ATMOS ENERGY CORP
Form 10-Q
August 05, 2015

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

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

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

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

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

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

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

Large Accelerated Filer þ Accelerated Filer ¨ Non-Accelerated Filer ¨ Smaller Reporting Company ¨
(Do not check if a smaller reporting company)

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

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

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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.

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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 (In thousands)	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
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.

	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated 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
	(3,172)	—	(3,172)

Net loss on settled interest rate agreements reclassified from AOCI into interest expense			
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.

Accumulated Other Comprehensive Income Components	Three Months Ended June 30, 2015 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

Accumulated Other Comprehensive Income Components	Three Months Ended June 30, 2014 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		Affected Line Item in the Statement of Income
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

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2015 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		Affected Line Item in the Statement of Income
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

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2014 Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)		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

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”, “str
words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; the impact of adverse economic conditions on our customers; the effects of inflation and changes in the availability and price of natural gas; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; the concentration of our distribution, pipeline and storage operations in Texas; increased competition from energy suppliers and alternative forms of energy; adverse weather conditions; the capital-intensive nature of our gas distribution business; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; the risks of accidents and additional operating costs associating with distributing, transporting and storing natural gas; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated 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

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	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

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

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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.

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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.