscal 2019, at 3.37% and 3.78%, which we designated as cash flow hedges at the time the agreements were executed. As of December 31, 2014, we had $18.9 million net realized losses in accumulated other comprehensive income (AOCI) associated with the settlement of financial instruments used to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes, which will be recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these settled amounts extends through fiscal 2045.

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, 2014, 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, 2014, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Regulated Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(17,225)
	Cash Flow	—	65,720
	Not designated	16,493	76,750
		16,493	125,245

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, 2014 and September 30, 2014. 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.

		Regulated Distribution		Nonregulated	
	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In thousands)			
December 31, 2014					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 38,443	$ (62,886)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	1,123	(9,136)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(80,721)	—	—
Total		—	(80,721)	39,566	(72,022)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	852	(13,701)	179,884	(175,804)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	124	(1,402)	9,036	(6,759)
Total		976	(15,103)	188,920	(182,563)
Gross Financial Instruments		976	(95,824)	228,486	(254,585)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(228,486)	228,486
Net Financial Instruments		976	(95,824)	—	(26,099)
Cash collateral		—	—	17,402	26,099
Net Assets/Liabilities from Risk Management Activities		$ 976	$ (95,824)	$ 17,402	$ —

	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2014					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 8,912	$ (7,082)
Interest rate contracts	Other current assets / Other current liabilities	21,869	—	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	757	(2,459)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	12,608	(19,835)	—	—
Total		34,477	(19,835)	9,669	(9,541)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	1,233	(1,730)	43,677	(47,729)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	430	(291)	15,677	(14,786)
Total		1,663	(2,021)	59,354	(62,515)
Gross Financial Instruments		36,140	(21,856)	69,023	(72,056)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(69,023)	69,023
Net Financial Instruments		36,140	(21,856)	—	(3,033)
Cash collateral		—	—	22,725	3,033
Net Assets/Liabilities from Risk Management Activities		$ 36,140	$ (21,856)	$ 22,725	$ —

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, 2014 and 2013 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(2.2) million and $5.1 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, 2014 and 2013 is presented below.

	Three Months Ended December 31 2014	2013
	(In thousands)	
Commodity contracts	$ 15,090	$ (8,561)
Fair value adjustment for natural gas inventory designated as the hedged item	(16,782)	13,779
Total (increase) decrease in purchased gas cost	$ (1,692)	$ 5,218
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ 986	$ (620)
Timing ineffectiveness	(2,678)	5,838
	$ (1,692)	$ 5,218

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, 2014 and 2013 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, 2014		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 344	$ 344
Loss arising from ineffective portion of commodity contracts	—	(490)	(490)
Total impact on purchased gas cost	—	(146)	(146)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(444)	—	(444)
Total Impact from Cash Flow Hedges	$ (444)	$ (146)	$ (590)

	Three Months Ended December 31, 2013		
	Regulated 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)

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, 2014 and 2013. 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	
	2014	2013
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate agreements	$ (52,069)	$ 13,270
Forward commodity contracts	(28,742)	6,226
Recognition of (gains) losses in earnings due to settlements:		
Interest rate agreements	282	672
Forward commodity contracts	(210)	1,592
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ (80,739)	$ 21,760

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

Deferred gains (losses) recorded in AOCI associated with our 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, 2014. 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	$ (347)	$ (25,704)	$ (26,051)
Thereafter	(18,563)	(4,922)	(23,485)
Total[(1)]	$ (18,910)	$ (30,626)	$ (49,536)

(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, 2014 and 2013 was an increase (decrease) in gross profit of $0.9 million and $(0.8) 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 regulated distribution segment are not designated as hedges. However, there is no earnings impact on our regulated 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 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, 2014	$ 7,662	$ (18,381)	$ (1,674)	$ (12,393)
Other comprehensive income (loss) before reclassifications	(1,063)	(52,069)	(28,742)	(81,874)
Amounts reclassified from accumulated other comprehensive income	(4)	282	(210)	68
Net current-period other comprehensive income (loss)	(1,067)	(51,787)	(28,952)	(81,806)
December 31, 2014	$ 6,595	$ (70,168)	$ (30,626)	$ (94,199)

	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 (loss) 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 (loss)	2,394	13,942	7,818	24,154
December 31, 2013	$ 7,842	$ 51,848	$ 3,342	$ 63,032

The following tables detail reclassifications out of AOCI for the three months ended December 31, 2014 and 2013. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended December 31, 2014	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 6	Operation and maintenance expense
	6	Total before tax
	(2)	Tax expense
	$ 4	Net of tax
Cash flow hedges		
Interest rate agreements	$ (444)	Interest charges
Commodity contracts	344	Purchased gas cost
	(100)	Total before tax
	28	Tax benefit
	$ (72)	Net of tax
Total reclassifications	$ (68)	Net of tax

Accumulated Other Comprehensive Income Components	Three Months Ended December 31, 2013		
	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

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, 2014. During the three months ended December 31, 2014, 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, 2014.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is 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, 2014 and September 30, 2014. 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, 2014
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 976	$ —	$ —	$ 976
Nonregulated segment	14	228,472	—	(211,084)	17,402
Total financial instruments	14	229,448	—	(211,084)	18,378
Hedged portion of gas stored underground	49,800	—	—	—	49,800
Available-for-sale securities					
Money market funds	—	1,184	—	—	1,184
Registered investment companies	45,060	—	—	—	45,060
Bonds	—	33,548	—	—	33,548
Total available-for-sale securities	45,060	34,732	—	—	79,792
Total assets	$ 94,874	$ 264,180	$ —	$ (211,084)	$ 147,970
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 95,824	$ —	$ —	$ 95,824
Nonregulated segment	13	254,572	—	(254,585)	—
Total liabilities	$ 13	$ 350,396	$ —	$ (254,585)	$ 95,824

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2014
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 36,140	$ —	$ —	$ 36,140
Nonregulated segment	25	68,998	—	(46,298)	22,725
Total financial instruments	25	105,138	—	(46,298)	58,865
Hedged portion of gas stored underground	40,492	—	—	—	40,492
Available-for-sale securities					
Money market funds	—	2,185	—	—	2,185
Registered investment companies	44,014	—	—	—	44,014
Bonds	—	33,414	—	—	33,414
Total available-for-sale securities	44,014	35,599	—	—	79,613
Total assets	$ 84,531	$ 140,737	$ —	$ (46,298)	$ 178,970
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 21,856	$ —	$ —	$ 21,856
Nonregulated segment	12	72,044	—	(72,056)	—
Total liabilities	$ 12	$ 93,900	$ —	$ (72,056)	$ 21,856

(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, 2014, we had $43.5 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $26.1 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $17.4 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2014 we had $25.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $3.1 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $22.7 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, 2014				
Domestic equity mutual funds	$ 29,231	$ 8,956	$ (101)	$ 38,086
Foreign equity mutual funds	5,512	1,462	—	6,974
Bonds	33,474	110	(36)	33,548
Money market funds	1,184	—	—	1,184
	$ 69,401	$ 10,528	$ (137)	$ 79,792
As of September 30, 2014				
Domestic equity mutual funds	$ 26,633	$ 10,136	$ —	$ 36,769
Foreign equity mutual funds	5,382	1,863	—	7,245
Bonds	33,266	161	(13)	33,414
Money market funds	2,185	—	—	2,185
	$ 67,466	$ 12,160	$ (13)	$ 79,613

At December 31, 2014 and September 30, 2014, our available-for-sale securities included $46.2 million and $46.2 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At December 31, 2014, we maintained investments in bonds that have contractual maturity dates ranging from January 2015 through September 2020.

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, 2014 and September 30, 2014:

	December 31, 2014	September 30, 2014
	(In thousands)	
Carrying Amount	$ 2,460,000	$ 2,460,000
Fair Value	$ 2,817,435	$ 2,769,541

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, 2014. During the three months ended December 31, 2014, there were no material changes in our concentration of credit risk.

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, 2014, the related condensed consolidated statements of income and comprehensive income for the three-month periods ended December 31, 2014 and 2013, and the condensed consolidated statements of cash flows for the three-month periods ended December 31, 2014 and 2013. 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, 2014, 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 6, 2014, 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, 2014, 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 3, 2015

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, 2014.

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", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; 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 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 distribution divisions, which at December 31, 2014 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 regulated distribution divisions and to third parties.

As discussed in Note 3, we operate the Company through the following three segments:

- the *regulated distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- the *regulated pipeline 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.

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, 2014 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, 2014.

RESULTS OF OPERATIONS

Executive Summary

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 seeking to achieve positive rate outcomes that benefit both our customers and the Company.

During the first three months of fiscal 2015, we earned $97.6 million, or $0.96 per diluted share, a 12 percent increase over the first quarter of fiscal 2014. The increase primarily reflects the positive impact of rate increases received in our regulated operations during fiscal 2014. As of December 31, 2014, we had completed three regulatory proceedings in our regulated segments resulting in a $5.3 million increase in annual operating income and had seven ratemaking efforts in progress seeking $54.1 million of additional annual operating income.

Capital expenditures for the first quarter of fiscal 2015 were $261.3 million. Approximately 80 percent was invested to improve the safety and reliability of our distribution and transportation systems, and a significant portion of this investment was incurred under regulatory mechanisms that reduce lag to six months or less. We expect our capital expenditures to range between $900 million and $1 billion for fiscal 2015, and we plan to fund our growth through the use of operating cash flows and debt and equity securities, while maintaining a balanced capital structure.

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 5.4 percent in the first quarter of fiscal 2015.

Consolidated Results

The following table presents our consolidated financial highlights for the three months ended December 31, 2014 and 2013:

	Three Months Ended December 31	
	2014	2013
	(In thousands, except per share data)	
Operating revenues	$ 1,258,765	$ 1,243,858
Gross profit	423,285	388,957
Operating expenses	235,560	218,237
Operating income	187,725	170,720
Miscellaneous expense	(1,707)	(2,132)
Interest charges	29,764	32,115
Income before income taxes	156,254	136,473
Income tax expense	58,659	49,457
Net income	$ 97,595	$ 87,016
Diluted net income per share	$ 0.96	$ 0.95

Our consolidated net income during the three month periods ended December 31, 2014 and 2013 was earned in each of our business segments as follows:

	Three Months Ended December 31		
	2014	2013	Change
	(In thousands)		
Regulated distribution segment	$ 71,387	$ 62,757	$ 8,630
Regulated pipeline segment	22,035	19,446	2,589
Nonregulated segment	4,173	4,813	(640)
Net income	$ 97,595	$ 87,016	$ 10,579

Regulated operations represented 96 percent of our consolidated net income for the three months ended December 31, 2014. 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		
	2014	2013	Change
	(In thousands, except per share data)		
Regulated operations	$ 93,422	$ 82,203	$ 11,219
Nonregulated operations	4,173	4,813	(640)
Net income	$ 97,595	$ 87,016	$ 10,579
Diluted EPS from regulated operations	$ 0.92	$ 0.90	$ 0.02
Diluted EPS from nonregulated operations	0.04	0.05	(0.01)
Consolidated diluted EPS	$ 0.96	$ 0.95	$ 0.01

Regulated Distribution Segment

The primary factors that impact the results of our regulated 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 regulated 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 regulated 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, 2014 compared with Three Months Ended December 31, 2013

Financial and operational highlights for our regulated distribution segment for the three months ended December 31, 2014 and 2013 are presented below.

	Three Months Ended December 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 323,812	$ 299,171	$ 24,641
Operating expenses	185,715	176,298	9,417
Operating income	138,097	122,873	15,224
Miscellaneous expense	(1,329)	(471)	(858)
Interest charges	21,640	23,325	(1,685)
Income before income taxes	115,128	99,077	16,051
Income tax expense	43,741	36,320	7,421
Net income	$ 71,387	$ 62,757	$ 8,630
Consolidated regulated distribution sales volumes — MMcf	86,922	98,278	(11,356)
Consolidated regulated distribution transportation volumes — MMcf	36,512	32,207	4,305
Total consolidated regulated distribution throughput — MMcf	123,434	130,485	(7,051)
Consolidated regulated distribution average transportation revenue per Mcf	$ 0.49	$ 0.48	$ 0.01
Consolidated regulated distribution average cost of gas per Mcf sold	$ 6.02	$ 5.54	$ 0.48

Income for our regulated distribution segment increased 14 percent, primarily due to an $24.6 million increase in gross profit, partially offset by a $9.4 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $19.3 million net increase in rate adjustments, primarily in our Mid-Tex, West Texas and Kentucky Divisions.
- a $2.9 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $2.8 million increase in the related tax expense.
- a $2.1 million increase in transportation revenue. Transportation volumes increased 13 percent due to increased economic activity primarily in our West Texas and Kentucky/Mid-States Divisions.
- a $1.8 million increase in service fees attributable to customer reconnection and installment plan revenues.
- a $2.0 million decrease in consumption. Current quarter weather approximated normal conditions and was 14 percent warmer than the prior-year quarter. As a result, sales volumes decreased 12 percent.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased depreciation expense associated with increased capital investments and increased taxes, other than income, primarily due to increases in ad valorem and franchise taxes. These increases were partially offset by lower operation and maintenance expense, largely due to decreased legal costs.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the three months ended December 31, 2014 and 2013. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31		
	2014	**2013**	**Change**
		(In thousands)	
Mid-Tex	$ 59,114	$ 57,104	$ 2,010
Kentucky/Mid-States	19,796	18,097	1,699
Louisiana	16,725	17,426	(701)
West Texas	11,098	8,042	3,056
Mississippi	14,299	12,418	1,881
Colorado-Kansas	9,989	8,813	1,176
Other	7,076	973	6,103
Total	$ 138,097	$ 122,873	$ 15,224

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 three months of fiscal 2015, we completed three regulatory proceedings, resulting in a $5.3 million increase in annual operating income as summarized below:

Rate Action	**Annual Increase to Operating Income**
	(In thousands)
Infrastructure programs	$ 4,515
Annual rate filing mechanisms	782
Rate case filings	—
Other rate activity	—
	$ 5,297

Additionally, the following ratemaking efforts seeking $54.1 million in annual operating income were in progress as of December 31, 2014:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Ad Valorem(1)	Kansas	$ 78
Colorado-Kansas	GSRS(2)	Kansas	403
Louisiana	Rate Stabilization Clause	Trans LA	473
Kentucky/Mid-States	Rate Case	Tennessee	5,889
Mid-Tex	Rate Review Mechanism(3)	Mid-Tex Cities	33,415
Mississippi	Stable Rate Filing(4)	Mississippi	8,922
West Texas	Rate Review Mechanism	WT Cities	4,969
			$ 54,149

(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 6, 2015 approving our requested operating income increase.

(2) The Gas System Reliability Surcharge (GSRS) filing relates to a collection of qualified infrastructure in Kansas. The Commission issued an order on January 27, 2015, approving an increase of $0.3 million.

(3) Mid-Tex Cities RRM rates were put into effect on June 1, 2014, subject to refund. The Company appealed the Mid-Tex Cities decision to deny the 2013 RRM increase to the Texas Railroad Commission on May 30, 2014. A proposal for decision is expected in February 2015.

(4) The commission issued a final order on February 3, 2015 approving a $4.4 million increase in annual operating income.

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, 2014, we had infrastructure programs approved in Kansas, Kentucky, Louisiana, Texas and Virginia. The following table summarizes our infrastructure program filings with effective dates occurring during the three months ended December 31, 2014.

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2015 Infrastructure Programs:				
Kentucky/Mid-States - Kentucky	09/30/2015	$ 35,382	$ 4,382	10/10/2014
Kentucky/Mid-States - Virginia	09/30/2015	1,553	133	10/01/2014
Total 2015 Infrastructure Programs		$ 36,935	$ 4,515	

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, 2014, 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, as the RRM in our West Texas Division, stable rate/supplemental growth filings in the Mississippi Division and the rate stabilization clause in the Louisiana Division. One annual rate filing mechanism was completed during the three months ended December 31, 2014.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2015 Filings:				
Mississippi	Mississippi-SGR [1]	10/31/15	$ 782	11/01/2014
Total 2015 Filings			$ 782	

[1] The Mississippi Supplemental Growth Rider (SGR) permits the Company to pursue up to $5.0 million of eligible industrial growth projects beyond the division's normal main extension policies. This is the second year of the SGR program.

Regulated Pipeline Segment

Our regulated pipeline segment consists of the 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 to third parties customary in the pipeline industry including parking arrangements, lending arrangements and sales of excess gas.

Our regulated pipeline 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, 2014 compared with Three Months Ended December 31, 2013

Financial and operational highlights for our regulated pipeline segment for the three months ended December 31, 2014 and 2013 are presented below.

	Three Months Ended December 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 60,079	$ 49,744	$ 10,335
Third-party transportation	20,394	17,159	3,235
Storage and park and lend services	1,004	1,821	(817)
Other	2,090	2,617	(527)
Gross profit	83,567	71,341	12,226
Operating expenses	40,862	31,749	9,113
Operating income	42,705	39,592	3,113
Miscellaneous expense	(252)	(1,181)	929
Interest charges	8,324	8,957	(633)
Income before income taxes	34,129	29,454	4,675
Income tax expense	12,094	10,008	2,086
Net income	$ 22,035	$ 19,446	$ 2,589
Gross pipeline transportation volumes — MMcf	181,362	189,176	(7,814)
Consolidated pipeline transportation volumes — MMcf	120,634	118,774	1,860

Net income for our regulated pipeline segment increased 13 percent, primarily due to a $12.2 million increase in gross profit, partially offset by an $9.1 million increase in operating expenses. The increase in gross profit primarily reflects a $12.5 million increase in rates from the approved 2014 GRIP filing. Additionally, gross profit reflects increased pipeline demand fees and transportation rates that were offset by lower park and lend, storage and blending fees, and the absence of a $1.8 million increase recorded in the prior-year quarter associated with the renewal of an annual adjustment mechanism.

Operating expenses increased $9.1 million primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system and increased depreciation expense associated with increased capital investments.

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and, historically, have represented 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 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.
- The collection of accounts receivable from customers, which could affect the level of bad debt expense recognized by this segment and
- 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, 2014 compared with Three Months Ended December 31, 2013

Financial and operating highlights for our nonregulated segment for the three months ended December 31, 2014 and 2013 are presented below.

	Three Months Ended December 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 10,759	$ 12,463	$ (1,704)
Storage and transportation services	3,313	3,535	(222)
Other	(5,831)	(8,002)	2,171
Total realized margins	8,241	7,996	245
Unrealized margins	7,798	10,570	(2,772)
Gross profit	16,039	18,566	(2,527)
Operating expenses	9,116	10,311	(1,195)
Operating income	6,923	8,255	(1,332)
Miscellaneous income	300	324	(24)
Interest charges	226	637	(411)
Income before income taxes	6,997	7,942	(945)
Income tax expense	2,824	3,129	(305)
Net income	$ 4,173	$ 4,813	$ (640)
Gross nonregulated delivered gas sales volumes — MMcf	108,193	107,579	614
Consolidated nonregulated delivered gas sales volumes — MMcf	90,930	92,637	(1,707)
Net physical position (Bcf)	17.1	15.5	1.6

The $2.5 million quarter-over-quarter decrease in gross profit reflected a $0.2 million increase in realized margins, combined with a $2.8 million decrease in unrealized margins. The $0.2 million increase in realized margins primarily reflects:

- A $2.2 million increase in other realized margins, primarily due to a reduction in third-party storage fees and the timing and magnitude of settled financial positions quarter over quarter.
- A $1.7 million decrease in gas delivery and related services margins, largely due to a reduction in per unit margins from 12 cents per Mcf in the prior-year quarter to 10 cents, and a two percent decrease in consolidated sales volumes. Both per unit margins and consolidated sales volumes reflect the impact of warmer weather during the current quarter compared to the prior-year period. Additionally, increased transportation costs adversely impacted per-unit margins.

Unrealized margins decreased $2.8 million primarily due to the quarter-over-quarter timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses decreased $1.2 million, primarily due to lower employee-related 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. To support our capital market activities, we have a shelf registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. As of December 31, 2014, approximately $845 million of securities remained available for issuance under the shelf registration statement until March 28, 2016.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2014, September 30, 2014 and December 31, 2013:

	December 31, 2014		September 30, 2014		December 31, 2013	
	(In thousands, except percentages)					
Short-term debt	$ 550,903	9.1%	$ 196,695	3.4%	$ 689,795	11.9%
Long-term debt	2,455,131	40.4%	2,455,986	42.8%	2,455,750	42.3%
Shareholders' equity	3,063,925	50.5%	3,086,232	53.8%	2,661,314	45.8%
Total	$ 6,069,959	100.0%	$ 5,738,913	100.0%	$ 5,806,859	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 49.5 percent at December 31, 2014, 46.2 percent at September 30, 2014 and 54.2 percent at December 31, 2013.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, 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, 2014 and 2013 are presented below.

	Three Months Ended December 31		
	2014	2013	Change
	(In thousands)		
Total cash provided by (used in)			
Operating activities	$ 27,415	$ 34,300	$ (6,885)
Investing activities	(262,052)	(186,434)	(75,618)
Financing activities	316,211	280,498	35,713
Change in cash and cash equivalents	81,574	128,364	(46,790)
Cash and cash equivalents at beginning of period	42,258	66,199	(23,941)
Cash and cash equivalents at end of period	$ 123,832	$ 194,563	$ (70,731)

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 regulated distribution segment resulting from changes in 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, 2014, we generated cash flow of $27.4 million from operating activities compared with $34.3 million for the three months ended December 31, 2013. The $6.9 million decrease in operating cash flows primarily reflects the timing of customer collections and vendor payments.

Cash flows from investing activities

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, substantially all of our regulated 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.

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. Over the last two fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system. Our ongoing construction program enables us to enhance the safety and reliability of the systems used to provide regulated 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.

We anticipate our annual capital spending will be in the range of $900 million to $1.1 billion through fiscal 2018 as we continue to invest in the safety and reliability of our distribution and transportation system. Where possible, we will also continue to focus our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system.

For the three months ended December 31, 2014, capital expenditures were $261.3 million, compared with $180.6 million in the prior-year period. The $80.7 million increase primarily reflects:

- A $41.8 million increase in capital spending in our regulated pipeline segment primarily related to the enhancement and fortification of two storage fields to ensure the reliability of gas service to our Mid-Tex Division.
- A $38.7 million increase in capital spending in our regulated distribution segment, which primarily reflects the timing of the spending combined with a planned increase in safety and reliability investment in fiscal 2015.

Cash flows from financing activities

For the three months ended December 31, 2014, our financing activities generated $316.2 million of cash compared with $280.5 million generated in the prior-year period. The $35.7 million increase is primarily due to timing between short-term debt borrowings and repayments during the current year, proceeds from the issuance of $500 million unsecured 4.125% senior notes in October 2014 and the settlement of the associated forward starting interest rate swaps, partially offset by the repayment of $500 million 4.95% senior unsecured notes at maturity on October 15, 2014

The following table summarizes our share issuances for the three months ended December 31, 2014 and 2013.

	Three Months Ended December 31	
	2014	**2013**
Shares issued:		
Direct stock purchase plan	60,936	—
1998 Long-Term Incentive Plan	477,649	450,943
Retirement Savings Plan and Trust	75,580	—
Outside Directors Stock-for-Fee Plan	424	473
Total shares issued	614,589	451,416

The year-over-year increase in the number of shares issued primarily reflects the fact that we have begun issuing shares for the Direct Stock Purchase Plan and the Retirement Savings Plan rather than using shares purchased in the open market. For the three months ended December 31, 2014 and 2013, we canceled and retired 148,464 and 133,325 shares attributable to federal income tax 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 $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.3 billion of working capital funding. As of December 31, 2014, the amount available to us under our credit facilities, net of outstanding letters of credit, was $759.3 million.

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, 2014, S&P and Moody's maintained a stable outlook while Fitch maintained a positive outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Senior unsecured long-term debt	A-	A2	A-
Commercial paper	A-2	P-1	F-2

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2014. 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, 2014.

Risk Management Activities

We conduct risk management activities through our regulated distribution and nonregulated segments. In our regulated 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. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

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 regulated distribution segment's financial instruments for the three months ended December 31, 2014 and 2013:

	Three Months Ended December 31	
	2014	2013
	(In thousands)	
Fair value of contracts at beginning of period	$ 14,284	$ 109,648
Contracts realized/settled	(23,156)	(1,671)
Fair value of new contracts	(365)	519
Other changes in value	(85,611)	26,280
Fair value of contracts at end of period	$ (94,848)	$ 134,776

The fair value of our regulated distribution segment's financial instruments at December 31, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2014				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
			(In thousands)		
Prices actively quoted	$ (12,849)	$ (81,999)	$ —	$ —	$ (94,848)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (12,849)	$ (81,999)	$ —	$ —	$ (94,848)

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, 2014 and 2013:

	Three Months Ended December 31	
	2014	2013
	(In thousands)	
Fair value of contracts at beginning of period	$ (3,033)	$ (14,700)
Contracts realized/settled	7,165	9,943
Fair value of new contracts	—	—
Other changes in value	(30,231)	(336)
Fair value of contracts at end of period	(26,099)	(5,093)
Netting of cash collateral	43,501	16,708
Cash collateral and fair value of contracts at period end	$ 17,402	$ 11,615

The fair value of our nonregulated segment's financial instruments at December 31, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at December 31, 2014				
	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	$ (20,363)	$ (6,128)	$ 392	$ —	$ (26,099)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (20,363)	$ (6,128)	$ 392	$ —	$ (26,099)

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2014 and 2013, our total net periodic pension and other benefits costs were $14.7 million and $20.9 million. A substantial portion of those costs relating to our regulated 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 2015 costs were determined using a September 30, 2014 measurement date. As of September 30, 2014, interest and corporate bond rates utilized to determine our discount rates were lower than the interest and corporate bond rates as of September 30, 2013, the measurement date for our fiscal 2014 net periodic cost. Therefore, we decreased the discount rate used to measure our fiscal 2015 net periodic cost from 4.95 percent to 4.43 percent. We maintained our expected return on plan assets at 7.25 percent in the determination of our fiscal 2015 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes of these and other assumptions and the absence of a $4.5 million non-recurring settlement loss recorded during the first quarter of fiscal 2014, we expect our fiscal 2015 net periodic pension cost to decrease by approximately 10 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. Based upon current market conditions, the current funded position of the plans and the funding requirements under the PPA, we do not anticipate a minimum required contribution for fiscal 2015. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels. For the three months ended December 31, 2014 we contributed $5.6 million to our postretirement medical plans. We anticipate contributing a total of between $20 million and $25 million to these plans during fiscal 2015.

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.

In October 2014, the Society of Actuaries released its final report on mortality tables and the mortality improvement scale to reflect increasing life expectancies in the United States. We anticipate utilizing the new mortality data in our next actuarial calculation date on September 30, 2015. We are currently evaluating the impact the updated data will have on the valuation of our defined benefit and other post-retirement benefits plans. It is expected the use of this new data will increase the total amount of liabilities reported on our balance sheet in future periods by less than five percent.

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our regulated distribution, regulated pipeline and nonregulated segments for the three month periods ended December 31, 2014 and 2013.

Regulated Distribution Sales and Statistical Data

	Three Months Ended December 31			
		2014		2013
METERS IN SERVICE, end of period				
Residential		2,862,369		2,782,064
Commercial		261,593		249,348
Industrial		1,538		1,508
Public authority and other		8,451		10,011
Total meters		3,133,951		3,042,931
INVENTORY STORAGE BALANCE — Bcf		53.0		52.5
SALES VOLUMES — MMcf[1]				
Gas sales volumes				
Residential		52,218		60,416
Commercial		28,715		31,414
Industrial		3,890		4,019
Public authority and other		2,099		2,429
Total gas sales volumes		86,922		98,278
Transportation volumes		38,835		35,424
Total throughput		125,757		133,702
OPERATING REVENUES (000's)[1]				
Gas sales revenues				
Residential	$	541,725	$	545,417
Commercial		241,630		235,423
Industrial		22,911		23,748
Public authority and other		14,998		16,449
Total gas sales revenues		821,264		821,037
Transportation revenues		19,152		16,817
Other gas revenues		6,356		6,011
Total operating revenues	$	846,772	$	843,865
Average transportation revenue per Mcf	$	0.49	$	0.47
Average cost of gas per Mcf sold	$	6.02	$	5.54

See footnote following these tables.

Regulated Pipeline and Nonregulated Operations Sales and Statistical Data

	Three Months Ended December 31	
	2014	**2013**
CUSTOMERS, end of period		
Industrial	747	758
Municipal	129	126
Other	539	546
Total	1,415	1,430
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	21.6	21.1
REGULATED PIPELINE VOLUMES — MMcf[1]	181,362	189,176
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[1]	108,193	107,579
OPERATING REVENUES (000's)[1]		
Regulated pipeline	$ 83,567	$ 71,341
Nonregulated	462,288	436,431
Total operating revenues	$ 545,855	$ 507,772

Note to preceding tables:

(1) 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, 2014. During the three months ended December 31, 2014, 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, 2014 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, 2015 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, 2014, 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, 2014. 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 3, 2015

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.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

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 ☑ 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 ☑ 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 ☑ 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 ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of August 1, 2014.

Class	Shares Outstanding
No Par Value	100,351,676

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
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

	June 30, 2014	September 30, 2013
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 8,217,954	$ 7,722,019
Less accumulated depreciation and amortization	1,756,504	1,691,364
Net property, plant and equipment	6,461,450	6,030,655
Current assets		
Cash and cash equivalents	51,421	66,199
Accounts receivable, net	388,874	301,992
Gas stored underground	207,458	244,741
Other current assets	126,890	64,201
Total current assets	774,643	677,133
Goodwill	741,363	741,363
Deferred charges and other assets	379,733	485,117
	$ 8,357,189	$ 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: June 30, 2014 — 100,346,468 shares; September 30, 2013 — 90,640,211 shares	$ 502	$ 453
Additional paid-in capital	2,172,307	1,765,811
Retained earnings	932,576	775,267
Accumulated other comprehensive income	11,300	38,878
Shareholders' equity	3,116,685	2,580,409
Long-term debt	1,955,907	2,455,671
Total capitalization	5,072,592	5,036,080
Current liabilities		
Accounts payable and accrued liabilities	312,671	241,611
Other current liabilities	343,026	368,891
Short-term debt	—	367,984
Current maturities of long-term debt	500,000	—
Total current liabilities	1,155,697	978,486
Deferred income taxes	1,341,294	1,164,053
Regulatory cost of removal obligation	391,785	359,299
Pension and postretirement liabilities	347,344	358,787
Deferred credits and other liabilities	48,477	37,563
	$ 8,357,189	$ 7,934,268

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2014	2013
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 517,707	$ 467,144
Regulated transmission and storage segment	87,189	74,041
Nonregulated segment	465,033	421,808
Intersegment eliminations	(127,211)	(105,058)
	942,718	857,935
Purchased gas cost		
Natural gas distribution segment	260,042	227,649
Regulated transmission and storage segment	—	—
Nonregulated segment	450,220	418,548
Intersegment eliminations	(127,077)	(104,759)
	583,185	541,438
Gross profit	359,533	316,497
Operating expenses		
Operation and maintenance	125,559	121,258
Depreciation and amortization	63,955	58,129
Taxes, other than income	63,414	50,714
Total operating expenses	252,928	230,101
Operating income	106,605	86,396
Miscellaneous expense	(374)	(467)
Interest charges	31,840	32,741
Income from continuing operations before income taxes	74,391	53,188
Income tax expense	28,670	19,714
Income from continuing operations	45,721	33,474
Gain on sale of discontinued operations, net of tax ($0 and $2,909)	—	5,294
Net income	$ 45,721	$ 38,768
Basic earnings per share		
Income per share from continuing operations	$ 0.45	$ 0.37
Income per share from discontinued operations	—	0.06
Net income per share — basic	$ 0.45	$ 0.43
Diluted earnings per share		
Income per share from continuing operations	$ 0.45	$ 0.36
Income per share from discontinued operations	—	0.06
Net income per share — diluted	$ 0.45	$ 0.42
Cash dividends per share	$ 0.37	$ 0.35
Weighted average shares outstanding:		
Basic	100,267	90,603
Diluted	101,150	91,550

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2014	2013
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 2,652,532	$ 2,039,107
Regulated transmission and storage segment	232,145	196,570
Nonregulated segment	1,670,437	1,250,650
Intersegment eliminations	(392,926)	(285,241)
	4,162,188	3,201,086
Purchased gas cost		
Natural gas distribution segment	1,710,508	1,172,975
Regulated transmission and storage segment	—	—
Nonregulated segment	1,599,469	1,200,624
Intersegment eliminations	(392,556)	(284,123)
	2,917,421	2,089,476
Gross profit	1,244,767	1,111,610
Operating expenses		
Operation and maintenance	365,991	338,871
Depreciation and amortization	185,731	174,888
Taxes, other than income	165,640	146,355
Total operating expenses	717,362	660,114
Operating income	527,405	451,496
Miscellaneous income (expense)	(4,022)	1,943
Interest charges	95,556	96,594
Income from continuing operations before income taxes	427,827	356,845
Income tax expense	161,723	133,683
Income from continuing operations	266,104	223,162
Income from discontinued operations, net of tax ($0 and $3,986)	—	7,202
Gain on sale of discontinued operations, net of tax ($0 and $2,909)	—	5,294
Net income	$ 266,104	$ 235,658
Basic earnings per share		
Income per share from continuing operations	$ 2.78	$ 2.46
Income per share from discontinued operations	—	0.14
Net income per share — basic	$ 2.78	$ 2.60
Diluted earnings per share		
Income per share from continuing operations	$ 2.76	$ 2.43
Income per share from discontinued operations	—	0.14
Net income per share — diluted	$ 2.76	$ 2.57
Cash dividends per share	$ 1.11	$ 1.05
Weighted average shares outstanding:		
Basic	95,455	90,497
Diluted	96,339	91,445

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
	(Unaudited) (In thousands)			
Net income	$ 45,721	$ 38,768	$ 266,104	$ 235,658
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $216, $(202), $1,518 and $(532)	377	(348)	2,519	(921)
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(13,472), $17,865, $(21,005) and $38,427	(23,440)	31,079	(36,545)	66,852
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $(1,580), $(2,243), $4,122 and $3,174	(2,471)	(3,508)	6,448	4,965
Total other comprehensive income (loss)	(25,534)	27,223	(27,578)	70,896
Total comprehensive income	$ 20,187	$ 65,991	$ 238,526	$ 306,554

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2014	2013
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 266,104	$ 235,658
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of discontinued operations	—	(8,203)
Depreciation and amortization:		
Charged to depreciation and amortization	185,731	176,737
Charged to other accounts	669	446
Deferred income taxes	150,457	130,365
Other	21,587	14,460
Net assets / liabilities from risk management activities	3,158	(6,386)
Net change in operating assets and liabilities	2,504	(33,502)
Net cash provided by operating activities	630,210	509,575
Cash Flows From Investing Activities		
Capital expenditures	(552,600)	(582,473)
Proceeds from the sale of discontinued operations	—	153,023
Other, net	(620)	(3,139)
Net cash used in investing activities	(553,220)	(432,589)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(366,602)	(435,084)
Net proceeds from equity offering	390,205	—
Net proceeds from issuance of long-term debt	—	493,793
Settlement of Treasury lock agreements	—	(66,626)
Repayment of long-term debt	—	(131)
Cash dividends paid	(108,806)	(96,060)
Repurchase of equity awards	(8,717)	(5,146)
Issuance of common stock	2,152	8
Net cash used in financing activities	(91,768)	(109,246)
Net decrease in cash and cash equivalents	(14,778)	(32,260)
Cash and cash equivalents at beginning of period	66,199	64,239
Cash and cash equivalents at end of period	$ 51,421	$ 31,979

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2014

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 June 30, 2014, 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 North Texas 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.

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 nine-month period ended June 30, 2014 are not indicative of our results of operations for the full 2014 fiscal year, which ends September 30, 2014.

Except for the forward starting interest rate swap entered into in July 2014 as noted in Note 8, 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.

During the second quarter of fiscal 2014, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

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.

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. In connection with the adoption of this standard, prior-year risk management assets and liabilities have been reclassified to conform with the current-year presentation. The adoption of this standard and reclassification did not have an impact on our financial position, results of operations or cash flows.

In April 2014, the Financial Accounting Standards Board (FASB) issued updated guidance for discontinued operations that limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have a major effect on an entity's operations and financial results and requires additional disclosures related to discontinued operations. This standard will become effective for us beginning on October 1, 2015. The adoption of this guidance is not expected to impact our financial position, results of operations or cash flows.

In May 2014, the FASB issued a comprehensive new revenue recognition standard that will supersede virtually all existing revenue recognition guidance under generally accepted accounting principles in the United States. Under the new standard, a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under current guidance. The new standard will become effective for us beginning on October 1, 2017 and can be applied either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

There were no other significant changes to our accounting policies during the nine months ended June 30, 2014 that will become applicable to the Company in future periods.

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 June 30, 2014 and September 30, 2013 included the following:

	June 30, 2014	September 30, 2013
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$ 172,844	$ 187,977
Merger and integration costs, net	4,860	5,250
Deferred gas costs	9,809	15,152
Regulatory cost of removal asset	9,552	10,008
Rate case costs	4,436	6,329
Texas Rule 8.209[2]	19,349	30,364
APT annual adjustment mechanism	5,927	5,853
Recoverable loss on reacquired debt	19,517	21,435
Other	4,006	4,380
	$ 250,300	$ 286,748
Regulatory liabilities:		
Deferred gas costs	$ 62,522	$ 16,481
Deferred franchise fees	5,918	1,689
Regulatory cost of removal obligation	441,643	427,524
Other	11,509	7,887
	$ 521,592	$ 453,581

(1) Includes $18.0 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

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 and nine month periods ended June 30, 2014 and 2013 by segment are presented in the following tables:

	Three Months Ended June 30, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 516,644	$ 24,990	$ 401,084	$ —	$ 942,718
Intersegment revenues	1,063	62,199	63,949	(127,211)	—
	517,707	87,189	465,033	(127,211)	942,718
Purchased gas cost	260,042	—	450,220	(127,077)	583,185
Gross profit	257,665	87,189	14,813	(134)	359,533
Operating expenses					
Operation and maintenance	92,994	23,570	9,129	(134)	125,559
Depreciation and amortization	52,542	10,281	1,132	—	63,955
Taxes, other than income	57,596	5,054	764	—	63,414
Total operating expenses	203,132	38,905	11,025	(134)	252,928
Operating income	54,533	48,284	3,788	—	106,605
Miscellaneous income (expense)	678	(489)	1,018	(1,581)	(374)
Interest charges	23,649	9,162	610	(1,581)	31,840
Income before income taxes	31,562	38,633	4,196	—	74,391
Income tax expense	13,033	13,695	1,942	—	28,670
Net income	$ 18,529	$ 24,938	$ 2,254	$ —	$ 45,721
Capital expenditures	$ 146,860	$ 45,658	$ 1,073	$ —	$ 193,591

	Three Months Ended June 30, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 465,982	$ 26,730	$ 365,223	$ —	$ 857,935
Intersegment revenues	1,162	47,311	56,585	(105,058)	—
	467,144	74,041	421,808	(105,058)	857,935
Purchased gas cost	227,649	—	418,548	(104,759)	541,438
Gross profit	239,495	74,041	3,260	(299)	316,497
Operating expenses					
Operation and maintenance	93,490	17,035	11,034	(301)	121,258
Depreciation and amortization	48,368	8,676	1,085	—	58,129
Taxes, other than income	45,686	4,287	741	—	50,714
Total operating expenses	187,544	29,998	12,860	(301)	230,101
Operating income (loss)	51,951	44,043	(9,600)	2	86,396
Miscellaneous income (expense)	268	(247)	215	(703)	(467)
Interest charges	25,001	8,049	392	(701)	32,741
Income (loss) from continuing operations before income taxes	27,218	35,747	(9,777)	—	53,188
Income tax expense (benefit)	11,401	12,650	(4,337)	—	19,714
Income (loss) from continuing operations	15,817	23,097	(5,440)	—	33,474
Gain (loss) on sale of discontinued operations, net of tax	5,649	—	(355)	—	5,294
Net income (loss)	$ 21,466	$ 23,097	$ (5,795)	$ —	$ 38,768
Capital expenditures	$ 114,606	$ 78,012	$ 738	$ —	$ 193,356

	Nine Months Ended June 30, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,648,505	$ 67,162	$ 1,446,521	$ —	$ 4,162,188
Intersegment revenues	4,027	164,983	223,916	(392,926)	—
	2,652,532	232,145	1,670,437	(392,926)	4,162,188
Purchased gas cost	1,710,508	—	1,599,469	(392,556)	2,917,421
Gross profit	942,024	232,145	70,968	(370)	1,244,767
Operating expenses					
Operation and maintenance	289,433	57,465	19,463	(370)	365,991
Depreciation and amortization	152,113	30,223	3,395	—	185,731
Taxes, other than income	155,286	8,485	1,869	—	165,640
Total operating expenses	596,832	96,173	24,727	(370)	717,362
Operating income	345,192	135,972	46,241	—	527,405
Miscellaneous income (expense)	304	(2,751)	1,785	(3,360)	(4,022)
Interest charges	69,802	27,274	1,840	(3,360)	95,556
Income from before income taxes	275,694	105,947	46,186	—	427,827
Income tax expense	105,665	37,454	18,604	—	161,723
Net income	$ 170,029	$ 68,493	$ 27,582	$ —	$ 266,104
Capital expenditures	$ 413,921	$ 137,579	$ 1,100	$ —	$ 552,600

	Nine Months Ended June 30, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,035,712	$ 65,084	$ 1,100,290	$ —	$ 3,201,086
Intersegment revenues	3,395	131,486	150,360	(285,241)	—
	2,039,107	196,570	1,250,650	(285,241)	3,201,086
Purchased gas cost	1,172,975	—	1,200,624	(284,123)	2,089,476
Gross profit	866,132	196,570	50,026	(1,118)	1,111,610
Operating expenses					
Operation and maintenance	266,570	48,745	24,679	(1,123)	338,871
Depreciation and amortization	146,059	25,756	3,073	—	174,888
Taxes, other than income	132,029	12,513	1,813	—	146,355
Total operating expenses	544,658	87,014	29,565	(1,123)	660,114
Operating income	321,474	109,556	20,461	5	451,496
Miscellaneous income (expense)	2,728	(473)	1,791	(2,103)	1,943
Interest charges	74,228	22,777	1,687	(2,098)	96,594
Income from continuing operations before income taxes	249,974	86,306	20,565	—	356,845
Income tax expense	94,874	30,574	8,235	—	133,683
Income from continuing operations	155,100	55,732	12,330	—	223,162
Income from discontinued operations, net of tax	7,202	—	—	—	7,202
Gain (loss) on sale of discontinued operations, net of tax	5,649	—	(355)	—	5,294
Net income	$ 167,951	$ 55,732	$ 11,975	$ —	$ 235,658
Capital expenditures	$ 391,942	$ 189,051	$ 1,480	$ —	$ 582,473

Balance sheet information at June 30, 2014 and September 30, 2013 by segment is presented in the following tables:

	June 30, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,036,007	$ 1,366,928	$ 58,515	$ —	$ 6,461,450
Investment in subsidiaries	933,660	—	(2,096)	(931,564)	—
Current assets					
Cash and cash equivalents	17,042	—	34,379	—	51,421
Assets from risk management activities	36,438	—	7,918	—	44,356
Other current assets	461,644	15,813	581,221	(379,812)	678,866
Intercompany receivables	775,175	—	—	(775,175)	—
Total current assets	1,290,299	15,813	623,518	(1,154,987)	774,643
Goodwill	574,190	132,462	34,711	—	741,363
Noncurrent assets from risk management activities	20,708	—	5,109	—	25,817
Deferred charges and other assets	325,035	22,474	6,407	—	353,916
	$ 8,179,899	$ 1,537,677	$ 726,164	$ (2,086,551)	$ 8,357,189
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,116,685	$ 464,914	$ 468,746	$ (933,660)	$ 3,116,685
Long-term debt	1,955,907	—	—	—	1,955,907
Total capitalization	5,072,592	464,914	468,746	(933,660)	5,072,592
Current liabilities					
Current maturities of long-term debt	500,000	—	—	—	500,000
Short-term debt	357,000	—	—	(357,000)	—
Liabilities from risk management activities	609	—	—	—	609
Other current liabilities	477,726	14,837	183,241	(20,716)	655,088
Intercompany payables	—	717,134	58,041	(775,175)	—
Total current liabilities	1,335,335	731,971	241,282	(1,152,891)	1,155,697
Deferred income taxes	988,737	338,350	14,207	—	1,341,294
Noncurrent liabilities from risk management activities	7,024	—	—	—	7,024
Regulatory cost of removal obligation	391,785	—	—	—	391,785
Pension and postretirement liabilities	347,344	—	—	—	347,344
Deferred credits and other liabilities	37,082	2,442	1,929	—	41,453
	$ 8,179,899	$ 1,537,677	$ 726,164	$ (2,086,551)	$ 8,357,189

	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
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	8,849	—	375,763
	$ 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 and nine months ended June 30, 2014 and 2013 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Basic Earnings Per Share from continuing operations				
Income from continuing operations	$ 45,721	$ 33,474	$ 266,104	$ 223,162
Less: Income from continuing operations allocated to participating securities	107	91	674	760
Income from continuing operations available to common shareholders	$ 45,614	$ 33,383	$ 265,430	$ 222,402
Basic weighted average shares outstanding	100,267	90,603	95,455	90,497
Income from continuing operations per share — Basic	$ 0.45	$ 0.37	$ 2.78	$ 2.46
Basic Earnings Per Share from discontinued operations				
Income from discontinued operations	$ —	$ 5,294	$ —	$ 12,496
Less: Income from discontinued operations allocated to participating securities	—	14	—	43
Income from discontinued operations available to common shareholders	$ —	$ 5,280	$ —	$ 12,453
Basic weighted average shares outstanding	100,267	90,603	95,455	90,497
Income from discontinued operations per share — Basic	$ —	$ 0.06	$ —	$ 0.14
Net income per share — Basic	$ 0.45	$ 0.43	$ 2.78	$ 2.60

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Diluted Earnings Per Share from continuing operations				
Income from continuing operations available to common shareholders	$ 45,614	$ 33,383	$ 265,430	$ 222,402
Effect of dilutive stock options and other shares	—	—	4	5
Income from continuing operations available to common shareholders	$ 45,614	$ 33,383	$ 265,434	$ 222,407
Basic weighted average shares outstanding	100,267	90,603	95,455	90,497
Additional dilutive stock options and other shares	883	947	884	948
Diluted weighted average shares outstanding	101,150	91,550	96,339	91,445
Income from continuing operations per share — Diluted	$ 0.45	$ 0.36	$ 2.76	$ 2.43
Diluted Earnings Per Share from discontinued operations				
Income from discontinued operations available to common shareholders	$ —	$ 5,280	$ —	$ 12,453
Effect of dilutive stock options and other shares	—	—	—	—
Income from discontinued operations available to common shareholders	$ —	$ 5,280	$ —	$ 12,453
Basic weighted average shares outstanding	100,267	90,603	95,455	90,497
Additional dilutive stock options and other shares	883	947	884	948
Diluted weighted average shares outstanding	101,150	91,550	96,339	91,445
Income from discontinued operations per share — Diluted	$ —	$ 0.06	$ —	$ 0.14
Net income per share — Diluted	$ 0.45	$ 0.42	$ 2.76	$ 2.57

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2014 and 2013 as their exercise price was less than the average market price of the common stock during those periods.

2014 Equity Offering

On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares under our existing shelf registration statement. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

2011 Share Repurchase Program

We did not repurchase any shares during the nine months ended June 30, 2014 and 2013 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 nine months ended June 30, 2014.

Long-term debt

Long-term debt at June 30, 2014 and September 30, 2013 consisted of the following:

	June 30, 2014	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	4,093	4,329
Current maturities	500,000	—
	$ 1,955,907	$ 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 billion of working capital funding. At June 30, 2014, there were no short-term debt borrowings outstanding. At September 30, 2013, there was a total of $368.0 million 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 increase 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 June 30, 2014.

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. In December 2013, the $25 million 364-day uncommitted bilateral facility was extended to December 2014. In January 2014, this facility was amended to temporarily increase the amount available to $50 million to address the increase in volumes and prices driven by colder than normal weather this past winter-heating season. In June 2014, the facility was further amended to extend the temporary increase for 90 days through September 28, 2014. The maximum available under the facility will return to $25 million after the additional 90-day period expires. The $25 million committed bilateral facility was replaced with a $15 million committed 364-day bilateral credit facility in December 2013. 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 $52.3 million at 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 filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013 that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock, which generated net proceeds of $390.2 million. As of June 30, 2014, $1.35 billion of securities remained available for issuance under the shelf registration statement until March 28, 2016.

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 June 30, 2014, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 46 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 June 30, 2014. 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 and nine months ended June 30, 2014 and 2013 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 executive officers, we recognized a settlement loss of $4.5 million associated with our Supplemental Executive Benefits Plan (SEBP). In association with his retirement, on October 2, 2013, we made a $16.8 million benefit payment from the SEBP. On April 1, 2013, due to the retirement of certain executives, we recognized a curtailment loss of $3.2 million associated with our SEBP and revalued the net periodic pension cost for the remainder of fiscal 2013. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective April 1, 2013, to 4.21 percent, which reduced our net periodic pension cost by approximately $0.1 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,738	$ 5,194	$ 4,196	$ 4,700
Interest cost	6,824	6,019	3,987	3,241
Expected return on assets	(5,901)	(5,739)	(1,291)	(997)
Amortization of transition obligation	—	—	69	271
Amortization of prior service credit	(34)	(35)	(363)	(363)
Amortization of actuarial loss	3,931	5,432	158	1,049
Settlement loss	—	3,161	—	—
Net periodic pension cost	$ 9,558	$ 14,032	$ 6,756	$ 7,901

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 14,214	$ 15,599	$ 12,588	$ 14,100
Interest cost	20,472	18,067	11,963	9,723
Expected return on assets	(17,702)	(17,216)	(3,875)	(2,991)
Amortization of transition obligation	—	—	205	811
Amortization of prior service credit	(102)	(106)	(1,088)	(1,088)
Amortization of actuarial loss	11,793	16,555	474	3,147
Settlement loss	4,539	3,161	—	—
Net periodic pension cost	$ 33,214	$ 36,060	$ 20,267	$ 23,702

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2014 and 2013 are as follows:

	Supplemental Executive Benefit Plans		Pension Benefits		Other Benefits	
	2014	2013	2014	2013	2014	2013
Discount rate	4.95%	4.21%	4.95%	4.04%	4.95%	4.04%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	N/A	N/A
Expected return on plan assets	N/A	N/A	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 nine months of fiscal 2014, we contributed $27.1 million to our defined benefit plans and we do not anticipate making any contributions during the fourth quarter of fiscal 2014.

We contributed $18.1 million to our other post-retirement benefit plans during the nine months ended June 30, 2014. We expect to contribute a total of approximately $20 million to $25 million to these plans during all of fiscal 2014.

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 nine months ended June 30, 2014.

Kentucky Litigation

Beginning in April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), were 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 plus accrued interest to one landowner on that claim. The claim was paid on February 18, 2013. 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, then each filed with the Supreme Court of Kentucky, separate motions for discretionary review of the opinion of the Court of Appeals. We filed responses to the motions. The Kentucky Supreme Court denied the motions for discretionary review on February 12, 2014 and the decision of the Court of Appeals became final on February 21, 2014. We had previously accrued what we believed to be an adequate amount for the anticipated resolution of this matter. This accrual was reversed during the second fiscal quarter of fiscal 2014 as the appellate process in this case had been completed. Atmos Energy had also filed a motion with the trial court, the Circuit Court of Edmonson County, Kentucky, on March 10, 2014, seeking a ruling that the remaining landowner was not entitled to any punitive damages on the sole remaining claim of trespass. On May 19, 2014, the Edmonson County Circuit Court entered judgment dismissing any claim for punitive damages relating to the trespass claim. There was no appeal of this judgment. The lawsuit in Edmonson County has now been fully and finally resolved.

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 AGC 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. Atmos Energy filed a motion for partial summary judgment against the defendants with the District Court on July 15, 2014, with a ruling by the Court still pending. This case is scheduled for trial beginning October 6, 2014.

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. The cumulative assessment approximated $12 million as of March 31, 2014, which AEM challenged. We had previously accrued in prior years what we believed to be an adequate amount for the anticipated resolution of this matter. 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. An agreed order of dismissal with prejudice between AEM and TDOR was approved by the Chancery Court and entered on May 2, 2014, whereby AEM agreed to pay $6.2 million to TDOR to resolve all business tax-related liabilities outstanding through September 2014. The State of Tennessee also passed related legislation, effective July 1, 2014, that should help minimize any disputes over this type of sales business tax in the future.

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 June 30, 2014, AEH was committed to purchase 105.2 Bcf within one year, 18.0 Bcf within one to three years and 0.6 Bcf after three years under indexed contracts. AEH is committed to purchase 10.0 Bcf within one year under fixed price contracts with prices ranging from $3.66 to $6.36 per Mcf. Purchases under these contracts totaled $383.2 million and $340.9 million for the three months ended June 30, 2014 and 2013 and $1,354.5 million and $958.2 million for the nine months ended June 30, 2014 and 2013.

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

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of June 30, 2014 are as follows (in thousands):

2014	$ 51,946
2015	234,824
2016	167,747
2017	67,185
Thereafter	—
	$ 521,702

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 nine months ended June 30, 2014.

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 June 30, 2014, rate cases were in progress in our Kansas, Colorado and Virginia service areas, annual rate filing mechanisms were in progress in Louisiana and Mid-Tex and an infrastructure program filing was in progress in Virginia. 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 nine months ended June 30, 2014 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 hedged approximately 32 percent, or 24.6 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

The costs associated with 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 46 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 effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

As of June 30, 2014, we had forward starting interest rate swaps to effectively 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, at 3.129% and 3.37%, which we designated as cash flow hedges at the time the agreements were executed. In April, May and July 2014, we entered into forward starting interest rate swaps to effectively fix the Treasury yield component associated with $325 million of the anticipated issuance of $450 million unsecured senior notes in fiscal 2019 at 3.91%, 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 June 30, 2014, the remaining amortization periods for the settled Treasury locks extended 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 June 30, 2014, 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 June 30, 2014, 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	—	(9,255)
	Cash Flow	—	29,930
	Not designated	20,826	63,168
		20,826	83,843

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 June 30, 2014 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)			
June 30, 2014					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 8,442	$ (3,741)
Interest rate contracts	Other current assets / Other current liabilities	33,183	—	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	730	(1,421)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	20,455	(6,849)	—	—
Total		53,638	(6,849)	9,172	(5,162)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	3,255	(609)	45,242	(51,715)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	253	(175)	20,476	(14,675)
Total		3,508	(784)	65,718	(66,390)
Gross Financial Instruments		57,146	(7,633)	74,890	(71,552)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(69,782)	69,782
Net Financial Instruments		57,146	(7,633)	5,108	(1,770)
Cash collateral		—	—	7,919	1,770
Net Assets/Liabilities from Risk Management Activities		$ 57,146	$ (7,633)	$ 13,027	$ —

	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 June 30, 2014 and 2013 we recognized a loss arising from fair value and cash flow hedge ineffectiveness of $0.1 million and $0.4 million. For the nine months ended June 30, 2014 and 2013, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $1.3 million and $17.3 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 and nine months ended June 30, 2014 and 2013 is presented below.

	Three Months Ended June 30 2014	Three Months Ended June 30 2013
	(In thousands)	
Commodity contracts	$ 1,991	$ 14,453
Fair value adjustment for natural gas inventory designated as the hedged item	(2,258)	(15,143)
Total increase in purchased gas cost	$ (267)	$ (690)
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ 817	$ (2,361)
Timing ineffectiveness	(1,084)	1,671
	$ (267)	$ (690)

	Nine Months Ended June 30 2014	2013
	(In thousands)	
Commodity contracts	$ (2,983)	$ 3,921
Fair value adjustment for natural gas inventory designated as the hedged item	4,071	13,261
Total decrease in purchased gas cost	$ 1,088	$ 17,182
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (382)	$ (1,143)
Timing ineffectiveness	1,470	18,325
	$ 1,088	$ 17,182

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 and nine months ended June 30, 2014 and 2013 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 June 30, 2014 Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 4,209	$ 4,209
Gain arising from ineffective portion of commodity contracts	—	179	179
Total impact on purchased gas cost	—	4,388	4,388
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,057)	—	(1,057)
Total Impact from Cash Flow Hedges	$ (1,057)	$ 4,388	$ 3,331

	Three Months Ended June 30, 2013 Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 558	$ 558
Gain arising from ineffective portion of commodity contracts	—	260	260
Total impact on purchased gas cost	—	818	818
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,057)	—	(1,057)
Total Impact from Cash Flow Hedges	$ (1,057)	$ 818	$ (239)

	Nine Months Ended June 30, 2014		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 8,783	$ 8,783
Gain arising from ineffective portion of commodity contracts	—	203	203
Total impact on purchased gas cost	—	8,986	8,986
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(3,172)	—	(3,172)
Total Impact from Cash Flow Hedges	$ (3,172)	$ 8,986	$ 5,814

	Nine Months Ended June 30, 2013		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (9,802)	$ (9,802)
Gain arising from ineffective portion of commodity contracts	—	158	158
Total impact on purchased gas cost	—	(9,644)	(9,644)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(2,432)	—	(2,432)
Total Impact from Cash Flow Hedges	$ (2,432)	$ (9,644)	$ (12,076)

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 and nine months ended June 30, 2014 and 2013. 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 June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
		(In thousands)		
Increase (decrease) in fair value:				
Interest rate agreements	$ (24,111)	$ 30,408	$ (38,559)	$ 65,308
Forward commodity contracts	96	(3,168)	11,805	(1,015)
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	671	671	2,014	1,544
Forward commodity contracts	(2,567)	(340)	(5,357)	5,980
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ (25,911)	$ 27,571	$ (30,097)	$ 71,817

(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 June 30, 2014. 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	$ (1,317)	$ 2,407	$ 1,090
Thereafter	(27,033)	(435)	(27,468)
Total[1]	$ (28,350)	$ 1,972	$ (26,378)

(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 June 30, 2014 and 2013 was a decrease in gross profit of $0.6 million and $8.4 million. For the nine months ended June 30, 2014 and 2013 gross profit decreased by $10.7 million and $1.7 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 (loss) before reclassifications	3,212	(38,559)	11,805	(23,542)
Amounts reclassified from accumulated other comprehensive income	(693)	2,014	(5,357)	(4,036)
Net current-period other comprehensive income (loss)	2,519	(36,545)	6,448	(27,578)
June 30, 2014	$ 7,967	$ 1,361	$ 1,972	$ 11,300

	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 (loss) before reclassifications	449	65,308	(1,015)	64,742
Amounts reclassified from accumulated other comprehensive income	(1,370)	1,544	5,980	6,154
Net current-period other comprehensive income (loss)	(921)	66,852	4,965	70,896
June 30, 2013	$ 4,740	$ 22,579	$ (4,030)	$ 23,289

The following tables detail reclassifications out of AOCI for the three and nine months ended June 30, 2014 and 2013. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended June 30, 2014	
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**	**Affected Line Item in the Statement of Income**
	(In thousands)	
Available-for-sale securities	$ 733	Operation and maintenance expense
	733	Total before tax
	(267)	Tax expense
	$ 466	Net of tax
Cash flow hedges		
Interest rate agreements	$ (1,057)	Interest charges
Commodity contracts	4,209	Purchased gas cost
	3,152	Total before tax
	(1,256)	Tax expense
	$ 1,896	Net of tax
Total reclassifications	$ 2,362	Net of tax

	Three Months Ended June 30, 2013	
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**	**Affected Line Item in the Statement of Income**
	(In thousands)	
Available-for-sale securities	$ (531)	Operation and maintenance expense
	(531)	Total before tax
	193	Tax benefit
	$ (338)	Net of tax
Cash flow hedges		
Interest rate agreements	$ (1,057)	Interest charges
Commodity contracts	558	Purchased gas cost
	(499)	Total before tax
	168	Tax benefit
	$ (331)	Net of tax
Total reclassifications	$ (669)	Net of tax

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2014 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Nine Months Ended June 30, 2014 Affected Line Item in the Statement of Income
Available-for-sale securities	$ 1,091	Operation and maintenance expense
	1,091	Total before tax
	(398)	Tax expense
	$ 693	Net of tax
Cash flow hedges		
Interest rate agreements	$ (3,172)	Interest charges
Commodity contracts	8,783	Purchased gas cost
	5,611	Total before tax
	(2,268)	Tax expense
	$ 3,343	Net of tax
Total reclassifications	$ 4,036	Net of tax

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2013 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Nine Months Ended June 30, 2013 Affected Line Item in the Statement of Income
Available-for-sale securities	$ 2,158	Operation and maintenance expense
	2,158	Total before tax
	(788)	Tax expense
	$ 1,370	Net of tax
Cash flow hedges		
Interest rate agreements	$ (2,432)	Interest charges
Commodity contracts	(9,803)	Purchased gas cost
	(12,235)	Total before tax
	4,711	Tax benefit
	$ (7,524)	Net of tax
Total reclassifications	$ (6,154)	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 nine months ended June 30, 2014, 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 is 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 June 30, 2014 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)	June 30, 2014
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 57,146	$ —	$ —	$ 57,146
Nonregulated segment	3	74,887	—	(61,863)	13,027
Total financial instruments	3	132,033	—	(61,863)	70,173
Hedged portion of gas stored underground	39,191	—	—	—	39,191
Available-for-sale securities					
Money market funds	—	1,959	—	—	1,959
Registered investment companies	45,554	—	—	—	45,554
Bonds	—	33,397	—	—	33,397
Total available-for-sale securities	45,554	35,356	—	—	80,910
Total assets	$ 84,748	$ 167,389	$ —	$ (61,863)	$ 190,274
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 7,633	$ —	$ —	$ 7,633
Nonregulated segment	108	71,444	—	(71,552)	—
Total liabilities	$ 108	$ 79,077	$ —	$ (71,552)	$ 7,633

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2013
			(In thousands)		
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 June 30, 2014, we had \$9.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, \$1.8 million was used to offset current risk management liabilities under master netting arrangements and the remaining \$7.9 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 June 30, 2014				
Domestic equity mutual funds	$ 27,983	$ 10,274	$ —	$ 38,257
Foreign equity mutual funds	5,092	2,205	—	7,297
Bonds	33,180	220	(3)	33,397
Money market funds	1,959	—	—	1,959
	$ 68,214	$ 12,699	$ (3)	$ 80,910
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 June 30, 2014 and September 30, 2013, our available-for-sale securities included $47.5 million and $44.5 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At June 30, 2014, we maintained investments in bonds that have contractual maturity dates ranging from July 2014 through December 2019. During the nine months ended June 30, 2014 and 2013, we recognized gains of $1.1 million and $2.2 million on the sale of certain assets in the rabbi trusts.

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 June 30, 2014 and September 30, 2013:

	June 30, 2014	September 30, 2013
	(In thousands)	
Carrying Amount	$ 2,460,000	$ 2,460,000
Fair Value	$ 2,795,188	$ 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 nine months ended June 30, 2014, 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 June 30, 2013, net income from discontinued operations includes the aforementioned gain on sale, while for the nine months ended June 30, 2013, net income from discontinued operations includes the operating results of our Georgia operations and the gain on sale. 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 June 30, 2014 and September 30, 2013 we did not have any assets or liabilities held for sale.

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
	(In thousands)			
Operating revenues	$ —	$ —	$ —	$ 37,962
Purchased gas cost	—	—	—	21,464
Gross profit	—	—	—	16,498
Operating expenses	—	—	—	5,858
Operating income	—	—	—	10,640
Other nonoperating income	—	—	—	548
Income from discontinued operations before income taxes	—	—	—	11,188
Income tax expense	—	—	—	3,986
Income from discontinued operations	—	—	—	7,202
Gain on sale of discontinued operations, net of tax	—	5,294	—	5,294
Net income from discontinued operations	$ —	$ 5,294	$ —	$ 12,496

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 June 30, 2014, the related condensed consolidated statements of income and comprehensive income for the three and nine-month periods ended June 30, 2014 and 2013, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2014 and 2013. 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
August 6, 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", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; 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 June 30, 2014 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.

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 nine months ended June 30, 2014.

RESULTS OF OPERATIONS

Executive Summary

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.

Consolidated income from continuing operations for the nine months ended June 30, 2014 increased 19 percent period over period as a result of positive rate outcomes combined with increased gross profit associated with weather that was 20 percent colder than the prior-year period. Rate increases received in our regulated segments increased gross profit by $50.8 million. As of June 30, 2014, we had completed 14 regulatory proceedings in our regulated segments resulting in an $86.0 million increase in annual operating income and had six ratemaking efforts in progress seeking $49.6 million of additional annual operating income.

Regulated gross profit increased $17.6 million due to increased customer consumption in our natural gas distribution segment and increased throughput and related margins in our regulated transportation segment associated with colder weather. The colder than normal weather also increased market demand for natural gas, which drove higher price volatility, particularly during our second fiscal quarter. As a result, realized gross margin in our nonregulated operations increased $25.3 million period over period primarily from trading gains captured during the second fiscal quarter.

During the first nine months of fiscal 2014, our capital expenditures were $552.6 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 and debt and equity securities, while maintaining a balanced capital structure.

On February 18, 2014, we completed the sale of 9,200,000 shares of common stock, including the underwriters' exercise of their overallotment option of 1,200,000 shares, under our shelf registration statement, generating net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

Our debt-to-capitalization ratio as of June 30, 2014 was 44.1 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 effectively 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 in the first quarter of fiscal 2014.

Consolidated Results

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2014 and 2013:

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
	(In thousands, except per share data)			
Operating revenues	$ 942,718	$ 857,935	$ 4,162,188	$ 3,201,086
Gross profit	359,533	316,497	1,244,767	1,111,610
Operating expenses	252,928	230,101	717,362	660,114
Operating income	106,605	86,396	527,405	451,496
Miscellaneous income (expense)	(374)	(467)	(4,022)	1,943
Interest charges	31,840	32,741	95,556	96,594
Income from continuing operations before income taxes	74,391	53,188	427,827	356,845
Income tax expense	28,670	19,714	161,723	133,683
Income from continuing operations	45,721	33,474	266,104	223,162
Income from discontinued operations, net of tax	—	—	—	7,202
Gain on sale of discontinued operations, net of tax	—	5,294	—	5,294
Net income	$ 45,721	$ 38,768	$ 266,104	$ 235,658
Diluted net income per share from continuing operations	$ 0.45	$ 0.36	$ 2.76	$ 2.43
Diluted net income per share from discontinued operations	—	0.06	—	0.14
Diluted net income per share	$ 0.45	$ 0.42	$ 2.76	$ 2.57

Our consolidated net income during the three and nine month periods ended June 30, 2014 and 2013 was earned in each of our business segments as follows:

	Three Months Ended June 30		
	2014	2013	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$ 18,529	$ 15,817	$ 2,712
Regulated transmission and storage segment	24,938	23,097	1,841
Nonregulated segment	2,254	(5,440)	7,694
Net income from continuing operations	45,721	33,474	12,247
Net income from discontinued operations	—	5,294	(5,294)
Net income	$ 45,721	$ 38,768	$ 6,953

	Nine Months Ended June 30		
	2014	2013	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$ 170,029	$ 155,100	$ 14,929
Regulated transmission and storage segment	68,493	55,732	12,761
Nonregulated segment	27,582	12,330	15,252
Net income from continuing operations	266,104	223,162	42,942
Net income from discontinued operations	—	12,496	(12,496)
Net income	$ 266,104	$ 235,658	$ 30,446

Regulated operations contributed 95 percent and 90 percent to our consolidated net income for the three and nine months ended June 30, 2014. 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 June 30		
	2014	2013	Change
	(In thousands, except per share data)		
Regulated operations	$ 43,467	$ 38,914	$ 4,553
Nonregulated operations	2,254	(5,440)	7,694
Net income from continuing operations	45,721	33,474	12,247
Net income from discontinued operations	—	5,294	(5,294)
Net income	$ 45,721	$ 38,768	$ 6,953
Diluted EPS from continuing regulated operations	$ 0.43	$ 0.42	$ 0.01
Diluted EPS from nonregulated operations	0.02	(0.06)	0.08
Diluted EPS from continuing operations	0.45	0.36	0.09
Diluted EPS from discontinued operations	—	0.06	(0.06)
Consolidated diluted EPS	$ 0.45	$ 0.42	$ 0.03

	Nine Months Ended June 30		
	2014	2013	Change
	(In thousands, except per share data)		
Regulated operations	$ 238,522	210,832	$ 27,690
Nonregulated operations	27,582	12,330	15,252
Net income from continuing operations	266,104	223,162	42,942
Net income from discontinued operations	—	12,496	(12,496)
Net income	$ 266,104	$ 235,658	$ 30,446
Diluted EPS from continuing regulated operations	$ 2.47	$ 2.30	$ 0.17
Diluted EPS from nonregulated operations	0.29	0.13	0.16
Diluted EPS from continuing operations	2.76	2.43	0.33
Diluted EPS from discontinued operations	—	0.14	(0.14)
Consolidated diluted EPS	$ 2.76	$ 2.57	$ 0.19

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 June 30, 2014 compared with Three Months Ended June 30, 2013

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2014 and 2013 are presented below.

	Three Months Ended June 30		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 257,665	$ 239,495	$ 18,170
Operating expenses	203,132	187,544	15,588
Operating income	54,533	51,951	2,582
Miscellaneous income	678	268	410
Interest charges	23,649	25,001	(1,352)
Income from continuing operations before income taxes	31,562	27,218	4,344
Income tax expense	13,033	11,401	1,632
Income from continuing operations	18,529	15,817	2,712
Gain on sale of discontinued operations, net of tax	—	5,649	(5,649)
Net income	$ 18,529	$ 21,466	$ (2,937)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	39,341	43,190	(3,849)
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	32,997	29,179	3,818
Consolidated natural gas distribution throughput from continuing operations — MMcf	72,338	72,369	(31)
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	—	—
Total consolidated natural gas distribution throughput — MMcf	72,338	72,369	(31)
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.46	$ 0.45	$ 0.01
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 6.61	$ 5.27	$ 1.34

Income from continuing operations for our natural gas distribution segment increased 17 percent, primarily due to an $18.2 million increase in gross profit, partially offset by a $15.6 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $9.2 million net increase in rate adjustments, primarily in our Mid-Tex and West Texas Divisions.
- a $2.7 million increase in other revenue, primarily consisting of late payment fees and installment plan surcharges.
- a $6.7 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $10.9 million increase in the related tax expense.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to the aforementioned increased revenue-related tax expense and increased depreciation expense as a result of increased capital investments.

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 June 30, 2014 and 2013. 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 June 30		
	2014	2013	Change
		(In thousands)	
Mid-Tex	$ 26,100	$ 30,457	$ (4,357)
Kentucky/Mid-States	5,724	5,498	226
Louisiana	7,713	7,543	170
West Texas	3,785	3,678	107
Mississippi	(1,520)	1,634	(3,154)
Colorado-Kansas	1,369	2,076	(707)
Other	11,362	1,065	10,297
Total	$ 54,533	$ 51,951	$ 2,582

Nine Months Ended June 30, 2014 compared with Nine Months Ended June 30, 2013

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2014 and 2013 are presented below.

	Nine Months Ended June 30		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 942,024	$ 866,132	$ 75,892
Operating expenses	596,832	544,658	52,174
Operating income	345,192	321,474	23,718
Miscellaneous income	304	2,728	(2,424)
Interest charges	69,802	74,228	(4,426)
Income from continuing operations before income taxes	275,694	249,974	25,720
Income tax expense	105,665	94,874	10,791
Income from continuing operations	170,029	155,100	14,929
Income from discontinued operations, net of tax	—	7,202	(7,202)
Gain on sale of discontinued operations, net of tax	—	5,649	(5,649)
Net income	$ 170,029	$ 167,951	$ 2,078
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	288,702	242,066	46,636
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	105,608	98,608	7,000
Consolidated natural gas distribution throughput from continuing operations — MMcf	394,310	340,674	53,636
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	4,731	(4,731)
Total consolidated natural gas distribution throughput — MMcf	394,310	345,405	48,905
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.45	$ 0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.92	$ 4.86	$ 1.06

Income from continuing operations for our natural gas distribution segment increased 10 percent, primarily due to a $75.9 million increase in gross profit, partially offset by a $52.2 million increase in operating expenses. The year to date increase in gross profit primarily reflects:

- a $24.5 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky and Louisiana service areas.
- a $12.9 million increase due to increased customer consumption resulting from colder weather, primarily experienced in our Mid-Tex and West Texas Divisions.
- a $24.5 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $25.2 million increase in the related tax expense.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to the aforementioned increased revenue-related tax expense, increased levels and timing of incentive compensation expense resulting from improved operating results, increased labor costs primarily associated with increased standby and overtime costs and lower labor capitalization rates as employees incurred more time compared to the prior-year period to ensure our distribution system was safe and reliable during the colder than normal weather.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the nine months ended June 30, 2014 and 2013. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2014	2013	Change
		(In thousands)	
Mid-Tex	$ 151,009	$ 135,747	$ 15,262
Kentucky/Mid-States	53,243	45,700	7,543
Louisiana	51,131	48,432	2,699
West Texas	27,591	28,264	(673)
Mississippi	31,457	33,072	(1,615)
Colorado-Kansas	26,785	27,497	(712)
Other	3,976	2,762	1,214
Total	$ 345,192	$ 321,474	$ 23,718

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 nine months of fiscal 2014, we completed 13 regulatory proceedings, resulting in a $40.4 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Infrastructure programs	$ 6,092
Annual rate filing mechanisms	18,685
Rate case filings	15,872
Other rate activity	(226)
	$ 40,423

Additionally, the following ratemaking efforts seeking $49.6 million in annual operating income were in progress as of June 30, 2014:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Rate Case	Kansas	$ 7,005
Colorado-Kansas	Rate Case	Colorado	4,847
Kentucky/Mid-States	Rate Case	Virginia	2,128
Kentucky/Mid-States	Infrastructure Program	Virginia	170
Louisiana	Rate Stabilization Clause[(1)]	LGS	2,046
Mid-Tex	Rate Review Mechanism [(2)]	Mid-Tex Cities	33,415
			$ 49,611

(1) On July 1, 2014, an operating income increase of $1.4 million was implemented for the LGS rate stabilization clause.

(2) Mid-Tex Cities RRM rates were put into effect on June 1, 2014, subject to refund. The Company appealed the Mid-Tex Cities decision to deny the 2013 RRM increase to the Texas Railroad Commission on May 30, 2014. A hearing for the appeal is currently set to begin September 3, 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 June 30, 2014, we had infrastructure programs approved in Kansas, Kentucky, Louisiana, Texas and Virginia. The following table summarizes our infrastructure program filings with effective dates occurring during the nine months ended June 30, 2014.

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2014 Infrastructure Programs:				
West Texas[(1)]	12/2013	$ 58,841	$ 858	06/17/2014
Mid-Tex - Environs[(2)]	12/2013	203,714	881	05/22/2014
Colorado-Kansas - Kansas	09/2013	9,323	882	02/01/2014
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[(2)]	12/2012	164,681	768	10/01/2013
Total 2014 Infrastructure Programs		$ 455,634	$ 6,092	

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

(2) Incremental net utility plan 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 June 30, 2014 we had annual rate filing mechanisms in our Louisiana and Mississippi service areas and in our Texas divisions. These mechanisms are referred to as the Dallas annual rate review (DARR) and rate review mechanism (RRM) in our Mid-Tex and West Texas Divisions, stable rate filings in the Mississippi Division and rate stabilization clause in the Louisiana Division. The following annual rate filing mechanisms were completed during the nine months ended June 30, 2014.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
			(In thousands)	
2014 Filings:				
Mid-Tex	City of Dallas	09/30/2013	$ 5,638	06/01/2014
Louisiana	Trans LA	09/30/2013	550	04/01/2014
Mid-Tex	Mid-Tex Cities	12/31/2012	12,497	11/01/2013
Total 2014 Filings			$ 18,685	

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate cases that were completed during the nine months ended June 30, 2014.

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2014 Rate Case Filings:			
Kentucky/Mid-States	Kentucky	$ 5,823	04/22/2014
West Texas	Texas	8,440	04/01/2014
Colorado-Kansas	Colorado	1,609	03/01/2014
Total 2014 Rate Case Filings		$ 15,872	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2014.

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2014 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[1]	$ (226)	02/01/2014
Total 2014 Other Rate Activity			$ (226)	

(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.

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 June 30, 2014 compared with Three Months Ended June 30, 2013

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2014 and 2013 are presented below.

	Three Months Ended June 30		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 63,313	$ 47,117	$ 16,196
Third-party transportation	20,413	18,122	2,291
Storage and park and lend services	1,086	1,412	(326)
Other	2,377	7,390	(5,013)
Gross profit	87,189	74,041	13,148
Operating expenses	38,905	29,998	8,907
Operating income	48,284	44,043	4,241
Miscellaneous expense	(489)	(247)	(242)
Interest charges	9,162	8,049	1,113
Income before income taxes	38,633	35,747	2,886
Income tax expense	13,695	12,650	1,045
Net income	$ 24,938	$ 23,097	$ 1,841
Gross pipeline transportation volumes — MMcf	160,038	153,216	6,822
Consolidated pipeline transportation volumes — MMcf	127,979	121,194	6,785

Net income for our regulated transmission and storage segment increased 8 percent, primarily due to a $13.1 million increase in gross profit, partially offset by an $8.9 million increase in operating expenses. The increase in gross profit primarily reflects a $12.2 million increase in rates from the approved 2014 GRIP filing. On May 6, 2014, the RRC approved the Atmos Pipeline — Texas GRIP filing with an annual operating income increase of $45.6 million that went into effect with bills rendered on and after May 6, 2014.

Operating expenses increased $8.9 million primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system.

Nine Months Ended June 30, 2014 compared with Nine Months Ended June 30, 2013

Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2014 and 2013 are presented below.

	Nine Months Ended June 30		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 163,818	$ 130,849	$ 32,969
Third-party transportation	56,457	47,440	9,017
Storage and park and lend services	4,336	4,484	(148)
Other	7,534	13,797	(6,263)
Gross profit	232,145	196,570	35,575
Operating expenses	96,173	87,014	9,159
Operating income	135,972	109,556	26,416
Miscellaneous expense	(2,751)	(473)	(2,278)
Interest charges	27,274	22,777	4,497
Income before income taxes	105,947	86,306	19,641
Income tax expense	37,454	30,574	6,880
Net income	$ 68,493	$ 55,732	$ 12,761
Gross pipeline transportation volumes — MMcf	559,824	493,721	66,103
Consolidated pipeline transportation volumes — MMcf	362,583	335,036	27,547

Net income for our regulated transmission and storage segment increased 23 percent, primarily due to a $35.6 million increase in gross profit. The increase in gross profit primarily reflects a $26.3 million increase in rates from the GRIP filings approved by the RRC in fiscal 2014 and 2013 coupled with a $4.7 million increase associated with higher throughput and basis spreads driven by colder weather.

The Atmos Pipeline — Texas 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 the non-regulated annual revenue of Atmos Pipeline — Texas 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 the next Atmos Pipeline — Texas 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.

Operating expenses increased $9.2 million primarily due to increased depreciation expense associated with increased capital investments, increased levels of pipeline and right-of-way maintenance activities and higher employee-related expenses, partially offset by a $6.7 million refund received as a result of the completion of a state use tax audit.

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and, for the fiscal year ended September 30, 2013, represented 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 June 30, 2014 compared with Three Months Ended June 30, 2013

Financial and operating highlights for our nonregulated segment for the three months ended June 30, 2014 and 2013 are presented below.

	Three Months Ended June 30		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 7,871	$ 5,945	$ 1,926
Storage and transportation services	3,603	3,689	(86)
Other	4,004	3,322	682
Total realized margins	15,478	12,956	2,522
Unrealized margins	(665)	(9,696)	9,031
Gross profit	14,813	3,260	11,553
Operating expenses	11,025	12,860	(1,835)
Operating income (loss)	3,788	(9,600)	13,388
Miscellaneous income	1,018	215	803
Interest charges	610	392	218
Income (loss) before income taxes	4,196	(9,777)	13,973
Income tax expense (benefit)	1,942	(4,337)	6,279
Income (loss) from continuing operations	2,254	(5,440)	7,694
Loss on sale of discontinued operations, net of tax	—	(355)	355
Net income (loss)	$ 2,254	$ (5,795)	$ 8,049
Gross nonregulated delivered gas sales volumes — MMcf	96,119	97,388	(1,269)
Consolidated nonregulated delivered gas sales volumes — MMcf	82,074	83,341	(1,267)
Net physical position (Bcf)	6.6	19.2	(12.6)

The $11.6 million quarter-over-quarter increase in gross profit reflected a $2.5 million increase in realized margins, combined with a $9.0 million increase in unrealized margins. The $2.5 million increase in realized margins primarily reflects a $1.9 million increase in gas delivery and related services margins. Gas delivery per-unit margins increased from 6 cents per Mcf in the prior-year quarter to 8 cents, which reflects favorable financial settlements associated with fixed-price purchases compared to the contractual sales price to the customer. The increases in per-unit margins were partially offset by lower consolidated sales volumes which decrease two percent as a result of warmer spring temperatures which reduced deliveries to marketing customers.

Unrealized margins increased $9.0 million primarily due to the quarter-over-quarter timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses decreased $1.8 million, primarily due to lower legal-related expenses.

Nine Months Ended June 30, 2014 compared with Nine Months Ended June 30, 2013

Financial and operating highlights for our nonregulated segment for the nine months ended June 30, 2014 and 2013 are presented below.

	Nine Months Ended June 30		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 32,783	$ 31,279	$ 1,504
Storage and transportation services	10,815	10,806	9
Other	15,831	(7,982)	23,813
Total realized margins	59,429	34,103	25,326
Unrealized margins	11,539	15,923	(4,384)
Gross profit	70,968	50,026	20,942
Operating expenses	24,727	29,565	(4,838)
Operating income	46,241	20,461	25,780
Miscellaneous income	1,785	1,791	(6)
Interest charges	1,840	1,687	153
Income before income taxes	46,186	20,565	25,621
Income tax expense	18,604	8,235	10,369
Income from continuing operations	27,582	12,330	15,252
Loss on sale of discontinued operations, net of tax	—	(355)	355
Net income	$ 27,582	$ 11,975	$ 15,607
Gross nonregulated delivered gas sales volumes — MMcf	343,451	306,120	37,331
Consolidated nonregulated delivered gas sales volumes — MMcf	294,678	265,791	28,887
Net physical position (Bcf)	6.6	19.2	(12.6)

Net income for our nonregulated segment increased 130 percent from the prior year due to higher gross profit and decreased operating expenses.

The $20.9 million period-over-period increase in gross profit reflected a $25.3 million increase in realized margins, offset by a $4.4 million decrease in unrealized margins. The $25.3 million increase in realized margins reflects:

- A $23.8 million increase in other realized margins due to the acceleration of physical withdrawals into the second quarter from future periods to capture gross profit margin during periods of increased natural gas price volatility caused by strong market demand as a result of significantly colder weather during the second quarter. In contrast, losses were incurred from storage optimization activities in the prior year largely due to unfavorable changes in market prices relative to the execution strategy in place at that time.
- A $1.5 million increase in gas delivery and related services margins. Consolidated sales volumes increased 11 percent as a result of stronger demand from marketing, industrial and utility/municipal customers due to colder weather. Additionally, gas delivery per-unit margins decreased from 10.2 cents per Mcf in the prior-year period to 9.5 cents per Mcf due primarily to losses incurred during the second quarter to meet peaking requirements for certain customers during periods of colder weather, due to volatility between spot purchase prices and the contractual sales price to the customer.

Unrealized margins decreased $4.4 million primarily due to the period-over-period timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses decreased $4.8 million, primarily due to lower legal expenses related to the dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 7 to the financial statements.

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. To support our capital market activities, we have a shelf registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

As of June 30, 2014, approximately $1.35 billion of securities remained available for issuance under the shelf registration statement until March 28, 2016.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2014, September 30, 2013 and June 30, 2013:

	June 30, 2014		September 30, 2013		June 30, 2013	
			(In thousands, except percentages)			
Short-term debt	$ —	—%	$ 367,984	6.8%	$ 141,998	2.7%
Long-term debt(1)	2,455,907	44.1%	2,455,671	45.4%	2,455,593	47.4%
Shareholders' equity	3,116,685	55.9%	2,580,409	47.8%	2,581,444	49.9%
Total	$ 5,572,592	100.0%	$ 5,404,064	100.0%	$ 5,179,035	100.0%

(1) 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 effectively 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 44.1 percent at June 30, 2014, 52.2 percent at September 30, 2013 and 50.1 percent at June 30, 2013.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, 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 nine months ended June 30, 2014 and 2013 are presented below.

	Nine Months Ended June 30		
	2014	2013	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 630,210	$ 509,575	$ 120,635
Investing activities	(553,220)	(432,589)	(120,631)
Financing activities	(91,768)	(109,246)	17,478
Change in cash and cash equivalents	(14,778)	(32,260)	17,482
Cash and cash equivalents at beginning of period	66,199	64,239	1,960
Cash and cash equivalents at end of period	$ 51,421	$ 31,979	$ 19,442

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 changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the nine months ended June 30, 2014, we generated cash flow of $630.2 million from operating activities compared with $509.6 million for the nine months ended June 30, 2013. The $120.6 million increase in operating cash flows primarily reflects higher operating results from colder weather and rate increases combined with the timing of customer collections and vendor payments.

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 nine months ended June 30, 2014, capital expenditures were $552.6 million, compared with $582.5 million in the prior-year period. The period-over-period decrease primarily reflects:

- A $51.5 million decrease in capital spending in our regulated transmission and storage segment primarily associated with the completion of the Line WX expansion project, partially offset by
- A $22.0 million increase in capital spending in our natural gas distribution segment due to increased spending under our infrastructure replacement programs.

Cash flows from financing activities

For the nine months ended June 30, 2014, our financing activities used $91.8 million of cash compared with $109.2 million used in the prior-year period. The decrease is primarily due to timing between short-term debt borrowings and repayments during the current year partially offset by proceeds from the equity offering completed in February 2014 compared with proceeds generated from the issuance of long-term debt in the prior-year period.

The following table summarizes our share issuances for the nine months ended June 30, 2014 and 2013.

	Nine Months Ended June 30	
	2014	2013
Shares issued:		
Direct stock purchase plan	41,907	—
1998 Long-Term Incentive Plan	653,130	531,372
Outside Directors Stock-for-Fee Plan	1,354	1,599
February 2014 Offering	9,200,000	—
Total shares issued	9,896,391	532,971

The year-over-year increase in the number of shares issued primarily reflects the equity offering completed in February 2014 as well as a higher number of performance-based awards issued in the current year as actual performance exceeded the target. For the nine months ended June 30, 2014 and 2013, we canceled and retired 190,134 and 133,351 shares attributable to federal income tax 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 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1 billion of working capital funding. As of June 30, 2014, the amount available to us under our credit facilities, net of outstanding letters of credit, was $1,031.4 million.

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 June 30, 2014, 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
Senior unsecured long-term debt	A-	A2	A-
Commercial paper	A-2	P-1	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 June 30, 2014. 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 nine months ended June 30, 2014.

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. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

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 and nine months ended June 30, 2014 and 2013:

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
	(In thousands)			
Fair value of contracts at beginning of period	$ 89,411	$ 40,126	$ 109,648	$ (76,260)
Contracts realized/settled	23	81	5,220	2,610
Fair value of new contracts	(902)	541	(36)	1,554
Other changes in value	(39,019)	45,640	(65,319)	158,484
Fair value of contracts at end of period	$ 49,513	$ 86,388	$ 49,513	$ 86,388

The fair value of our natural gas distribution segment's financial instruments at June 30, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2014				
	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	$ 35,829	$ 13,684	$ —	$ —	$ 49,513
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ 35,829	$ 13,684	$ —	$ —	$ 49,513

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and nine months ended June 30, 2014 and 2013:

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
	(In thousands)			
Fair value of contracts at beginning of period	$ 5,796	$ (4,019)	$ (14,700)	$ (15,123)
Contracts realized/settled	(3,220)	(2,193)	11,358	10,051
Fair value of new contracts	—	—	—	—
Other changes in value	762	1,889	6,680	749
Fair value of contracts at end of period	3,338	(4,323)	3,338	(4,323)
Netting of cash collateral	9,689	14,252	9,689	14,252
Cash collateral and fair value of contracts at period end	$ 13,027	$ 9,929	$ 13,027	$ 9,929

The fair value of our nonregulated segment's financial instruments at June 30, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2014				
	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	$ (1,771)	$ 5,143	$ (34)	$ —	$ 3,338
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (1,771)	$ 5,143	$ (34)	$ —	$ 3,338

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2014 and 2013, our total net periodic pension and other benefits costs were $53.5 million and $59.8 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 nine months ended June 30, 2014 we contributed $27.1 million to our defined benefit plans and we do not anticipate making any contributions in the fiscal 2014 fourth quarter. For the nine months ended June 30, 2014 we contributed $18.1 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 and nine month periods ended June 30, 2014 and 2013.

Natural Gas Distribution Sales and Statistical Data — Continuing Operations

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
METERS IN SERVICE, end of period				
Residential	2,751,812	2,751,599	2,751,812	2,751,599
Commercial	245,833	246,286	245,833	246,286
Industrial	1,466	1,502	1,466	1,502
Public authority and other	8,400	9,990	8,400	9,990
Total meters	3,007,511	3,009,377	3,007,511	3,009,377
INVENTORY STORAGE BALANCE — Bcf(1)	39.0	33.7	39.0	33.7
SALES VOLUMES — MMcf(2)				
Gas sales volumes				
Residential	19,555	22,668	175,884	143,920
Commercial	15,305	15,198	92,240	76,919
Industrial	3,074	3,408	12,898	12,891
Public authority and other	1,407	1,916	7,680	8,336
Total gas sales volumes	39,341	43,190	288,702	242,066
Transportation volumes	36,321	32,458	116,064	106,405
Total throughput	75,662	75,648	404,766	348,471
OPERATING REVENUES (000's)(2)				
Gas sales revenues				
Residential	$ 309,798	$ 289,363	$ 1,698,600	$ 1,301,264
Commercial	154,375	126,925	748,705	556,194
Industrial	19,458	19,303	74,003	65,059
Public authority and other	10,817	12,970	54,960	51,120
Total gas sales revenues	494,448	448,561	2,576,268	1,973,637
Transportation revenues	16,216	14,253	53,972	47,486
Other gas revenues	7,043	4,330	22,292	17,984
Total operating revenues	$ 517,707	$ 467,144	$ 2,652,532	$ 2,039,107
Average transportation revenue per Mcf(1)	$ 0.45	$ 0.44	$ 0.47	$ 0.45
Average cost of gas per Mcf sold(1)	$ 6.61	$ 5.27	$ 5.92	$ 4.86

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data — Discontinued Operations

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
Meters in service, end of period	—	—	—	—
Sales volumes — MMcf				
Total gas sales volumes	—	—	—	3,611
Transportation volumes	—	—	—	1,120
Total throughput	—	—	—	4,731
Operating revenues (000's)	$ —	$ —	$ —	$ 37,962

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2014	2013	2014	2013
CUSTOMERS, end of period				
Industrial	736	750	736	750
Municipal	128	133	128	133
Other	524	432	524	432
Total	1,388	1,315	1,388	1,315
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	10.9	22.2	10.9	22.2
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(2)	160,038	153,216	559,824	493,721
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(2)	96,119	97,388	343,451	306,120
OPERATING REVENUES (000's)(2)				
Regulated transmission and storage	$ 87,189	$ 74,041	$ 232,145	$ 196,570
Nonregulated	465,033	421,808	1,670,437	1,250,650
Total operating revenues	$ 552,222	$ 495,849	$ 1,902,582	$ 1,447,220

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 nine months ended June 30, 2014, 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 June 30, 2014 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 third 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 nine months ended June 30, 2014, 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: August 6, 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.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2014

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 ☑ 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 ☑ 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 ☑ 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 ☑

Number of shares outstanding of each of the issuer's classes of common stock, as of May 1, 2014.

Class	Shares Outstanding
No Par Value	100,186,395

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
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

	March 31, 2014	September 30, 2013
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 8,014,440	$ 7,722,019
Less accumulated depreciation and amortization	1,744,457	1,691,364
Net property, plant and equipment	6,269,983	6,030,655
Current assets		
Cash and cash equivalents	136,740	66,199
Accounts receivable, net	671,021	301,992
Gas stored underground	124,950	244,741
Other current assets	126,450	64,201
Total current assets	1,059,161	677,133
Goodwill	741,363	741,363
Deferred charges and other assets	417,109	485,117
	$ 8,487,616	$ 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: March 31, 2014 — 100,177,825 shares; September 30, 2013 — 90,640,211 shares	$ 501	$ 453
Additional paid-in capital	2,163,144	1,765,811
Retained earnings	924,282	775,267
Accumulated other comprehensive income	36,834	38,878
Shareholders' equity	3,124,761	2,580,409
Long-term debt	1,955,829	2,455,671
Total capitalization	5,080,590	5,036,080
Current liabilities		
Accounts payable and accrued liabilities	442,816	241,611
Other current liabilities	420,576	368,891
Short-term debt	—	367,984
Current maturities of long-term debt	500,000	—
Total current liabilities	1,363,392	978,486
Deferred income taxes	1,283,551	1,164,053
Regulatory cost of removal obligation	358,262	359,299
Pension and postretirement liabilities	360,851	358,787
Deferred credits and other liabilities	40,970	37,563
	$ 8,487,616	$ 7,934,268

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2014	2013
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 1,290,960	$ 905,176
Regulated transmission and storage segment	73,615	61,848
Nonregulated segment	757,683	428,948
Intersegment eliminations	(157,936)	(86,976)
	1,964,322	1,308,996
Purchased gas cost		
Natural gas distribution segment	905,772	558,170
Regulated transmission and storage segment	—	—
Nonregulated segment	720,094	404,641
Intersegment eliminations	(157,821)	(86,566)
	1,468,045	876,245
Gross profit	496,277	432,751
Operating expenses		
Operation and maintenance	124,675	111,086
Depreciation and amortization	61,307	57,180
Taxes, other than income	60,215	54,307
Total operating expenses	246,197	222,573
Operating income	250,080	210,178
Miscellaneous income (expense)	(1,516)	1,712
Interest charges	31,601	33,331
Income from continuing operations before income taxes	216,963	178,559
Income tax expense	83,596	66,219
Income from continuing operations	133,367	112,340
Income from discontinued operations, net of tax ($0 and $2,258)	—	4,085
Net income	$ 133,367	$ 116,425
Basic earnings per share		
Income per share from continuing operations	$ 1.40	$ 1.24
Income per share from discontinued operations	—	0.04
Net income per share — basic	$ 1.40	$ 1.28
Diluted earnings per share		
Income per share from continuing operations	$ 1.38	$ 1.23
Income per share from discontinued operations	—	0.04
Net income per share — diluted	$ 1.38	$ 1.27
Cash dividends per share	$ 0.37	$ 0.35
Weighted average shares outstanding:		
Basic	95,264	90,530
Diluted	96,191	91,492

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2014	2013
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$ 2,134,825	$ 1,571,963
Regulated transmission and storage segment	144,956	122,529
Nonregulated segment	1,205,404	828,842
Intersegment eliminations	(265,715)	(180,183)
	3,219,470	2,343,151
Purchased gas cost		
Natural gas distribution segment	1,450,466	945,326
Regulated transmission and storage segment	—	—
Nonregulated segment	1,149,249	782,076
Intersegment eliminations	(265,479)	(179,364)
	2,334,236	1,548,038
Gross profit	885,234	795,113
Operating expenses		
Operation and maintenance	240,432	217,613
Depreciation and amortization	121,776	116,759
Taxes, other than income	102,226	95,641
Total operating expenses	464,434	430,013
Operating income	420,800	365,100
Miscellaneous income (expense)	(3,648)	2,410
Interest charges	63,716	63,853
Income from continuing operations before income taxes	353,436	303,657
Income tax expense	133,053	113,969
Income from continuing operations	220,383	189,688
Income from discontinued operations, net of tax ($0 and $3,986)	—	7,202
Net income	$ 220,383	$ 196,890
Basic earnings per share		
Income per share from continuing operations	$ 2.36	$ 2.09
Income per share from discontinued operations	—	0.08
Net income per share — basic	$ 2.36	$ 2.17
Diluted earnings per share		
Income per share from continuing operations	$ 2.34	$ 2.07
Income per share from discontinued operations	—	0.08
Net income per share — diluted	$ 2.34	$ 2.15
Cash dividends per share	$ 0.74	$ 0.70
Weighted average shares outstanding:		
Basic	93,049	90,445
Diluted	93,976	91,406

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(Unaudited) (In thousands)			
Net income	$ 133,367	$ 116,425	$ 220,383	$ 196,890
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(133), $(110), $1,302 and $(330)	(252)	(200)	2,142	(573)
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(15,546), $13,513, $(7,533) and $20,562	(27,047)	23,509	(13,105)	35,773
Net unrealized gains on commodity cash flow hedges, net of tax of $703, $5,650, $5,702 and $5,417	1,101	8,838	8,919	8,473
Total other comprehensive income (loss)	(26,198)	32,147	(2,044)	43,673
Total comprehensive income	$ 107,169	$ 148,572	$ 218,339	$ 240,563

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31 2014	Six Months Ended March 31 2013
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 220,383	$ 196,890
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	121,776	118,608
Charged to other accounts	441	265
Deferred income taxes	119,710	106,891
Other	10,746	5,519
Net assets / liabilities from risk management activities	836	(14,709)
Net change in operating assets and liabilities	17,089	(37,123)
Net cash provided by operating activities	490,981	376,341
Cash Flows From Investing Activities		
Capital expenditures	(359,009)	(389,117)
Other, net	(4,904)	(3,700)
Net cash used in investing activities	(363,913)	(392,817)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(369,012)	(342,141)
Net proceeds from equity offering	390,205	—
Net proceeds from issuance of long-term debt	—	493,793
Settlement of Treasury lock agreements	—	(66,626)
Repayment of long-term debt	—	(131)
Cash dividends paid	(71,380)	(64,008)
Repurchase of equity awards	(6,317)	(3,124)
Other	(23)	21
Net cash provided by (used in) financing activities	(56,527)	17,784
Net increase in cash and cash equivalents	70,541	1,308
Cash and cash equivalents at beginning of period	66,199	64,239
Cash and cash equivalents at end of period	$ 136,740	$ 65,547

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2014

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 March 31, 2014, 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 North Texas 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.

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 six-month period ended March 31, 2014 are not indicative of our results of operations for the full 2014 fiscal year, which ends September 30, 2014.

Except as noted in Note 7 and Note 8, 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.

During the second quarter of fiscal 2014, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

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.

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. In connection with the adoption of this standard, prior-year risk management assets and liabilities have been reclassified to conform with the current-year presentation. The adoption of this standard and reclassification 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 nor were there new accounting standards announced during the six months ended March 31, 2014 that will become applicable to the Company in future periods.

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 March 31, 2014 and September 30, 2013 included the following:

	March 31, 2014	September 30, 2013
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs(1)	$ 176,616	$ 187,977
Merger and integration costs, net	4,990	5,250
Deferred gas costs	10,004	15,152
Regulatory cost of removal asset	9,716	10,008
Rate case costs	5,037	6,329
Texas Rule 8.209(2)	40,760	30,364
APT annual adjustment mechanism	4,084	5,853
Recoverable loss on reacquired debt	20,156	21,435
Other	6,393	4,380
	$ 277,756	$ 286,748
Regulatory liabilities:		
Deferred gas costs	$ 80,330	$ 16,481
Deferred franchise fees	11,523	1,689
Regulatory cost of removal obligation	425,461	427,524
Other	11,683	7,887
	$ 528,997	$ 453,581

(1) Includes $18.1 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

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 and six month periods ended March 31, 2014 and 2013 by segment are presented in the following tables:

	Three Months Ended March 31, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,289,429	$ 21,002	$ 653,891	$ —	$ 1,964,322
Intersegment revenues	1,531	52,613	103,792	(157,936)	—
	1,290,960	73,615	757,683	(157,936)	1,964,322
Purchased gas cost	905,772	—	720,094	(157,821)	1,468,045
Gross profit	385,188	73,615	37,589	(115)	496,277
Operating expenses					
Operation and maintenance	106,776	16,595	1,419	(115)	124,675
Depreciation and amortization	50,020	10,156	1,131	—	61,307
Taxes, other than income	60,606	(1,232)	841	—	60,215
Total operating expenses	217,402	25,519	3,391	(115)	246,197
Operating income	167,786	48,096	34,198	—	250,080
Miscellaneous income (expense)	97	(1,081)	443	(975)	(1,516)
Interest charges	22,828	9,155	593	(975)	31,601
Income before income taxes	145,055	37,860	34,048	—	216,963
Income tax expense	56,312	13,751	13,533	—	83,596
Net income	$ 88,743	$ 24,109	$ 20,515	$ —	$ 133,367
Capital expenditures	$ 139,555	$ 39,000	$ (113)	$ —	$ 178,442

	Three Months Ended March 31, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 904,181	$ 19,655	$ 385,160	$ —	$ 1,308,996
Intersegment revenues	995	42,193	43,788	(86,976)	—
	905,176	61,848	428,948	(86,976)	1,308,996
Purchased gas cost	558,170	—	404,641	(86,566)	876,245
Gross profit	347,006	61,848	24,307	(410)	432,751
Operating expenses					
Operation and maintenance	89,344	15,390	6,763	(411)	111,086
Depreciation and amortization	47,631	8,690	859	—	57,180
Taxes, other than income	49,592	4,277	438	—	54,307
Total operating expenses	186,567	28,357	8,060	(411)	222,573
Operating income	160,439	33,491	16,247	1	210,178
Miscellaneous income (expense)	2,591	(99)	(91)	(689)	1,712
Interest charges	25,664	7,857	498	(688)	33,331
Income from continuing operations before income taxes	137,366	25,535	15,658	—	178,559
Income tax expense	51,176	9,005	6,038	—	66,219
Income from continuing operations	86,190	16,530	9,620	—	112,340
Income from discontinued operations, net of tax	4,085	—	—	—	4,085
Net income	$ 90,275	$ 16,530	$ 9,620	$ —	$ 116,425
Capital expenditures	$ 131,465	$ 67,208	$ 417	$ —	$ 199,090

	Six Months Ended March 31, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,131,861	$ 42,172	$ 1,045,437	$ —	$ 3,219,470
Intersegment revenues	2,964	102,784	159,967	(265,715)	—
	2,134,825	144,956	1,205,404	(265,715)	3,219,470
Purchased gas cost	1,450,466	—	1,149,249	(265,479)	2,334,236
Gross profit	684,359	144,956	56,155	(236)	885,234
Operating expenses					
Operation and maintenance	196,439	33,895	10,334	(236)	240,432
Depreciation and amortization	99,571	19,942	2,263	—	121,776
Taxes, other than income	97,690	3,431	1,105	—	102,226
Total operating expenses	393,700	57,268	13,702	(236)	464,434
Operating income	290,659	87,688	42,453	—	420,800
Miscellaneous income (expense)	(374)	(2,262)	767	(1,779)	(3,648)
Interest charges	46,153	18,112	1,230	(1,779)	63,716
Income from before income taxes	244,132	67,314	41,990	—	353,436
Income tax expense	92,632	23,759	16,662	—	133,053
Net income	$ 151,500	$ 43,555	$ 25,328	$ —	$ 220,383
Capital expenditures	$ 267,061	$ 91,921	$ 27	$ —	$ 359,009

	Six Months Ended March 31, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,569,730	$ 38,354	$ 735,067	$ —	$ 2,343,151
Intersegment revenues	2,233	84,175	93,775	(180,183)	—
	1,571,963	122,529	828,842	(180,183)	2,343,151
Purchased gas cost	945,326	—	782,076	(179,364)	1,548,038
Gross profit	626,637	122,529	46,766	(819)	795,113
Operating expenses					
Operation and maintenance	173,080	31,710	13,645	(822)	217,613
Depreciation and amortization	97,691	17,080	1,988	—	116,759
Taxes, other than income	86,343	8,226	1,072	—	95,641
Total operating expenses	357,114	57,016	16,705	(822)	430,013
Operating income	269,523	65,513	30,061	3	365,100
Miscellaneous income (expense)	2,460	(226)	1,576	(1,400)	2,410
Interest charges	49,227	14,728	1,295	(1,397)	63,853
Income from continuing operations before income taxes	222,756	50,559	30,342	—	303,657
Income tax expense	83,473	17,924	12,572	—	113,969
Income from continuing operations	139,283	32,635	17,770	—	189,688
Income from discontinued operations, net of tax	7,202	—	—	—	7,202
Net income	$ 146,485	$ 32,635	$ 17,770	$ —	$ 196,890
Capital expenditures	$ 277,336	$ 111,039	$ 742	$ —	$ 389,117

Balance sheet information at March 31, 2014 and September 30, 2013 by segment is presented in the following tables.

	March 31, 2014				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 4,889,160	$ 1,322,441	$ 58,382	$ —	$ 6,269,983
Investment in subsidiaries	908,939	—	(2,096)	(906,843)	—
Current assets					
Cash and cash equivalents	73,165	—	63,575	—	136,740
Assets from risk management activities	58,746	—	7,940	—	66,686
Other current assets	609,806	14,363	610,515	(378,949)	855,735
Intercompany receivables	786,428	—	—	(786,428)	—
Total current assets	1,528,145	14,363	682,030	(1,165,377)	1,059,161
Goodwill	574,190	132,462	34,711	—	741,363
Noncurrent assets from risk management activities	30,665	—	8,910	—	39,575
Deferred charges and other assets	350,362	19,585	7,587	—	377,534
	$ 8,281,461	$ 1,488,851	$ 789,524	$ (2,072,220)	$ 8,487,616
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,124,761	$ 439,977	$ 468,962	$ (908,939)	$ 3,124,761
Long-term debt	1,955,829	—	—	—	1,955,829
Total capitalization	5,080,590	439,977	468,962	(908,939)	5,080,590
Current liabilities					
Current maturities of long-term debt	500,000	—	—	—	500,000
Short-term debt	343,000	—	—	(343,000)	—
Other current liabilities	658,106	13,654	225,485	(33,853)	863,392
Intercompany payables	—	708,046	78,382	(786,428)	—
Total current liabilities	1,501,106	721,700	303,867	(1,163,281)	1,363,392
Deferred income taxes	943,831	324,879	14,841	—	1,283,551
Regulatory cost of removal obligation	358,262	—	—	—	358,262
Pension and postretirement liabilities	360,851	—	—	—	360,851
Deferred credits and other liabilities	36,821	2,295	1,854	—	40,970
	$ 8,281,461	$ 1,488,851	$ 789,524	$ (2,072,220)	$ 8,487,616

	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
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	8,849	—	375,763
	$ 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 and six months ended March 31, 2014 and 2013 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Basic Earnings Per Share from continuing operations				
Income from continuing operations	$ 133,367	$ 112,340	$ 220,383	$ 189,688
Less: Income from continuing operations allocated to participating securities	337	304	578	634
Income from continuing operations available to common shareholders	$ 133,030	$ 112,036	$ 219,805	$ 189,054
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Income from continuing operations per share — Basic	$ 1.40	$ 1.24	$ 2.36	$ 2.09
Basic Earnings Per Share from discontinued operations				
Income from discontinued operations	$ —	$ 4,085	$ —	$ 7,202
Less: Income from discontinued operations allocated to participating securities	—	11	—	24
Income from discontinued operations available to common shareholders	$ —	$ 4,074	$ —	$ 7,178
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Income from discontinued operations per share — Basic	$ —	$ 0.04	$ —	$ 0.08
Net income per share — Basic	$ 1.40	$ 1.28	$ 2.36	$ 2.17

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Diluted Earnings Per Share from continuing operations				
Income from continuing operations available to common shareholders	$ 133,030	$ 112,036	$ 219,805	$ 189,054
Effect of dilutive stock options and other shares	2	2	4	5
Income from continuing operations available to common shareholders	$ 133,032	$ 112,038	$ 219,809	$ 189,059
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Additional dilutive stock options and other shares	927	962	927	961
Diluted weighted average shares outstanding	96,191	91,492	93,976	91,406
Income from continuing operations per share — Diluted	$ 1.38	$ 1.23	$ 2.34	$ 2.07
Diluted Earnings Per Share from discontinued operations				
Income from discontinued operations available to common shareholders	$ —	$ 4,074	$ —	$ 7,178
Effect of dilutive stock options and other shares	—	—	—	—
Income from discontinued operations available to common shareholders	$ —	$ 4,074	$ —	$ 7,178
Basic weighted average shares outstanding	95,264	90,530	93,049	90,445
Additional dilutive stock options and other shares	927	962	927	961
Diluted weighted average shares outstanding	96,191	91,492	93,976	91,406
Income from discontinued operations per share — Diluted	$ —	$ 0.04	$ —	$ 0.08
Net income per share — Diluted	$ 1.38	$ 1.27	$ 2.34	$ 2.15

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and six months ended March 31, 2014 and 2013 as their exercise price was less than the average market price of the common stock during those periods.

2014 Equity Offering

On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares under our existing shelf registration statement. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

2011 Share Repurchase Program

We did not repurchase any shares during the six months ended March 31, 2014 and 2013 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 six months ended March 31, 2014.

Long-term debt

Long-term debt at March 31, 2014 and September 30, 2013 consisted of the following:

	March 31, 2014	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	4,171	4,329
Current maturities	500,000	—
	$ 1,955,829	$ 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 billion of working capital funding. At March 31, 2014, there were no short-term debt borrowings outstanding. At September 30, 2013, there was a total of $368.0 million 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 increase 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 March 31, 2014.

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. In December 2013, the $25 million 364-day uncommitted bilateral facility was extended to December 2014. In January 2014, this facility was amended to temporarily increase the amount available 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. The $25 million committed bilateral facility was replaced with a $15 million committed 364-day bilateral credit facility in December 2013. 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 $33.7 million at March 31, 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 filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013 that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February 18, 2014, we completed the public offering of 9,200,000 shares of our common stock, which generated net proceeds of $390.2 million. As of March 31, 2014, $1.35 billion of securities remained available for issuance under the shelf registration statement until March 28, 2016.

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 March 31, 2014, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 46 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 March 31, 2014. 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 and six months ended March 31, 2014 and 2013 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 executive officers, 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 March 31			
	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,738	$ 5,203	$ 4,196	$ 4,700
Interest cost	6,824	6,023	3,988	3,241
Expected return on assets	(5,900)	(5,738)	(1,292)	(997)
Amortization of transition obligation	—	—	68	270
Amortization of prior service credit	(34)	(36)	(362)	(363)
Amortization of actuarial loss	3,930	5,562	158	1,049
Net periodic pension cost	$ 9,558	$ 11,014	$ 6,756	$ 7,900

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 9,476	$ 10,405	$ 8,392	$ 9,400
Interest cost	13,648	12,048	7,976	6,482
Expected return on assets	(11,801)	(11,477)	(2,584)	(1,994)
Amortization of transition obligation	—	—	136	540
Amortization of prior service credit	(68)	(71)	(725)	(725)
Amortization of actuarial loss	7,862	11,123	316	2,098
Settlement loss	4,539	—	—	—
Net periodic pension cost	$ 23,656	$ 22,028	$ 13,511	$ 15,801

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2014 and 2013 are as follows:

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
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 six months of fiscal 2014, we contributed $9.1 million to our defined benefit plans and we anticipate contributing approximately $10 million to $35 million during fiscal 2014.

We contributed $11.6 million to our other post-retirement benefit plans during the six months ended March 31, 2014. We expect to contribute a total of approximately $20 million to $25 million to these plans during fiscal 2014.

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 six months ended March 31, 2014.

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 responses to the motions. The Kentucky Supreme Court denied the motions for discretionary review on February 12, 2014. The decision of the Court of Appeals became final on February 21, 2014. Atmos has filed a motion with the trial court for entry of judgment dismissing all claims against it, except for the trespass claim. Atmos' motion seeks a ruling by the trial court that the remaining landowner is not entitled to any punitive damages on that claim. That motion is currently scheduled to be heard on May 19, 2014.

We had previously accrued what we believed to be an adequate amount for the anticipated resolution of this matter. This accrual was reversed during the second fiscal quarter as the appellate process in this case has been completed.

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. Discovery has been completed, and dispositive motions are due on June 30, 2014. This case is scheduled for trial beginning October 6, 2014.

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. The cumulative assessment approximated $12 million as of March 31, 2014, which AEM has challenged. We had previously accrued in prior years what we believed to be an adequate amount for the anticipated resolution of this matter. 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. A filing deadline was set for filing any cross motions for partial summary judgment as to the remaining issues. On May 2, 2014, the Company and the TDOR executed an agreed order of dismissal with prejudice whereby AEM agreed to pay $6.2 million to resolve all business tax-related liabilities outstanding through September 2014. The order of dismissal will become effective upon approval of the Chancery Court.

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 March 31, 2014, AEH was committed to purchase 100.5 Bcf within one year, 15.9 Bcf within one to three years and 0.8 Bcf after three years under indexed contracts. AEH is committed to purchase 9.5 Bcf within one year and 0.8 Bcf within one to three years under fixed price contracts with prices ranging from $3.75 to $6.36 per Mcf. Purchases under these contracts totaled $621.1 million and $327.8 million for the three months ended March 31, 2014 and 2013 and $971.3 million and $617.3 million for the six months ended March 31, 2014 and 2013.

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 six months ended March 31, 2014.

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 March 31, 2014, rate cases were in progress in our Kansas, Kentucky, Virginia and West Texas service areas, annual rate filing mechanisms were in progress in Louisiana and Mid-Tex and infrastructure program filings were in progress in Mid-Tex and Atmos Pipeline–Texas. 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 six months ended March 31, 2014 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 hedged approximately 32 percent, or 24.6 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

The costs associated with 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 49 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 effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

As of March 31, 2014, we had forward starting interest rate swaps to effectively 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, at 3.129% and 3.37%, which we designated as cash flow hedges at the time the agreements were executed. In April and May 2014, we entered into forward starting interest rate swaps to effectively fix the Treasury yield component associated with $250 million of the anticipated issuance of $450 million unsecured senior notes in fiscal 2019 at 3.95%, 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 March 31, 2014, 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 March 31, 2014, 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 March 31, 2014, 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	—	(5,770)
	Cash Flow	—	21,795
	Not designated	8,428	45,975
		8,428	62,000

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 March 31, 2014 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)			
March 31, 2014					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 11,398	$ (6,849)
Interest rate contracts	Other current assets / Other current liabilities	54,093	—	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	557	(944)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	30,665	—	—	—
Total		84,758	—	11,955	(7,793)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	4,653	—	48,402	(56,065)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	34,017	(24,720)
Total..		4,653	—	82,419	(80,785)
Gross Financial Instruments		89,411	—	94,374	(88,578)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting..........................		—	—	(85,464)	85,464
Net Financial Instruments		89,411	—	8,910	(3,114)
Cash collateral............................		—	—	7,940	3,114
Net Assets/Liabilities from Risk Management Activities...............		$ 89,411	$ —	$ 16,850	$ —

	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 March 31, 2014 and 2013 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(3.7) million and $1.7 million. For the six months ended March 31, 2014 and 2013, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $1.4 million and $17.8 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2014 and 2013 is presented below.

	Three Months Ended March 31 2014	Three Months Ended March 31 2013
	(In thousands)	
Commodity contracts	$ 3,587	$ (17,846)
Fair value adjustment for natural gas inventory designated as the hedged item	(7,450)	19,586
Total (increase) decrease in purchased gas cost	$ (3,863)	$ 1,740
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (579)	$ 1,458
Timing ineffectiveness	(3,284)	282
	$ (3,863)	$ 1,740

	Six Months Ended March 31	
	2014	2013
	(In thousands)	
Commodity contracts	$ (4,974)	$ (10,532)
Fair value adjustment for natural gas inventory designated as the hedged item	6,329	28,405
Total decrease in purchased gas cost	$ 1,355	$ 17,873
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (1,199)	$ 1,218
Timing ineffectiveness	2,554	16,655
	$ 1,355	$ 17,873

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 and six months ended March 31, 2014 and 2013 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 March 31, 2014		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 7,184	$ 7,184
Gain arising from ineffective portion of commodity contracts	—	142	142
Total impact on purchased gas cost	—	7,326	7,326
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,057)	—	(1,057)
Total Impact from Cash Flow Hedges	$ (1,057)	$ 7,326	$ 6,269

	Three Months Ended March 31, 2013		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (5,199)	$ (5,199)
Loss arising from ineffective portion of commodity contracts	—	(83)	(83)
Total impact on purchased gas cost	—	(5,282)	(5,282)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(873)	—	(873)
Total Impact from Cash Flow Hedges	$ (873)	$ (5,282)	$ (6,155)

	Six Months Ended March 31, 2014		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts...	$ —	$ 4,574	$ 4,574
Gain arising from ineffective portion of commodity contracts	—	24	24
Total impact on purchased gas cost	—	4,598	4,598
Loss on settled interest rate agreements reclassified from AOCI into interest expense	(2,115)	—	(2,115)
Total Impact from Cash Flow Hedges	$ (2,115)	$ 4,598	$ 2,483

	Six Months Ended March 31, 2013		
	Natural Gas Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts...	$ —	$ (10,359)	$ (10,359)
Loss arising from ineffective portion of commodity contracts	—	(102)	(102)
Total impact on purchased gas cost	—	(10,461)	(10,461)
Loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,375)	—	(1,375)
Total Impact from Cash Flow Hedges	$ (1,375)	$ (10,461)	$ (11,836)

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 and six months ended March 31, 2014 and 2013. 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 March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$ (27,718)	$ 22,955	$ (14,448)	$ 34,900
Forward commodity contracts	5,483	5,666	11,709	2,153
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	671	554	1,343	873
Forward commodity contracts	(4,382)	3,172	(2,790)	6,320
Total other comprehensive income (loss) from hedging, net of tax[1]	$ (25,946)	$ 32,347	$ (4,186)	$ 44,246

[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 March 31, 2014. 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	$ (1,830)	$ 4,682	$ 2,852
Thereafter	(27,191)	(239)	(27,430)
Total[(1)]	$ (29,021)	$ 4,443	$ (24,578)

(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 March 31, 2014 and 2013 was an increase (decrease) in gross profit of $(9.3) million and $6.8 million. For the six months ended March 31, 2014 and 2013 gross profit increased (decreased) by $(10.1) million and $6.7 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	2,369	(14,448)	11,709	(370)
Amounts reclassified from accumulated other comprehensive income	(227)	1,343	(2,790)	(1,674)
Net current-period other comprehensive income	2,142	(13,105)	8,919	(2,044)
March 31, 2014	$ 7,590	$ 24,801	$ 4,443	$ 36,834

	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	1,135	34,900	2,153	38,188
Amounts reclassified from accumulated other comprehensive income	(1,708)	873	6,320	5,485
Net current-period other comprehensive income	(573)	35,773	8,473	43,673
March 31, 2013	$ 5,088	$ (8,500)	$ (522)	$ (3,934)

The following tables detail reclassifications out of AOCI for the three and six months ended March 31, 2014 and 2013. Amounts in parentheses below indicate decreases to net income in the statement of income.

Accumulated Other Comprehensive Income Components	Three Months Ended March 31, 2014 Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 358	Operation and maintenance expense
	358	Total before tax
	(131)	Tax expense
	$ 227	Net of tax
Cash flow hedges		
Interest rate agreements	$ (1,057)	Interest charges
Commodity contracts	7,184	Purchased gas cost
	6,127	Total before tax
	(2,416)	Tax expense
	$ 3,711	Net of tax
Total reclassifications	$ 3,938	Net of tax

Accumulated Other Comprehensive Income Components	Three Months Ended March 31, 2013 Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 2,689	Operation and maintenance expense
	2,689	Total before tax
	(981)	Tax expense
	$ 1,708	Net of tax
Cash flow hedges		
Interest rate agreements	$ (873)	Interest charges
Commodity contracts	(5,201)	Purchased gas cost
	(6,074)	Total before tax
	2,348	Tax benefit
	$ (3,726)	Net of tax
Total reclassifications	$ (2,018)	Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2014	
	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 358	Operation and maintenance expense
	358	Total before tax
	(131)	Tax expense
	$ 227	Net of tax
Cash flow hedges		
Interest rate agreements	$ (2,115)	Interest charges
Commodity contracts	4,574	Purchased gas cost
	2,459	Total before tax
	(1,012)	Tax expense
	$ 1,447	Net of tax
Total reclassifications	$ 1,674	Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2013	
	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 2,689	Operation and maintenance expense
	2,689	Total before tax
	(981)	Tax expense
	$ 1,708	Net of tax
Cash flow hedges		
Interest rate agreements	$ (1,375)	Interest charges
Commodity contracts	(10,361)	Purchased gas cost
	(11,736)	Total before tax
	4,543	Tax benefit
	$ (7,193)	Net of tax
Total reclassifications	$ (5,485)	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 six months ended March 31, 2014, 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 March 31, 2014 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)	March 31, 2014
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 89,411	$ —	$ —	$ 89,411
Nonregulated segment	89	94,285	—	(77,524)	16,850
Total financial instruments	89	183,696	—	(77,524)	106,261
Hedged portion of gas stored underground	23,570	—	—	—	23,570
Available-for-sale securities					
Money market funds	—	2,904	—	—	2,904
Registered investment companies	44,263	—	—	—	44,263
Bonds	—	28,503	—	—	28,503
Total available-for-sale securities	44,263	31,407	—	—	75,670
Total assets	$ 67,922	$ 215,103	$ —	$ (77,524)	$ 205,501
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ —	$ —	$ —	$ —
Nonregulated segment	1,297	87,281	—	(88,578)	—
Total liabilities	$ 1,297	$ 87,281	$ —	$ (88,578)	$ —

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2013
			(In thousands)		
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 March 31, 2014, we had $11.1 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $3.1 million was used to offset current risk management liabilities under master netting arrangements and the remaining $8.0 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 March 31, 2014								
Domestic equity mutual funds	$	27,226	$	10,052	$	—	$	37,278
Foreign equity mutual funds		5,118		1,867		—		6,985
Bonds		28,320		191		(8)		28,503
Money market funds		2,904		—		—		2,904
	$	63,568	$	12,110	$	(8)	$	75,670
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 March 31, 2014 and September 30, 2013, our available-for-sale securities included $47.2 million and $44.5 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At March 31, 2014, we maintained investments in bonds that have contractual maturity dates ranging from April 2014 through July 2017. During the six months ended March 31, 2013, we recognized a gain of $2.7 million on the sale of certain assets in the rabbi trusts.

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 March 31, 2014 and September 30, 2013:

		March 31, 2014		September 30, 2013
		(In thousands)		
Carrying Amount	$	2,460,000	$	2,460,000
Fair Value	$	2,739,091	$	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 six months ended March 31, 2014, 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 and six months ended March 31, 2013, 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 March 31, 2014 and September 30, 2013 we did not have any assets or liabilities held for sale.

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Operating revenues	$ —	$ 21,678	$ —	$ 37,962
Purchased gas cost	—	12,497	—	21,464
Gross profit	—	9,181	—	16,498
Operating expenses	—	3,038	—	5,858
Operating income	—	6,143	—	10,640
Other nonoperating income	—	200	—	548
Income from discontinued operations before income taxes	—	6,343	—	11,188
Income tax expense	—	2,258	—	3,986
Net income from discontinued operations	$ —	$ 4,085	$ —	$ 7,202

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 March 31, 2014, the related condensed consolidated statements of income and comprehensive income for the three and six-month periods ended March 31, 2014 and 2013, and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2014 and 2013. 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
May 7, 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", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; 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 March 31, 2014 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.

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 six months ended March 31, 2014.

RESULTS OF OPERATIONS

Executive Summary

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.

Consolidated income from continuing operations for the six months ended March 31, 2014 increased 16 percent period over period as a result of positive rate outcomes combined with increased gross profit associated with weather that was 25 percent colder than the prior-year period. Combined rate increases received in our regulated segments increased gross profit by $29.4 million. As of March 31, 2014, we had completed seven regulatory proceedings in our regulated segments resulting in an $18.2 million increase in annual operating income and had nine ratemaking efforts in progress seeking $124.1 million of additional annual operating income.

Our consolidated results were also favorably impacted by the significantly colder than normal weather experienced during the first six months of our fiscal year. Regulated gross profit increased $18.9 million due to increased customer consumption in our natural gas distribution segment and increased throughput and related margins in our regulated transportation segment associated with colder weather. The colder than normal weather also increased market demand for natural gas, which drove higher price volatility, particularly during our second fiscal quarter. As a result, realized gross margin in our nonregulated operations increased $22.6 million period over period from trading gains primarily captured during the second fiscal quarter.

During the first six months of fiscal 2014, our capital expenditures were $359.0 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 and debt and equity securities, while maintaining a balanced capital structure.

On February 18, 2014, we completed the sale of 9,200,000 shares of common stock, including the underwriters' exercise of their overallotment option of 1,200,000 shares, under our shelf registration statement, generating net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

Our debt-to-capitalization ratio as of March 31, 2014 was 44 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 effectively 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 in the first quarter of fiscal 2014.

Consolidated Results

The following table presents our consolidated financial highlights for the three and six months ended March 31, 2014 and 2013:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands, except per share data)			
Operating revenues	$ 1,964,322	$ 1,308,996	$ 3,219,470	$ 2,343,151
Gross profit	496,277	432,751	885,234	795,113
Operating expenses	246,197	222,573	464,434	430,013
Operating income	250,080	210,178	420,800	365,100
Miscellaneous income (expense)	(1,516)	1,712	(3,648)	2,410
Interest charges	31,601	33,331	63,716	63,853
Income from continuing operations before income taxes	216,963	178,559	353,436	303,657
Income tax expense	83,596	66,219	133,053	113,969
Income from continuing operations	133,367	112,340	220,383	189,688
Income from discontinued operations, net of tax	—	4,085	—	7,202
Net income	$ 133,367	$ 116,425	$ 220,383	$ 196,890
Diluted net income per share from continuing operations	$ 1.38	$ 1.23	$ 2.34	$ 2.07
Diluted net income per share from discontinued operations	—	0.04	—	0.08
Diluted net income per share	$ 1.38	$ 1.27	$ 2.34	$ 2.15

Our consolidated net income during the three and six month periods ended March 31, 2014 and 2013 was earned in each of our business segments as follows:

	Three Months Ended March 31		
	2014	2013	Change
		(In thousands)	
Natural gas distribution segment from continuing operations	$ 88,743	$ 86,190	$ 2,553
Regulated transmission and storage segment	24,109	16,530	7,579
Nonregulated segment	20,515	9,620	10,895
Net income from continuing operations	133,367	112,340	21,027
Net income from discontinued operations	—	4,085	(4,085)
Net income	$ 133,367	$ 116,425	$ 16,942

	Six Months Ended March 31		
	2014	2013	Change
		(In thousands)	
Natural gas distribution segment from continuing operations	$ 151,500	$ 139,283	$ 12,217
Regulated transmission and storage segment	43,555	32,635	10,920
Nonregulated segment	25,328	17,770	7,558
Net income from continuing operations	220,383	189,688	30,695
Net income from discontinued operations	—	7,202	(7,202)
Net income	$ 220,383	$ 196,890	$ 23,493

Regulated operations contributed 85 percent and 89 percent to our consolidated net income for the three and six months ended March 31, 2014. 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 March 31		
	2014	2013	Change
	(In thousands, except per share data)		
Regulated operations	$ 112,852	$ 102,720	$ 10,132
Nonregulated operations	20,515	9,620	10,895
Net income from continuing operations	133,367	112,340	21,027
Net income from discontinued operations	—	4,085	(4,085)
Net income	$ 133,367	$ 116,425	$ 16,942
Diluted EPS from continuing regulated operations	$ 1.17	$ 1.12	$ 0.05
Diluted EPS from nonregulated operations	0.21	0.11	0.10
Diluted EPS from continuing operations	1.38	1.23	0.15
Diluted EPS from discontinued operations	—	0.04	(0.04)
Consolidated diluted EPS	$ 1.38	$ 1.27	$ 0.11

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, except per share data)		
Regulated operations	$ 195,055	171,918	$ 23,137
Nonregulated operations	25,328	17,770	7,558
Net income from continuing operations	220,383	189,688	30,695
Net income from discontinued operations	—	7,202	(7,202)
Net income	$ 220,383	$ 196,890	$ 23,493
Diluted EPS from continuing regulated operations	$ 2.07	$ 1.87	$ 0.20
Diluted EPS from nonregulated operations	0.27	0.20	0.07
Diluted EPS from continuing operations	2.34	2.07	0.27
Diluted EPS from discontinued operations	—	0.08	(0.08)
Consolidated diluted EPS	$ 2.34	$ 2.15	$ 0.19

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 March 31, 2014 compared with Three Months Ended March 31, 2013

Financial and operational highlights for our natural gas distribution segment for the three months ended March 31, 2014 and 2013 are presented below.

	Three Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 385,188	$ 347,006	$ 38,182
Operating expenses	217,402	186,567	30,835
Operating income	167,786	160,439	7,347
Miscellaneous income	97	2,591	(2,494)
Interest charges	22,828	25,664	(2,836)
Income from continuing operations before income taxes	145,055	137,366	7,689
Income tax expense	56,312	51,176	5,136
Income from continuing operations	88,743	86,190	2,553
Income from discontinued operations, net of tax	—	4,085	(4,085)
Net income	$ 88,743	$ 90,275	$ (1,532)
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	151,083	120,123	30,960
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	40,404	36,540	3,864
Consolidated natural gas distribution throughput from continuing operations — MMcf	191,487	156,663	34,824
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	2,674	(2,674)
Total consolidated natural gas distribution throughput — MMcf	191,487	159,337	32,150
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	$ 6.00	$ 4.67	$ 1.33

Income from continuing operations for our natural gas distribution segment increased three percent, primarily due to a $38.2 million increase in gross profit, partially offset by a $30.8 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $13.2 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky and Louisiana service areas.
- a $4.9 million increase due to increased customer consumption resulting from colder weather, primarily experienced in our West Texas, Kentucky/Mid-States and Mississippi Divisions.
- a $2.1 million increase in service order revenue.
- a $12.9 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $10.3 million increase in the related tax expense.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased levels and timing of incentive compensation expense resulting from improved operating results, increased labor costs primarily associated with increased standby and overtime costs and lower labor capitalization rates as employees incurred more time compared to the prior year period to ensure our distribution system was safe and reliable during the colder than normal weather.

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 March 31, 2014 and 2013. 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 March 31		
	2014	2013	Change
		(In thousands)	
Mid-Tex	$ 67,805	$ 59,713	$ 8,092
Kentucky/Mid-States	29,422	24,497	4,925
Louisiana	25,992	24,004	1,988
West Texas	15,764	15,008	756
Mississippi	20,559	19,825	734
Colorado-Kansas	16,603	16,677	(74)
Other	(8,359)	715	(9,074)
Total	$ 167,786	$ 160,439	$ 7,347

Six Months Ended March 31, 2014 compared with Six Months Ended March 31, 2013

Financial and operational highlights for our natural gas distribution segment for the six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 684,359	$ 626,637	$ 57,722
Operating expenses	393,700	357,114	36,586
Operating income	290,659	269,523	21,136
Miscellaneous income (expense)	(374)	2,460	(2,834)
Interest charges	46,153	49,227	(3,074)
Income from continuing operations before income taxes	244,132	222,756	21,376
Income tax expense	92,632	83,473	9,159
Income from continuing operations	151,500	139,283	12,217
Income from discontinued operations, net of tax	—	7,202	(7,202)
Net income	$ 151,500	$ 146,485	$ 5,015
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	249,361	198,876	50,485
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	72,611	69,429	3,182
Consolidated natural gas distribution throughput from continuing operations — MMcf	321,972	268,305	53,667
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	4,731	(4,731)
Total consolidated natural gas distribution throughput — MMcf	321,972	273,036	48,936
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.48	$ 0.46	$ 0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.82	$ 4.77	$ 1.05

Income from continuing operations for our natural gas distribution segment increased nine percent, primarily due to a $57.7 million increase in gross profit, partially offset by a $36.6 million increase in operating expenses. The year to date increase in gross profit primarily reflects:

- a $15.9 million increase due to increased customer consumption resulting from colder weather, primarily experienced in our Mid-Tex, West Texas, Colorado-Kansas and Kentucky/Mid-State Divisions.
- a $15.3 million net increase in rate adjustments, primarily in our Mid-Tex, Kentucky, Louisiana and Tennessee service areas.
- a $17.8 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $14.3 million increase in the related tax expense.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased levels and timing of incentive compensation expense resulting from improved operating results, increased labor costs primarily associated with increased standby and overtime costs and lower labor capitalization rates as employees incurred more time compared to the prior year period to ensure our distribution system was safe and reliable during the colder than normal weather.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the six months ended March 31, 2014 and 2013. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands)		
Mid-Tex	$ 124,909	$ 105,290	$ 19,619
Kentucky/Mid-States	47,519	40,202	7,317
Louisiana	43,418	40,889	2,529
West Texas	23,806	24,586	(780)
Mississippi	32,977	31,438	1,539
Colorado-Kansas	25,416	25,421	(5)
Other	(7,386)	1,697	(9,083)
Total	$ 290,659	$ 269,523	$ 21,136

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 six months of fiscal 2014, we completed seven regulatory proceedings, resulting in an $18.2 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Infrastructure programs	$ 4,353
Annual rate filing mechanisms	12,497
Rate case filings	1,609
Other rate activity	(226)
	$ 18,233

Additionally, the following ratemaking efforts seeking $78.5 million in annual operating income were in progress as of March 31, 2014:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Rate Case	Kansas	$ 7,005
Kentucky/Mid-States	Rate Case[1]	Kentucky	13,133
Kentucky/Mid-States	Rate Case	Virginia	2,128
Louisiana	Rate Stabilization Clause[2]	Trans LA	550
Mid-Tex	Dallas Annual Rate Review	Dallas	7,934
Mid-Tex	Rate Review Mechanism	Mid-Tex Cities	34,874
Mid-Tex	GRIP	Mid-Tex Environs	881
West Texas	Rate Case[3]	West Texas	12,032
			$ 78,537

(1) 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. The Kentucky commission issued a final order on April 2, 2014 authorizing an increase of $5.8 million.

(2) The Trans LA rate stabilization clause operating income increase of $0.6 million was implemented on April 1, 2014.

(3) The West Texas rate case operating income increase of $8.4 million was implemented on April 1, 2014. The West Texas Cities portion of the division also agreed to reestablish the annual rate review mechanism process. The cities of Amarillo, Channing, Dalhart and Lubbock agreed to annual GRIP filings.

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 March 31, 2014, 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 six months ended March 31, 2014.

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
Colorado-Kansas - Kansas	09/2013	9,323	882	02/01/2014
Total 2014 Infrastructure Programs		$ 1,502,346	$ 4,353	

(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 March 31, 2014 we had annual rate filing mechanisms in our Louisiana and Mississippi service areas and in our Texas divisions. These mechanisms are referred to as the Dallas annual rate review (DARR) and rate review mechanism (RRM) in our Mid-Tex and West Texas Divisions, stable rate filings in the Mississippi Division and rate stabilization clause in the Louisiana Division. The following annual rate filing mechanisms were completed during the six months ended March 31, 2014.

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

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate cases that were completed during the six months ended March 31, 2014.

Division	State	Increase in Annual Operating Income (In thousands)	Effective Date
2014 Rate Case Filings:			
Colorado-Kansas	Colorado	$ 1,609	03/01/2014
Total 2014 Rate Case Filings		$ 1,609	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2014.

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2014 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem[(1)]	$ (226)	02/01/2014
Total 2014 Other Rate Activity.............................			$ (226)	

[(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.

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 March 31, 2014 compared with Three Months Ended March 31, 2013

Financial and operational highlights for our regulated transmission and storage segment for the three months ended March 31, 2014 and 2013 are presented below.

	Three Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 50,761	$ 42,947	$ 7,814
Third-party transportation	18,885	14,769	4,116
Storage and park and lend services	1,429	1,562	(133)
Other	2,540	2,570	(30)
Gross profit	73,615	61,848	11,767
Operating expenses	25,519	28,357	(2,838)
Operating income	48,096	33,491	14,605
Miscellaneous expense	(1,081)	(99)	(982)
Interest charges	9,155	7,857	1,298
Income before income taxes	37,860	25,535	12,325
Income tax expense	13,751	9,005	4,746
Net income	$ 24,109	$ 16,530	$ 7,579
Gross pipeline transportation volumes — MMcf	210,610	179,021	31,589
Consolidated pipeline transportation volumes — MMcf	115,830	105,099	10,731

Net income for our regulated transmission and storage segment increased 46 percent, primarily due to an $11.8 million increase in gross profit, combined with a $2.8 million decrease in operating expenses. The increase in gross profit primarily reflects a $7.3 million increase in rates from the approved 2013 GRIP filing coupled with a $1.4 million increase associated with higher throughput and basis spreads driven by colder weather.

Operating expenses decreased $2.8 million primarily due to a $6.7 million refund received as a result of the completion of a state use tax audit. The refund was partially offset by increased depreciation expense associated with increased capital investments and employee-related expenses.

On May 6, 2014, a GRIP filing was approved by the RRC for $45.6 million of additional annual operating income.

Six Months Ended March 31, 2014 compared with Six Months Ended March 31, 2013

Financial and operational highlights for our regulated transmission and storage segment for the six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 100,505	$ 83,732	$ 16,773
Third-party transportation	36,044	29,318	6,726
Storage and park and lend services	3,250	3,072	178
Other	5,157	6,407	(1,250)
Gross profit	144,956	122,529	22,427
Operating expenses	57,268	57,016	252
Operating income	87,688	65,513	22,175
Miscellaneous expense	(2,262)	(226)	(2,036)
Interest charges	18,112	14,728	3,384
Income before income taxes	67,314	50,559	16,755
Income tax expense	23,759	17,924	5,835
Net income	$ 43,555	$ 32,635	$ 10,920
Gross pipeline transportation volumes — MMcf	399,786	340,505	59,281
Consolidated pipeline transportation volumes — MMcf	234,604	213,842	20,762

Net income for our regulated transmission and storage segment increased 33 percent, primarily due to a $22.4 million increase in gross profit. The increase in gross profit primarily reflects a $14.1 million increase in rates from the approved 2013 GRIP filing coupled with a $3.0 million increase associated with higher throughput and basis spreads driven by colder weather.

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.

Operating expenses increased $0.3 million primarily due to increased depreciation expense associated with increased capital investments and employee-related expenses, partially offset by the aforementioned state use tax refund.

Nonregulated Segment

Our nonregulated operations are conducted through Atmos Energy Holdings, Inc. (AEH), a wholly-owned subsidiary of Atmos Energy Corporation and, for the fiscal year ended September 30, 2013, represented 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 March 31, 2014 compared with Three Months Ended March 31, 2013

Financial and operating highlights for our nonregulated segment for the three months ended March 31, 2014 and 2013 are presented below.

	Three Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 12,449	$ 15,264	$ (2,815)
Storage and transportation services	3,677	3,596	81
Other	19,829	2,806	17,023
Total realized margins	35,955	21,666	14,289
Unrealized margins	1,634	2,641	(1,007)
Gross profit	37,589	24,307	13,282
Operating expenses	3,391	8,060	(4,669)
Operating income	34,198	16,247	17,951
Miscellaneous income (expense)	443	(91)	534
Interest charges	593	498	95
Income before income taxes	34,048	15,658	18,390
Income tax expense	13,533	6,038	7,495
Net income	$ 20,515	$ 9,620	$ 10,895
Gross nonregulated delivered gas sales volumes — MMcf	139,753	109,723	30,030
Consolidated nonregulated delivered gas sales volumes — MMcf	119,967	97,732	22,235
Net physical position (Bcf)	1.9	20.8	(18.9)

The $13.3 million quarter-over-quarter increase in gross profit reflected a $14.3 million increase in realized margins, offset by a $1.0 million decrease in unrealized margins. The $14.3 million increase in realized margins reflects:

- A $17.0 million increase in realized margins due to the acceleration of physical withdrawals into the second quarter to capture gross profit margin during periods of increased natural gas price volatility caused by strong market demand as a result of significantly colder weather during the current quarter compared with the prior-year quarter.
- A $2.8 million decrease in gas delivery and related services margins. Consolidated sales volumes increased twenty-three percent as a result of stronger demand from marketing, industrial and utility/municipal customers due to colder weather. The increases in volume were offset by lower gas delivery per-unit margins which decreased from 14 cents per Mcf in the prior-year quarter to 9 cents, which reflects losses incurred to meet peaking requirements for certain

customers during periods of colder weather, due to volatility between spot purchase prices and the contractual sales price to the customer.

Unrealized margins decreased $1.0 million primarily due to the quarter-over-quarter timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses decreased $4.7 million, primarily due to lower legal expense related to the dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 7 to the financial statements.

Six Months Ended March 31, 2014 compared with Six Months Ended March 31, 2013

Financial and operating highlights for our nonregulated segment for the six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 24,912	$ 25,334	$ (422)
Storage and transportation services	7,212	7,117	95
Other	11,827	(11,304)	23,131
Total realized margins	43,951	21,147	22,804
Unrealized margins	12,204	25,619	(13,415)
Gross profit	56,155	46,766	9,389
Operating expenses	13,702	16,705	(3,003)
Operating income	42,453	30,061	12,392
Miscellaneous income	767	1,576	(809)
Interest charges	1,230	1,295	(65)
Income before income taxes	41,990	30,342	11,648
Income tax expense	16,662	12,572	4,090
Net income	$ 25,328	$ 17,770	$ 7,558
Gross nonregulated delivered gas sales volumes — MMcf	247,332	208,732	38,600
Consolidated nonregulated delivered gas sales volumes — MMcf	212,604	182,450	30,154
Net physical position (Bcf)	1.9	20.8	(18.9)

Net income for our nonregulated segment increased 43 percent from the prior year due to higher gross profit and decreased operating expenses.

The $9.4 million period-over-period increase in gross profit reflected a $22.8 million increase in realized margins, offset by a $13.4 million decrease in unrealized margins. The $22.8 million increase in realized margins reflects:

- A $23.1 million increase in other realized margins due to the aforementioned storage optimization gains earned during the second quarter. In contrast, losses were incurred from storage optimization activities in the prior year largely due to unfavorable changes in market prices relative to the execution strategy in place at that time.
- A $0.4 million decrease in gas delivery and related services margins. Consolidated sales volumes increased seventeen percent as a result of stronger demand from marketing, industrial and utility/municipal customers due to colder weather. Additionally, gas delivery per-unit margins decreased from 12 cents per Mcf in the prior-year period to 10 cents per Mcf due primarily to losses incurred during the second quarter to meet peaking requirements for certain customers during periods of colder weather, due to volatility between spot purchase prices and the contractual sales price to the customer.

Unrealized margins decreased $13.4 million primarily due to the period-over-period timing of realized margins on the settlement of hedged natural gas inventory positions.

Operating expenses decreased $3.0 million, primarily due to lower legal expense related to the dismissal of the Kentucky litigation and the resolution of the Tennessee Business License Tax matter, which are discussed in Note 7 to the financial statements.

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. To support our capital market activities, we have a shelf registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. On February18, 2014, we completed the public offering of 9,200,000 shares of our common stock including the underwriters' exercise of their overallotment option of 1,200,000 shares. The offering was priced at $44.00 and generated net proceeds of $390.2 million, which were used to repay short-term debt outstanding under our $950 million commercial paper program, to fund infrastructure spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

As of March 31, 2014, $1.35 billion of securities remained available for issuance under the shelf registration statement until March 28, 2016.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2014, September 30, 2013 and March 31, 2013:

	March 31, 2014		September 30, 2013		March 31, 2013	
			(In thousands, except percentages)			
Short-term debt	$ —	—%	$ 367,984	6.8%	$ 232,998	4.5%
Long-term debt[1]	2,455,829	44.0%	2,455,671	45.4%	2,455,514	46.9%
Shareholders' equity	3,124,761	56.0%	2,580,409	47.8%	2,543,470	48.6%
Total	$ 5,580,590	100.0%	$ 5,404,064	100.0%	$ 5,231,982	100.0%

(1) 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 effectively 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 44 percent at March 31, 2014, 52.2 percent at September 30, 2013 and 51.4 percent at March 31, 2013.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, 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 six months ended March 31, 2014 and 2013 are presented below.

	Six Months Ended March 31		
	2014	2013	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 490,981	$ 376,341	$ 114,640
Investing activities	(363,913)	(392,817)	28,904
Financing activities	(56,527)	17,784	(74,311)
Change in cash and cash equivalents	70,541	1,308	69,233
Cash and cash equivalents at beginning of period	66,199	64,239	1,960
Cash and cash equivalents at end of period	$ 136,740	$ 65,547	$ 71,193

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 changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the six months ended March 31, 2014, we generated cash flow of $491.0 million from operating activities compared with $376.3 million for the six months ended March 31, 2013. The $114.6 million increase in operating cash flows primarily reflects higher operating results from colder weather and rate increases combined with the timing of customer collections and vendor payments.

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 six months ended March 31, 2014, capital expenditures were $359.0 million, compared with $389.1 million in the prior-year period. The period-over-period decrease primarily reflects:

- A $19.1 million decrease in capital spending in our regulated transmission and storage segment associated with the completion of the Line WX expansion project, partially offset by increased cathodic protection spending.
- A $10.3 million decrease in capital spending in our natural gas distribution segment due to the timing of spending under our infrastructure replacement programs and the absence of spending related to our new customer information system, which was completed in the prior year.

Cash flows from financing activities

For the six months ended March 31, 2014, our financing activities used $56.5 million of cash compared with $17.8 million generated in the prior-year period. The decrease is primarily due to timing between short-term debt borrowings and repayments during the current year partially offset by proceeds from the equity offering completed in February 2014 compared with proceeds generated from the issuance of long-term debt in the prior-year period.

The following table summarizes our share issuances for the six months ended March 31, 2014 and 2013.

	Six Months Ended March 31	
	2014	2013
Shares issued:		
1998 Long-Term Incentive Plan	479,521	385,020
Outside Directors Stock-for-Fee Plan	922	1,125
February 2014 Offering	9,200,000	—
Total shares issued	9,680,443	386,145

The year-over-year increase in the number of shares issued primarily reflects the equity offering completed in February 2014 as well as a higher number of performance-based awards issued in the current year as actual performance exceeded the target. For the six months ended March 31, 2014 and 2013, we canceled and retired 142,829 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 billion of working capital funding. As of March 31, 2014, the amount available to us under our credit facilities, net of outstanding letters of credit, was $1,012.8 million.

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 March 31, 2014, 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
Senior unsecured long-term debt	A-	A2	A-
Commercial paper	A-2	P-1	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 March 31, 2014. 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 six months ended March 31, 2014.

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 and six months ended March 31, 2014 and 2013:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Fair value of contracts at beginning of period	$ 134,776	$ (64,197)	$ 109,648	$ (76,260)
Contracts realized/settled	6,868	(306)	5,197	2,529
Fair value of new contracts	347	683	866	1,013
Other changes in value	(52,580)	103,946	(26,300)	112,844
Fair value of contracts at end of period	$ 89,411	$ 40,126	$ 89,411	$ 40,126

The fair value of our natural gas distribution segment's financial instruments at March 31, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2014				
	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	$ 58,746	$ 30,665	$ —	$ —	$ 89,411
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ 58,746	$ 30,665	$ —	$ —	$ 89,411

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and six months ended March 31, 2014 and 2013:

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
	(In thousands)			
Fair value of contracts at beginning of period	$ (5,093)	$ (1,562)	$ (14,700)	$ (15,123)
Contracts realized/settled	4,635	(492)	14,578	12,244
Fair value of new contracts	—	—	—	—
Other changes in value	6,254	(1,965)	5,918	(1,140)
Fair value of contracts at end of period	5,796	(4,019)	5,796	(4,019)
Netting of cash collateral	11,054	11,971	11,054	11,971
Cash collateral and fair value of contracts at period end	$ 16,850	$ 7,952	$ 16,850	$ 7,952

The fair value of our nonregulated segment's financial instruments at March 31, 2014 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2014				
	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	$ (3,114)	$ 9,068	$ (158)	$ —	$ 5,796
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (3,114)	$ 9,068	$ (158)	$ —	$ 5,796

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2014 and 2013, our total net periodic pension and other benefits costs were $37.2 million and $37.8 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 six months ended March 31, 2014 we contributed $9.1 million to our defined benefit plans. Based upon the most recent evaluation, we anticipate contributing a total of between $10 million and $35 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 six months ended March 31, 2014 we contributed $11.6 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 and six month periods ended March 31, 2014 and 2013.

Natural Gas Distribution Sales and Statistical Data — Continuing Operations

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
METERS IN SERVICE, end of period				
Residential	2,777,135	2,816,734	2,777,135	2,816,734
Commercial	250,144	256,955	250,144	256,955
Industrial	1,495	2,127	1,495	2,127
Public authority and other	8,797	10,268	8,797	10,268
Total meters	3,037,571	3,086,084	3,037,571	3,086,084
INVENTORY STORAGE BALANCE — Bcf[1]	22.6	28.3	22.6	28.3
SALES VOLUMES — MMcf[2]				
Gas sales volumes				
Residential	95,913	74,929	156,329	121,252
Commercial	45,521	36,465	76,935	61,721
Industrial	5,805	4,928	9,824	9,483
Public authority and other	3,844	3,801	6,273	6,420
Total gas sales volumes	151,083	120,123	249,361	198,876
Transportation volumes	44,319	39,925	79,743	73,947
Total throughput	195,402	160,048	329,104	272,823
OPERATING REVENUES (000's)[2]				
Gas sales revenues				
Residential	$ 843,385	$ 589,180	$ 1,388,802	$ 1,011,901
Commercial	358,907	244,338	594,330	429,269
Industrial	30,797	24,300	54,545	45,756
Public authority and other	27,694	22,470	44,143	38,150
Total gas sales revenues	1,260,783	880,288	2,081,820	1,525,076
Transportation revenues	20,939	17,792	37,756	33,233
Other gas revenues	9,238	7,096	15,249	13,654
Total operating revenues	$ 1,290,960	$ 905,176	$ 2,134,825	$ 1,571,963
Average transportation revenue per Mcf[1]	$ 0.47	$ 0.45	$ 0.47	$ 0.46
Average cost of gas per Mcf sold[1]	$ 6.00	$ 4.67	$ 5.82	$ 4.77

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data — Discontinued Operations

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
Meters in service, end of period	—	64,089	—	64,089
Sales volumes — MMcf				
Total gas sales volumes	—	2,069	—	3,611
Transportation volumes	—	605	—	1,120
Total throughput	—	2,674	—	4,731
Operating revenues (000's)	$ —	$ 21,678	$ —	$ 37,962

Regulated Transmission and Storage and Nonregulated Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2014	2013	2014	2013
CUSTOMERS, end of period				
Industrial	748	772	748	772
Municipal	130	124	130	124
Other	564	437	564	437
Total	1,442	1,333	1,442	1,333
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	9.7	25.2	9.7	25.2
REGULATED TRANSMISSION AND STORAGE VOLUMES — MMcf(2)	210,610	179,021	399,786	340,505
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(2)	139,753	109,723	247,332	208,732
OPERATING REVENUES (000's)(2)				
Regulated transmission and storage	$ 73,615	$ 61,848	$ 144,956	$ 122,529
Nonregulated	757,683	428,948	1,205,404	828,842
Total operating revenues	$ 831,298	$ 490,796	$ 1,350,360	$ 951,371

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 six months ended March 31, 2014, 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 March 31, 2014 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 second 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 six months ended March 31, 2014, 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: May 7, 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.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

☑ **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 ☑ 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 ☑ 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 ☑ 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 ☑

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	September 30, 2013
	(Unaudited)	
	(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.

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

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	September 30, 2013				
			(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

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.

		Natural Gas Distribution		Nonregulated	
	Balance Sheet Location	Assets	Liabilities	Assets	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	$ —

	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)	Significant Other Observable Inputs (Level 2)(1)	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral(3)	September 30, 2013
			(In thousands)		
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", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; 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.

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	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
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 (In thousands, except percentages)		December 31, 2012	
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 (In thousands)	Change
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.

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(q) The independent auditor's annual opinion report, with any written communication from the independent auditor to the utility that indicates the existence of a material weakness in the utility's internal controls;

RESPONSE:

Please see attachment FR_16(7)(q)_Att1 for the independent auditor's reports for fiscal years 2013 and 2014.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, FR_16(7)(q)_Att1 - Independent Auditor Report.pdf, 2 Pages.

Respondent: Jason Schneider

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2013 and 2012, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2013. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2013, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2013, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated November 13, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 13, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2014, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Atmos Energy Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of September 30, 2014 and 2013, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2014 of Atmos Energy Corporation and our report dated November 6, 2014 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 6, 2014

FR 16(7)(r)

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(r) The quarterly reports to the stockholders for the most recent five (5) quarters;

RESPONSE:

Please see the Company's response to FR 16(7)(p).

Respondent: Jason Schneider

FR 16(7)(s)

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(s) The summary of the latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and base period depreciation rates used by major plant accounts. If the required information has been filed in another commission case, a reference to that case's number shall be sufficient;

RESPONSE:

Please see the following exhibits to the direct testimony of Dane Watson, provided in the Company's response to FR 16(7)(a):

Exhibit DAW-2 - Atmos Energy Corporation - Kentucky Properties Depreciation Rate Study at September 30, 2014;

Exhibit DAW-3 - Atmos Energy Corporation - Kentucky Mid-States General Office Property Depreciation Rate Study at September 30, 2014; and

Exhibit DAW-4 - Atmos Energy Corporation Shared Services Unit Depreciation Rate Study at September 30, 2014.

Respondent: Dane Watson

FR 16(7)(t)

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(t) A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include:

1. Each software, program, or model;
2. What the software, program, or model was used for;
3. The supplier of each software, program, or model;
4. A brief description of the software, program, or model; and
5. The specifications for the computer hardware and the operating system required to run the program;

RESPONSE:

Atmos Energy prepared testimony, documents, schedules, slides and work papers presented in this filing using Microsoft Office 2010 products. Computers on which Microsoft Office is installed are running Windows 7. These Dell PCs are IBM compatible and are running processors at speeds no less than 2GHz with 2GB of RAM. The Class Cost of Service Study was prepared by using Microsoft Office 2010.

Respondent: Greg Waller

FR 16(7)(u)

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(u) If the utility had amounts charged or allocated to it by an affiliate or a general or home office or paid monies to an affiliate or a general or home office during the base period or during the previous three (3) calendar years, the utility shall file:

1. A detailed description of the method and amounts allocated or charged to the utility by the affiliate or general or home office for each allocation or payment;
2. The method and amounts allocated during the base period and the method and estimated amounts to be allocated during the forecasted test period;
3. An explanation of how the allocator for both the base period and the forecasted test period were determined; and
4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated, or paid during the base period is reasonable;

RESPONSE:

1) The allocation of costs are fully described in the Company's Cost Allocation Manual as filed with this Commission, the latest of which is attached as Exhibit JLS-1 to the Direct Testimony of Jason Schneider. Please see Exhibit GKW-1 to the Direct Testimony of Greg Waller, which provides the composite factors used to allocate costs and rate base items in this rate proceeding.

2) Please see Schedules C.2.1 of FR 16(8)(c), account 922.

3) Please see the response to subpart (1).

4) Please see the response to subpart (1).

Respondent: Jason Schneider

FR 16(7)(v)

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(v) If the utility provides gas, electric, sewage, or water utility service and has annual gross revenues greater than $5,000,000 in the division for which a rate adjustment is sought, a cost of service study based on a methodology generally accepted within the industry and based on current and reliable data from a single time period; and

RESPONSE:

Please see the Direct Testimony of Paul Raab.

Respondent: Paul Raab

FR 16(7)(w)

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(w) Incumbent local exchange carriers with fewer than 50,000 access lines shall not be required to file cost of service studies, except as specifically directed by the commission. Local exchange carriers with more than 50,000 access lines shall file:

1. A jurisdictional separations study consistent with 47 C.F.R. Part 36; and
2. Service specific cost studies to support the pricing of all services that generate annual revenue greater than $1,000,000 except local exchange access:
   a. Based on current and reliable data from a single time period; and
   b. Using generally recognized fully allocated, embedded, or incremental cost principles.

RESPONSE:

Not applicable.

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(8) Each application seeking a general adjustment in rates supported by a forecasted test period shall include:

(a) A jurisdictional financial summary for both the base period and the forecasted period that details how the utility derived the amount of the requested revenue increase;

RESPONSE:

Please see attachment FR_16(8)(a)_Att1, Schedule A.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, FR_16(8)(a)_Att1 - Schedule A.xlsx, 4 Pages.

Respondent: Greg Waller

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Base Period: Twelve Months Ended February 29, 2016
Forecasted Test Period: Twelve Months Ended May 31, 2017

Schedule	Description	Filing Requirement
A	Summary	FR 16(8)(a)
B	Rate Base	FR 16(8)(b)
C	Operating Income (Revenues & Expenses)	FR 16(8)(c)
D	Adjustments to Operating Income by Account	FR 16(8)(d)
E	Income Tax Calculation	FR 16(8)(e)
F	Rule F Compliance Adjustments	FR 16(8)(f)
G	Payroll Analysis	FR 16(8)(g)
H	Gross Revenue Conversion Factor	FR 16(8)(h)
I	Comparative Income Statements	FR 16(8)(i)
J	Cost of Capital	FR 16(8)(j)
K	Comparative Financial Data	FR 16(8)(k)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Base Period: Twelve Months Ended February 29, 2016
Forecasted Test Period: Twelve Months Ended May 31, 2017

Allocation Factors

		Forecast Period			Base Period		
Line No.	Description	KY/ Md-Sts Division	Kentucky Jurisdiction	Kentucky Composite	KY/ Md-Sts Division	Kentucky Jurisdiction	Kentucky Composite
	Rate Base, Dep. Exp., & Taxes Other						
1	**Shared Services**						
2	General Office (Div 002)	10.71%	49.09%	5.26%	10.71%	49.09%	5.26%
3	Customer Support (Div 012)	10.86%	52.60%	5.71%	10.86%	52.60%	5.71%
4	**Kentucky/Mid-States**						
5	Mid-States General Office (Div 091)	100%	49.09%	49.09%	100%	49.09%	49.09%
6							
7							
8	**Greenville Avenue Data Center**			1.54%			1.54%
9	**Charles K. Vaughan Center**			1.08%			1.08%
10							
11	**Kentucky Composite Tax**			38.90%			
12							
13	**Rate of Return on Equity**			10.50%			
14							
15	**STDRATE**			0.94%			
16							
17	**LTDRATE**			5.90%			

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Base Period: Twelve Months Ended February 29, 2016
Forecasted Test Period: Twelve Months Ended May 31, 2017

Schedule	Description
A	Overall Financial Summary

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2015-00343
Overall Financial Summary
Forecasted Test Period: Twelve Months Ended May 31, 2017

Data:__X____Base Period___X____Forecasted Period
Type of Filing:___X____Original________Updated ________Revised
Workpaper Reference No(s).____________________

FR 16(8)(a)
Schedule A
Witness: Waller

Line No.	Description	Supporting Schedule Reference	Base Jurisdictional Revenue Requirement	Forecasted Jurisdictional Revenue Requirement
	(a)	(b)	(c)	(d)
1	Rate Base	B-1	$ 296,786,302	$ 335,832,639
2	Adjusted Operating Income	C-1	$ 22,059,589	$ 25,262,560
3	Earned Rate of Return (line 2 divided by line 1)	J-1	7.43%	7.52%
4	Required Rate of Return	J-1	7.99%	8.12%
5	Required Operating Income (line 1 times line 4)	C-1	$ 23,713,226	$ 27,269,610
6	Operating Income Deficiency (line 5 minus line 2)	C-1	$ 1,653,637	$ 2,007,050
7	Gross Revenue Conversion Factor	H	1.64812	1.64804
8	**Revenue Deficiency (line 6 times line 7)**		**$ 2,725,391**	**$ 3,307,688**
9	Revenue Increase Requested	C-1		$ 3,307,688
10	Adjusted Operating Revenues	C-1		$ 166,804,655
11	Revenue Requirements (line 9 plus line 10)	C-1		$ 170,112,343