FR 16(7)(p) (CONT'D)

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

Form 10-Q

(Mark One)

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

For the quarterly period ended December 31, 2015

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of January 29, 2016.

Class	Shares Outstanding
No Par Value	102,106,896

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2015	September 30, 2015
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 9,502,944	$ 9,240,100
Less accumulated depreciation and amortization	1,849,657	1,809,520
Net property, plant and equipment	7,653,287	7,430,580
Current assets		
Cash and cash equivalents	78,903	28,653
Accounts receivable, net	456,904	295,160
Gas stored underground	236,017	236,603
Other current assets	91,446	70,569
Total current assets	863,270	630,985
Goodwill	742,702	742,702
Deferred charges and other assets	295,394	288,678
	$ 9,554,653	$ 9,092,945
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2015 — 102,079,316 shares; September 30, 2015 — 101,478,818 shares	$ 510	$ 507
Additional paid-in capital	2,242,307	2,230,591
Accumulated other comprehensive loss	(102,962)	(109,330)
Retained earnings	1,132,254	1,073,029
Shareholders' equity	3,272,109	3,194,797
Long-term debt	2,455,474	2,455,388
Total capitalization	5,727,583	5,650,185
Current liabilities		
Accounts payable and accrued liabilities	280,487	238,942
Other current liabilities	471,333	457,954
Short-term debt	763,236	457,927
Total current liabilities	1,515,056	1,154,823
Deferred income taxes	1,441,325	1,411,315
Regulatory cost of removal obligation	425,555	427,553
Pension and postretirement liabilities	289,939	287,373
Deferred credits and other liabilities	155,195	161,696
	$ 9,554,653	$ 9,092,945

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2015	2014
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 638,602	$ 846,772
Regulated pipeline segment	94,677	83,567
Nonregulated segment	272,524	462,288
Intersegment eliminations	(99,582)	(133,862)
	906,221	1,258,765
Purchased gas cost		
Regulated distribution segment	305,141	522,960
Regulated pipeline segment	—	—
Nonregulated segment	256,766	446,249
Intersegment eliminations	(99,449)	(133,729)
	462,458	835,480
Gross profit	443,763	423,285
Operating expenses		
Operation and maintenance	124,848	118,582
Depreciation and amortization	71,239	67,593
Taxes, other than income	51,471	49,385
Total operating expenses	247,558	235,560
Operating income	196,205	187,725
Miscellaneous expense	(1,209)	(1,707)
Interest charges	30,483	29,764
Income before income taxes	164,513	156,254
Income tax expense	61,652	58,659
Net income	$ 102,861	$ 97,595
Basic and diluted net income per share	$ 1.00	$ 0.96
Cash dividends per share	$ 0.42	$ 0.39
Basic and diluted weighted average shares outstanding	102,713	101,581

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended December 31	
	2015	2014
	(Unaudited) (In thousands)	
Net income	$ 102,861	$ 97,595
Other comprehensive income (loss), net of tax		
Net unrealized holding losses on available-for-sale securities, net of tax of $442 and $613	(768)	(1,067)
Cash flow hedges:		
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $2,749 and $(29,768)	4,783	(51,787)
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $1,505 and $(18,696)	2,353	(28,952)
Total other comprehensive income (loss)	6,368	(81,806)
Total comprehensive income	$ 109,229	$ 15,789

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2015	2014
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 102,861	$ 97,595
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	71,239	67,593
Charged to other accounts	326	275
Deferred income taxes	59,299	55,418
Other	4,407	4,889
Net assets / liabilities from risk management activities	(7,495)	(20,828)
Net change in operating assets and liabilities	(160,144)	(177,527)
Net cash provided by operating activities	70,493	27,415
Cash Flows From Investing Activities		
Capital expenditures	(291,674)	(261,313)
Other, net	1,029	(739)
Net cash used in investing activities	(290,645)	(262,052)
Cash Flows From Financing Activities		
Net increase in short-term debt	305,309	350,574
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	(43,636)	(39,592)
Repurchase of equity awards	—	(7,985)
Issuance of common stock	8,729	6,312
Net cash provided by financing activities	270,402	316,211
Net increase in cash and cash equivalents	50,250	81,574
Cash and cash equivalents at beginning of period	28,653	42,258
Cash and cash equivalents at end of period	$ 78,903	$ 123,832

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

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

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and pipeline businesses as well as other nonregulated natural gas businesses. Historically, our regulated businesses have generated over 90 percent of our consolidated net income.

Through our regulated distribution business, we deliver natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six regulated distribution divisions, which at December 31, 2015, covered service areas located in eight states. In addition, we transport natural gas for others through our distribution system. Our regulated businesses also include our regulated pipeline and storage operations, which include the transportation of natural gas to our North Texas distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our regulated distribution divisions operate.

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

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. 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, 2015. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2015 are not indicative of our results of operations for the full 2016 fiscal year, which ends September 30, 2016.

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, 2015.

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. 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 effect on our financial position, results of operations and cash flows, as well as the transition approach we will select.

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 November 2015, the FASB issued guidance that requires all deferred income tax liabilities and assets to be presented as noncurrent in a classified balance sheet. Currently, entities are required to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified balance sheet. The new standard will become effective for us beginning on October 1, 2017, with the option to early adopt, and can be applied either prospectively or retrospectively. The adoption of this guidance will have no impact on our results of operations or cash flows. The reclassification of amounts from current to noncurrent will affect the presentation of our balance sheet.

Regulatory assets and liabilities

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

Significant regulatory assets and liabilities as of December 31, 2015 and September 30, 2015 included the following:

	December 31, 2015	September 30, 2015
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs(1)	$ 116,485	$ 121,183
Infrastructure mechanisms(2)	43,385	32,813
Deferred gas costs	16,310	9,715
Recoverable loss on reacquired debt	15,680	16,319
APT annual adjustment mechanism	—	1,002
Rate case costs	1,568	1,533
Other	11,878	9,774
	$ 205,306	$ 192,339
Regulatory liabilities:		
Regulatory cost of removal obligation	$ 482,544	$ 483,676
Deferred gas costs	32,895	28,100
Asset retirement obligation	9,063	9,063
APT annual adjustment mechanism	1,721	—
Other	3,415	3,693
	$ 529,638	$ 524,532

(1) Includes $14.3 million and $16.6 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, which primarily consists of interest, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

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, 2015. We evaluate performance based on net income or loss of the respective operating units.

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

	Three Months Ended December 31, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 637,167	$ 23,407	$ 245,647	$ —	$ 906,221
Intersegment revenues	1,435	71,270	26,877	(99,582)	—
	638,602	94,677	272,524	(99,582)	906,221
Purchased gas cost	305,141	—	256,766	(99,449)	462,458
Gross profit	333,461	94,677	15,758	(133)	443,763
Operating expenses					
Operation and maintenance	91,349	27,088	6,544	(133)	124,848
Depreciation and amortization	57,334	12,770	1,135	—	71,239
Taxes, other than income	45,261	5,571	639	—	51,471
Total operating expenses	193,944	45,429	8,318	(133)	247,558
Operating income	139,517	49,248	7,440	—	196,205
Miscellaneous income (expense)	(752)	(429)	379	(407)	(1,209)
Interest charges	20,705	9,147	1,038	(407)	30,483
Income before income taxes	118,060	39,672	6,781	—	164,513
Income tax expense	44,805	14,086	2,761	—	61,652
Net income	$ 73,255	$ 25,586	$ 4,020	$ —	$ 102,861
Capital expenditures	$ 166,544	$ 125,283	$ (153)	$ —	$ 291,674

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

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

	December 31, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,779,479	$ 1,821,114	$ 52,694	$ —	$ 7,653,287
Investment in subsidiaries	1,020,629	—	—	(1,020,629)	—
Current assets					
Cash and cash equivalents	57,691	—	21,212	—	78,903
Assets from risk management activities	716	—	18,229	—	18,945
Other current assets	589,257	20,008	420,897	(264,740)	765,422
Intercompany receivables	943,005	—	—	(943,005)	—
Total current assets	1,590,669	20,008	460,338	(1,207,745)	863,270
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	96	—	—	—	96
Deferred charges and other assets	277,662	17,095	541	—	295,298
	$ 9,243,984	$ 1,990,759	$ 548,284	$ (2,228,374)	$ 9,554,653
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,272,109	$ 602,861	$ 417,768	$ (1,020,629)	$ 3,272,109
Long-term debt	2,455,474	—	—	—	2,455,474
Total capitalization	5,727,583	602,861	417,768	(1,020,629)	5,727,583
Current liabilities					
Short-term debt	1,017,236	—	—	(254,000)	763,236
Liabilities from risk management activities	6,738	—	—	—	6,738
Other current liabilities	625,055	28,197	102,570	(10,740)	745,082
Intercompany payables	—	923,366	19,639	(943,005)	—
Total current liabilities	1,649,029	951,563	122,209	(1,207,745)	1,515,056
Deferred income taxes	1,008,353	434,497	(1,525)	—	1,441,325
Noncurrent liabilities from risk management activities	103,337	—	—	—	103,337
Regulatory cost of removal obligation	425,555	—	—	—	425,555
Pension and postretirement liabilities	289,939	—	—	—	289,939
Deferred credits and other liabilities	40,188	1,838	9,832	—	51,858
	$ 9,243,984	$ 1,990,759	$ 548,284	$ (2,228,374)	$ 9,554,653

	September 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,670,306	$ 1,706,449	$ 53,825	$ —	$ 7,430,580
Investment in subsidiaries	1,038,670	—	(2,096)	(1,036,574)	—
Current assets					
Cash and cash equivalents	23,863	—	4,790	—	28,653
Assets from risk management activities	378	—	8,854	—	9,232
Other current assets	426,270	24,628	480,503	(338,301)	593,100
Intercompany receivables	887,713	—	—	(887,713)	—
Total current assets	1,338,224	24,628	494,147	(1,226,014)	630,985
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	368	—	—	—	368
Deferred charges and other assets	265,693	17,288	5,329	—	288,310
	$ 8,888,710	$ 1,880,907	$ 585,916	$ (2,262,588)	$ 9,092,945
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,194,797	$ 577,275	$ 461,395	$ (1,038,670)	$ 3,194,797
Long-term debt	2,455,388	—	—	—	2,455,388
Total capitalization	5,650,185	577,275	461,395	(1,038,670)	5,650,185
Current liabilities					
Short-term debt	782,927	—	—	(325,000)	457,927
Liabilities from risk management activities	9,568	—	—	—	9,568
Other current liabilities	569,273	29,780	99,480	(11,205)	687,328
Intercompany payables	—	867,409	20,304	(887,713)	—
Total current liabilities	1,361,768	897,189	119,784	(1,223,918)	1,154,823
Deferred income taxes	1,008,091	406,254	(3,030)	—	1,411,315
Noncurrent liabilities from risk management activities	110,539	—	—	—	110,539
Regulatory cost of removal obligation	427,553	—	—	—	427,553
Pension and postretirement liabilities	287,373	—	—	—	287,373
Deferred credits and other liabilities	43,201	189	7,767	—	51,157
	$ 8,888,710	$ 1,880,907	$ 585,916	$ (2,262,588)	$ 9,092,945

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three months ended December 31, 2015 and 2014 are calculated as follows:

	Three Months Ended December 31	
	2015	2014
	(In thousands, except per share amounts)	
Basic and Diluted Earnings Per Share		
Net income	$ 102,861	$ 97,595
Less: Income allocated to participating securities	172	216
Income available to common shareholders	$ 102,689	$ 97,379
Basic and diluted weighted average shares outstanding	102,713	101,581
Net income per share - Basic and Diluted	$ 1.00	$ 0.96

2011 Share Repurchase Program

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

5. Debt

The nature and terms of our debt instruments and credit facilities are described in detail in Note 5 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. Except as noted below, there were no material changes in the terms of our debt instruments during the three months ended December 31, 2015.

Long-term debt

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

	December 31, 2015	September 30, 2015
	(In thousands)	
Unsecured 6.35% Senior Notes, due June 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	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	4,526	4,612
	$ 2,455,474	$ 2,455,388

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

Short-term debt

Our short-term debt is utilized to fund ongoing working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity and capital expenditures. Our short-term borrowing requirements are affected primarily by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We currently finance our short-term borrowing requirements through a combination of a $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1.3 billion of working capital funding. At December 31, 2015 and September 30, 2015 a total of $763.2 million and $457.9 million was outstanding under our commercial paper program.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $1.3 billion of working capital funding, including a five-year $1.25 billion unsecured facility with an accordion feature, which, if utilized would increase the borrowing capacity to $1.5 billion, a $25 million unsecured facility and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.1 million at December 31, 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, 2016.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, has one uncommitted $25 million bilateral credit facility and one committed $15 million bilateral credit facility that were renewed and extended in December 2015. The uncommitted $25 million bilateral credit facility currently expires in March 2016 and the $15 million bilateral credit facility expires in September 2016. 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 $36.2 million at December 31, 2015.

AEH has a $500 million intercompany demand credit facility with AEC. This facility bears interest at a rate equal to the one-month LIBOR rate plus 3.00 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2016.

Shelf Registration

We filed a shelf registration statement with the Securities and Exchange Commission (SEC) on March 28, 2013 that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. At December 31, 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 December 31, 2015, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 51 percent. In addition, both the interest margin and the fee that we pay on unused amounts under certain of these facilities are subject to adjustment depending upon our credit ratings.

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

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

We were in compliance with all of our debt covenants as of December 31, 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 months ended December 31, 2015 and 2014 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,698	$ 5,051	$ 2,706	$ 3,896
Interest cost	7,095	6,699	3,106	3,596
Expected return on assets	(6,881)	(6,436)	(1,566)	(1,608)
Amortization of transition obligation	—	—	21	68
Amortization of prior service credit	(57)	(49)	(411)	(411)
Amortization of actuarial loss	3,320	3,917	(542)	—
Net periodic pension cost	$ 8,175	$ 9,182	$ 3,314	$ 5,541

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

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Discount rate	4.55%	4.43%	4.55%	4.43%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.00%	7.25%	4.45%	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, 2016. Based on that determination, we are not required to make a minimum contribution to our defined benefit plans during the first quarter of fiscal 2016, nor do we anticipate making a contribution during the remainder of the fiscal year.

We contributed $5.5 million to our other post-retirement benefit plans during the three months ended December 31, 2015. We expect to contribute between $15 million and $25 million to these plans during fiscal 2016.

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

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

Purchase Commitments

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. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. There were no material changes to the purchase commitments for the three months ended December 31, 2015.

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. Except for purchases made in the normal course of business under these contracts, there were no material changes to the purchase commitments for the three months ended December 31, 2015.

Our nonregulated segment maintains long-term contracts related to storage and transportation. These 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, 2015. There were no material changes to the estimated storage and transportation fees for the three months ended December 31, 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 December 31, 2015, rate cases were in progress in our Colorado, Kansas and Kentucky service areas and formula rate filing mechanisms were in progress in Colorado, Kansas, Louisiana and West Texas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

8. Financial Instruments

We currently use financial instruments in our regulated distribution and nonregulated segments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments, which have been tailored to our regulated distribution and nonregulated segments, and the related accounting for these financial instruments are fully described in Notes 2 and 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. During the three months ended December 31, 2015 there were no changes in our objectives, strategies and accounting for using financial instruments. Our financial instruments do not contain any credit-risk-related or other contingent features that could cause payments to be accelerated when our financial instruments are in net liability positions. The following summarizes those objectives and strategies.

Regulated Commodity Risk Management Activities

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

We typically seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2015-2016 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 33 percent, or 23.0 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Nonregulated Commodity Risk Management Activities

Our nonregulated segment is exposed to risks associated with changes in the market price of natural gas through the purchase, sale and delivery of natural gas to its customers at competitive prices. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Specifically, these operations use financial instruments in the following ways:

- *Gas delivery and related services* - Certain financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, are used to mitigate the commodity price risk associated with deliveries under fixed-priced forward contracts to either deliver gas to customers or purchase gas from suppliers. These financial instruments have maturity dates ranging from one to 58 months.
- *Transportation and storage services* - Our nonregulated operations use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges for accounting purposes.
- *Aggregating and purchasing gas supply* - Certain financial instruments, designated as fair value hedges, are used to hedge our natural gas inventory used in asset optimization activities.

Interest Rate Risk Management Activities

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

As of December 31, 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 December 31, 2015, we had $18.6 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 December 31, 2015, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2015, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Regulated Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(23,528)
	Cash Flow	—	63,305
	Not designated	11,792	51,663
		11,792	91,440

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of December 31, 2015 and September 30, 2015. The gross amounts of recognized assets and liabilities are netted within our unaudited Condensed Consolidated Balance Sheets to the extent that we have netting arrangements with the counterparties.

		Regulated Distribution		Nonregulated	
	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In thousands)			
December 31, 2015					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 24,704	$ (38,275)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	432	(8,821)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(103,142)	—	—
Total		—	(103,142)	25,136	(47,096)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	716	(6,738)	41,780	(42,232)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	96	(195)	17,577	(16,184)
Total		812	(6,933)	59,357	(58,416)
Gross Financial Instruments		812	(110,075)	84,493	(105,512)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(84,493)	84,493
Net Financial Instruments		812	(110,075)	—	(21,019)
Cash collateral		—	—	18,229	21,019
Net Assets/Liabilities from Risk Management Activities		$ 812	$ (110,075)	$ 18,229	$ —

	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2015					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 11,680	$ (36,067)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	126	(9,918)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(110,539)	—	—
Total		—	(110,539)	11,806	(45,985)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	378	(9,568)	65,239	(65,780)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	368	—	14,318	(14,218)
Total		746	(9,568)	79,557	(79,998)
Gross Financial Instruments		746	(120,107)	91,363	(125,983)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(91,363)	91,363
Net Financial Instruments		746	(120,107)	—	(34,620)
Cash collateral		—	—	8,854	34,620
Net Assets/Liabilities from Risk Management Activities		$ 746	$ (120,107)	$ 8,854	$ —

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 December 31, 2015 and 2014 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $7.9 million and $(2.2) million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

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

	Three Months Ended December 31 2015	Three Months Ended December 31 2014
	(In thousands)	
Commodity contracts	$ 5,744	$ 15,090
Fair value adjustment for natural gas inventory designated as the hedged item	2,161	(16,782)
Total (increase) decrease in purchased gas cost	$ 7,905	$ (1,692)
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ 1,289	$ 986
Timing ineffectiveness	6,616	(2,678)
	$ 7,905	$ (1,692)

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

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 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 December 31, 2015		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (22,965)	$ (22,965)
Loss arising from ineffective portion of commodity contracts	—	(43)	(43)
Total impact on purchased gas cost	—	(23,008)	(23,008)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(137)	—	(137)
Total Impact from Cash Flow Hedges	$ (137)	$ (23,008)	$ (23,145)

	Three Months Ended December 31, 2014		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Gain reclassified from AOCI for effective portion of commodity contracts	$ —	$ 344	$ 344
Loss arising from ineffective portion of commodity contracts	—	(490)	(490)
Total impact on purchased gas cost	—	(146)	(146)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(444)	—	(444)
Total Impact from Cash Flow Hedges	$ (444)	$ (146)	$ (590)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 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 December 31	
	2015	2014
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate agreements	$ 4,696	$ (52,069)
Forward commodity contracts	(11,656)	(28,742)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate agreements	87	282
Forward commodity contracts	14,009	(210)
Total other comprehensive income (loss) from hedging, net of tax[1]	$ 7,136	$ (80,739)

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

Deferred gains (losses) recorded in AOCI associated with our interest rate agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred gains (losses) associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 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)	$ (17,979)	$ (18,326)
Thereafter	(18,217)	(5,105)	(23,322)
Total[1]	$ (18,564)	$ (23,084)	$ (41,648)

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

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended December 31, 2015 and 2014 was an (increase) decrease in purchased gas cost of $(2.2) million and $0.9 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, 2015	$ 4,949	$ (88,842)	$ (25,437)	$ (109,330)
Other comprehensive income (loss) before reclassifications	(768)	4,696	(11,656)	(7,728)
Amounts reclassified from accumulated other comprehensive income	—	87	14,009	14,096
Net current-period other comprehensive income (loss)	(768)	4,783	2,353	6,368
December 31, 2015	$ 4,181	$ (84,059)	$ (23,084)	$ (102,962)

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2014	$ 7,662	$ (18,381)	$ (1,674)	$ (12,393)
Other comprehensive income (loss) before reclassifications	(1,063)	(52,069)	(28,742)	(81,874)
Amounts reclassified from accumulated other comprehensive income	(4)	282	(210)	68
Net current-period other comprehensive income (loss)	(1,067)	(51,787)	(28,952)	(81,806)
December 31, 2014	$ 6,595	$ (70,168)	$ (30,626)	$ (94,199)

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

	Three Months Ended December 31, 2015	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$ (137)	Interest charges
Commodity contracts	(22,965)	Purchased gas cost
	(23,102)	Total before tax
	9,006	Tax benefit
Total reclassifications	$ (14,096)	Net of tax

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

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, 2015. During the three months ended December 31, 2015, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 6 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2015.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2015 and September 30, 2015. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	December 31, 2015
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 812	$ —	$ —	$ 812
Nonregulated segment	—	84,493	—	(66,264)	18,229
Total financial instruments	—	85,305	—	(66,264)	19,041
Hedged portion of gas stored underground	53,347	—	—	—	53,347
Available-for-sale securities					
Money market funds	—	72	—	—	72
Registered investment companies	41,978	—	—	—	41,978
Bonds	—	33,129	—	—	33,129
Total available-for-sale securities	41,978	33,201	—	—	75,179
Total assets	$ 95,325	$ 118,506	$ —	$ (66,264)	$ 147,567
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 110,075	$ —	$ —	$ 110,075
Nonregulated segment	—	105,512	—	(105,512)	—
Total liabilities	$ —	$ 215,587	$ —	$ (105,512)	$ 110,075

	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, 2015
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 746	$ —	$ —	$ 746
Nonregulated segment	—	91,363	—	(82,509)	8,854
Total financial instruments	—	92,109	—	(82,509)	9,600
Hedged portion of gas stored underground	43,901	—	—	—	43,901
Available-for-sale securities					
Money market funds	—	1,072	—	—	1,072
Registered investment companies	40,619	—	—	—	40,619
Bonds	—	32,509	—	—	32,509
Total available-for-sale securities	40,619	33,581	—	—	74,200
Total assets	$ 84,520	$ 125,690	$ —	$ (82,509)	$ 127,701
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 120,107	$ —	$ —	$ 120,107
Nonregulated segment	—	125,983	—	(125,983)	—
Total liabilities	$ —	$ 246,090	$ —	$ (125,983)	$ 120,107

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

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of December 31, 2015, we had $39.2 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $21.0 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $18.2 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, 2015, we had $43.5 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $34.6 million was used to offset current and noncurrent risk management liabilities under master netting arrangements and the remaining $8.9 million is classified as current risk management assets.

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

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of December 31, 2015				
Domestic equity mutual funds	$ 30,054	$ 6,843	$ (1,133)	$ 35,764
Foreign equity mutual funds	5,346	868	—	6,214
Bonds	33,149	40	(60)	33,129
Money market funds	72	—	—	72
	$ 68,621	$ 7,751	$ (1,193)	$ 75,179
As of September 30, 2015				
Domestic equity mutual funds	$ 27,643	$ 7,332	$ (456)	$ 34,519
Foreign equity mutual funds	5,261	905	(66)	6,100
Bonds	32,423	106	(20)	32,509
Money market funds	1,072	—	—	1,072
	$ 66,399	$ 8,343	$ (542)	$ 74,200

At December 31, 2015 and September 30, 2015, our available-for-sale securities included $42.1 million and $41.7 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At December 31, 2015, we maintained investments in bonds that have contractual maturity dates ranging from January 2016 through September 2020.

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

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of December 31, 2015 and September 30, 2015:

	December 31, 2015	September 30, 2015
	(In thousands)	
Carrying Amount	$ 2,460,000	$ 2,460,000
Fair Value	$ 2,666,801	$ 2,669,323

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, 2015. During the three months ended December 31, 2015, there were no material changes in our concentration of credit risk.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of December 31, 2015 and the related condensed consolidated statements of income, comprehensive income and cash flows for the three-month periods ended December 31, 2015 and 2014. These financial statements are the responsibility of the Company's management.

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

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

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2015, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended, not presented herein, and we expressed an unqualified audit opinion on those consolidated financial statements in our report dated November 6, 2015. In our opinion, the accompanying condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2015, is fairly stated, in all material respects, in relation to the consolidated balance sheets from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 2, 2016

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, 2015.

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

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

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six regulated distribution divisions, which at December 31, 2015 covered service areas located in eight states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems.

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

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

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

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

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

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015 and include the following:

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

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

During the first three months of fiscal 2015, we earned $102.9 million, or $1.00 per diluted share, a five percent increase over the first quarter of fiscal 2015. Regulated operations represented 96 percent of our consolidated net income for the three months ended December 31, 2015. The following table reflects the segregation of our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended December 31		
	2015	2014	Change
	(In thousands, except per share data)		
Regulated operations	$ 98,841	$ 93,422	$ 5,419
Nonregulated operations	4,020	4,173	(153)
Net income	$ 102,861	$ 97,595	$ 5,266
Diluted EPS from regulated operations	$ 0.96	$ 0.92	$ 0.04
Diluted EPS from nonregulated operations	0.04	0.04	—
Consolidated diluted EPS	$ 1.00	$ 0.96	$ 0.04

Positive rate outcomes achieved in our regulated businesses during fiscal 2015 offset the effect of weather that was 29 percent warmer than the prior-year period. As of December 31, 2015, we had completed four regulatory proceedings resulting in a $13.3 million increase in annual operating income and had seven ratemaking efforts in progress seeking $27.4 million of additional annual operating income.

Capital expenditures for the first three months of fiscal 2016 were $291.7 million. Approximately 83 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 $1 billion and $1.1 billion for fiscal 2016. We funded our capital expenditure program primarily through operating cash flows of $70.5 million and net short-term borrowings.

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 7.7 percent for fiscal 2016.

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 includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

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

Three Months Ended December 31, 2015 compared with Three Months Ended December 31, 2014

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

	Three Months Ended December 31		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 333,461	$ 323,812	$ 9,649
Operating expenses	193,944	185,715	8,229
Operating income	139,517	138,097	1,420
Miscellaneous expense	(752)	(1,329)	577
Interest charges	20,705	21,640	(935)
Income before income taxes	118,060	115,128	2,932
Income tax expense	44,805	43,741	1,064
Net income	$ 73,255	$ 71,387	$ 1,868
Consolidated regulated distribution sales volumes — MMcf	68,717	86,922	(18,205)
Consolidated regulated distribution transportation volumes — MMcf	32,211	36,512	(4,301)
Total consolidated regulated distribution throughput — MMcf	100,928	123,434	(22,506)
Consolidated regulated distribution average cost of gas per Mcf sold	$ 4.44	$ 6.02	$ (1.58)

Income for our regulated distribution segment increased three percent, primarily due to a $9.6 million increase in gross profit, partially offset by an $8.2 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $13.5 million net increase in rate adjustments. Our Mid-Tex Division accounted for $7.1 million of this increase. We also experienced increases in our Mississippi and West Texas Divisions.
- a $1.3 million decrease in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $0.3 million decrease in the related tax expense.
- a $1.1 million decrease in consumption. Current-quarter weather was 29 percent warmer than the prior-year quarter, before adjusting for weather normalization mechanisms. As a result, sales volumes decreased 21 percent.

The increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to increased operation and maintenance expenses due to increased administrative expenses, increased property taxes 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 December 31, 2015 and 2014. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31		
	2015	2014	Change
	(In thousands)		
Mid-Tex	$ 68,131	$ 59,114	$ 9,017
Kentucky/Mid-States	18,918	19,796	(878)
Louisiana	15,052	16,725	(1,673)
West Texas	12,930	11,098	1,832
Mississippi	12,827	14,299	(1,472)
Colorado-Kansas	10,126	9,989	137
Other	1,533	7,076	(5,543)
Total	$ 139,517	$ 138,097	$ 1,420

Recent Ratemaking Developments

The amounts described in the following sections represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling. During the first three months of fiscal 2016, we completed four regulatory proceedings, resulting in a $13.3 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Annual formula rate mechanisms	$ 13,346
Rate case filings	—
Other rate activity	—
	$ 13,346

Additionally, the following ratemaking efforts seeking $27.4 million in annual operating income were in progress as of December 31, 2015:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Rate Case[1]	Colorado	$ 5,276
Colorado-Kansas	Infrastructure Mechanism[2]	Colorado	764
Colorado-Kansas	Rate Case	Kansas	5,667
Colorado-Kansas	Ad Valorem Tax Rider[3]	Kansas	(183)
Kentucky/Mid-States	Rate Case	Kentucky	5,531
Louisiana	Formula Rate Filing	Trans LA	6,216
West Texas	Formula Rate Filing	WT Cities	4,168
			$ 27,439

(1) The Colorado Public Utilities Commission (PUC) issued a final order approving a $2.1 million increase in annual operating income on January 1, 2016.

(2) The PUC allowed the $0.8 million requested amount effected by operation of law on January 1, 2016.

(3) 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.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have formula rate mechanisms in our Louisiana, Mississippi and Tennessee operations and in substantially all of our Texas divisions. Additionally, we have specific infrastructure programs in substantially all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	**Infrastructure Programs**	**Formula Rate Mechanisms**
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Infrastructure Reliability Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following annual formula rate mechanisms had approval dates during the three months ended December 31, 2015.

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income (In thousands)	Effective Date
2016 Filings:				
Mississippi	Mississippi-SRF(1)	10/31/2016	$ 9,192	01/01/2016
Mississippi	Mississippi-SGR (2)	10/31/2016	250	12/01/2015
Kentucky/Mid-States	Kentucky-PRP	09/30/2016	3,786	10/01/2015
Kentucky/Mid-States	Virginia-SAVE	09/30/2016	118	10/01/2015
Total 2016 Filings			$ 13,346	

(1) The commission issued a final order approving a $9.2 million increase in annual operating income on December 21, 2015 with an effective date of January 1, 2016.

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

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. No rate cases were completed during the three months ended December 31, 2015.

Other Ratemaking Activity

No other ratemaking activity was completed during the three months ended December 31, 2015.

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 and stores natural gas for our Mid-Tex Division and third party local distribution companies and manages five underground storage facilities in Texas. We also provide interruptible transportation, storage and ancillary services to electric generation and industrial customers as well as producers, marketers and other shippers.

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 and storage 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 the volumes of gas transported for shippers through our pipeline system and the rates for such transportation.

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 transporter 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. Additionally, APT annually uses GRIP to recover capital costs incurred in the prior calendar-year.

Three Months Ended December 31, 2015 compared with Three Months Ended December 31, 2014

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

	Three Months Ended December 31		
	2015	**2014**	**Change**
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 68,287	$ 60,079	$ 8,208
Third-party transportation	21,288	20,394	894
Storage and park and lend services	976	1,004	(28)
Other	4,126	2,090	2,036
Gross profit	94,677	83,567	11,110
Operating expenses	45,429	40,862	4,567
Operating income	49,248	42,705	6,543
Miscellaneous expense	(429)	(252)	(177)
Interest charges	9,147	8,324	823
Income before income taxes	39,672	34,129	5,543
Income tax expense	14,086	12,094	1,992
Net income	$ 25,586	$ 22,035	$ 3,551
Gross pipeline transportation volumes — MMcf	178,202	181,362	(3,160)
Consolidated pipeline transportation volumes — MMcf	129,159	120,634	8,525

Net income for our regulated pipeline segment increased 16 percent, primarily due to an $11.1 million increase in gross profit, partially offset by a $4.6 million increase in operating expenses. The increase in gross profit primarily reflects a $10.1 million increase in rates from the approved 2015 GRIP filing. Consolidated volumes are up primarily due to increased market demand from electric generation customers.

Operating expenses increased $4.6 million, primarily due to increased levels of pipeline and right-of-way maintenance activities to improve the safety and reliability of our system and increased depreciation expense associated with increased capital investments.

Nonregulated Segment

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

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

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

Our nonregulated activities are significantly influenced by competitive factors in the industry and general economic conditions. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of buying, selling and delivering natural gas to offer more competitive pricing to those customers.

Natural gas prices can influence:

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

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

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Increased or decreased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

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

Three Months Ended December 31, 2015 compared with Three Months Ended December 31, 2014

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

	Three Months Ended December 31		
	2015	2014	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 11,850	$ 10,759	$ 1,091
Storage and transportation services	3,255	3,313	(58)
Other	(11,251)	(5,831)	(5,420)
Total realized margins	3,854	8,241	(4,387)
Unrealized margins	11,904	7,798	4,106
Gross profit	15,758	16,039	(281)
Operating expenses	8,318	9,116	(798)
Operating income	7,440	6,923	517
Miscellaneous income	379	300	79
Interest charges	1,038	226	812
Income before income taxes	6,781	6,997	(216)
Income tax expense	2,761	2,824	(63)
Net income	$ 4,020	$ 4,173	$ (153)
Gross nonregulated delivered gas sales volumes — MMcf	96,733	108,193	(11,460)
Consolidated nonregulated delivered gas sales volumes — MMcf	85,131	90,930	(5,799)
Net physical position (Bcf)	23.5	17.1	6.4

The $0.3 million quarter-over-quarter decrease in gross profit reflects a $4.4 million decrease in realized margins, combined with a $4.1 million increase in unrealized margins. The $4.4 million decrease in realized margins primarily reflects:

- A $1.1 million increase in gas delivery and related services margins, primarily due to an increase in per-unit margins from 10 cents to 12 cents per Mcf, partially offset by a six percent decrease in consolidated sales volumes due to warmer weather in the current-year quarter.
- A $5.4 million decrease in other realized margins, primarily due to larger losses on the settlement of financial positions in a period of falling gas prices combined with increased third-party storage fees.

Unrealized margins increased $4.1 million, primarily due to the quarter-over-quarter favorable movement of the physical mark on the fair value natural gas inventory hedged positions.

Operating expenses decreased $0.8 million, primarily due to lower bad debt expense.

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 under 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 on file with the Securities and Exchange Commission (SEC) that originally permitted us to issue a total of $1.75 billion in common stock and/or debt securities. As of December 31, 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 December 31, 2015, September 30, 2015 and December 31, 2014:

	December 31, 2015		September 30, 2015		December 31, 2014	
	(In thousands, except percentages)					
Short-term debt	$ 763,236	11.8%	$ 457,927	7.5%	$ 550,903	9.1%
Long-term debt	2,455,474	37.8%	2,455,388	40.2%	2,455,131	40.4%
Shareholders' equity	3,272,109	50.4%	3,194,797	52.3%	3,063,925	50.5%
Total	$ 6,490,819	100.0%	$ 6,108,112	100.0%	$ 6,069,959	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 three months ended December 31, 2015 and 2014 are presented below.

	Three Months Ended December 31		
	2015	2014	Change
	(In thousands)		
Total cash provided by (used in)			
Operating activities	$ 70,493	$ 27,415	$ 43,078
Investing activities	(290,645)	(262,052)	(28,593)
Financing activities	270,402	316,211	(45,809)
Change in cash and cash equivalents	50,250	81,574	(31,324)
Cash and cash equivalents at beginning of period	28,653	42,258	(13,605)
Cash and cash equivalents at end of period	$ 78,903	$ 123,832	$ (44,929)

Cash flows from operating activities

Period-over-period changes in our operating cash flows are primarily attributable to changes in net income and working capital changes, particularly within our regulated distribution segment resulting from changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the three months ended December 31, 2015, we generated cash flow of $70.5 million from operating activities compared with $27.4 million for the three months ended December 31, 2014. The $43.1 million increase in operating cash flows primarily reflects the timing of customer collections and vendor payments.

Cash flows from investing activities

In executing our regulatory strategy, we target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions 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 our ongoing construction program, which 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. Over the last three fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system. We anticipate our annual capital spending will be in the range of $1 billion to $1.1 billion through fiscal 2018.

For the three months ended December 31, 2015, capital expenditures were $291.7 million, compared with $261.3 million in the prior-year period. The $30.4 million increase primarily reflects an 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 three months ended December 31, 2015, our financing activities generated $270.4 million of cash compared with $316.2 million generated in the prior-year period. The $45.8 million decrease of cash generated is primarily due to lower net short-term debt borrowings due to higher operating cash flow and period-over-period changes in working capital funding needs compared to the prior year.

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

	Three Months Ended December 31	
	2015	2014
Shares issued:		
Direct Stock Purchase Plan	35,417	60,936
1998 Long-Term Incentive Plan	458,607	477,649
Retirement Savings Plan and Trust	106,474	75,580
Outside Directors Stock-for-Fee Plan	—	424
Total shares issued	600,498	614,589

The year-over-year decrease in the number of shares issued primarily reflects a decrease in shares issued under the 1998 Long-Term Incentive Plan. For the three months ended December 31, 2015, we did not cancel and retire any shares attributable to federal income tax withholdings on equity awards. For the three months ended December 31, 2014, we canceled and retired 148,464 such shares.

Credit Facilities

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

We finance our short-term borrowing requirements through a combination of a $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.3 billion of working capital funding. As of December 31, 2015, the amount available to us under our credit facilities, net of outstanding letters of credit, was $0.6 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 December 31, 2015, Moody's and Fitch maintained a stable outlook. S&P issued a revised outlook from stable to positive on October 29, 2015, citing the potential for an upgraded rating in the future if we maintain our current level of financial performance as capital spending levels remain elevated. Our current debt ratings are all considered investment grade and are as follows:

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

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 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 three months ended December 31, 2015.

Risk Management Activities

We conduct risk management activities through our regulated distribution and nonregulated segments. In our regulated distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

In our nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our regulated distribution segment's financial instruments for the three months ended December 31, 2015 and 2014:

	Three Months Ended December 31	
	2015	2014
	(In thousands)	
Fair value of contracts at beginning of period	$ (119,361)	$ 14,284
Contracts realized/settled	(12,630)	(23,156)
Fair value of new contracts	(183)	(365)
Other changes in value	22,911	(85,611)
Fair value of contracts at end of period	$ (109,263)	$ (94,848)

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

	Fair Value of Contracts at December 31, 2015				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
			(In thousands)		
Prices actively quoted	$ (6,022)	$ (103,241)	$ —	$ —	$ (109,263)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (6,022)	$ (103,241)	$ —	$ —	$ (109,263)

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

	Three Months Ended December 31	
	2015	2014
	(In thousands)	
Fair value of contracts at beginning of period	$ (34,620)	$ (3,033)
Contracts realized/settled	18,898	7,165
Fair value of new contracts	—	—
Other changes in value	(5,297)	(30,231)
Fair value of contracts at end of period	(21,019)	(26,099)
Netting of cash collateral	39,248	43,501
Cash collateral and fair value of contracts at period end	$ 18,229	$ 17,402

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

	Fair Value of Contracts at December 31, 2015				
	Maturity in Years				
<u>Source of Fair Value</u>	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$ (14,023)	$ (6,378)	$ (618)	$ —	$ (21,019)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (14,023)	$ (6,378)	$ (618)	$ —	$ (21,019)

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2015 and 2014, our total net periodic pension and other benefits costs were $11.5 million and $14.7 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 2016 costs were determined using a September 30, 2015 measurement date. As of September 30, 2015, interest and corporate bond rates utilized to determine our discount rates were higher than the interest and corporate bond rates as of September 30, 2014, the measurement date for our fiscal 2015 net periodic cost. Therefore, we increased the discount rate used to measure our fiscal 2016 net periodic cost from 4.43 percent to 4.55 percent. We lowered our expected return on plan assets from 7.25 percent to 7.00 percent in the determination of our fiscal 2016 net periodic pension cost based upon expected market returns for our targeted asset allocation. 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 and in October 2015, the Society of Actuaries issued an additional report related to mortality tables and the mortality improvement scale. As of September 30, 2015, we updated our assumed mortality tables to incorporate both of these updates. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2016 net periodic pension cost to decrease by approximately 20 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 the determination as of January 1, 2015, we are not required to make a minimum contribution to our defined benefit plans during fiscal 2016. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels.

For the three months ended December 31, 2015 we contributed $5.5 million to our postretirement medical plans. We anticipate contributing between $15 million and $25 million to our postretirement plans during fiscal 2016.

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

OPERATING STATISTICS AND OTHER INFORMATION

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

Regulated Distribution Sales and Statistical Data

	Three Months Ended December 31	
	2015	2014
METERS IN SERVICE, end of period		
Residential	2,891,676	2,862,369
Commercial	265,766	261,593
Industrial	1,489	1,538
Public authority and other	8,421	8,451
Total meters	3,167,352	3,133,951
INVENTORY STORAGE BALANCE — Bcf	58.5	53.0
SALES VOLUMES — MMcf[1]		
Gas sales volumes		
Residential	40,169	52,218
Commercial	23,418	28,715
Industrial	3,456	3,890
Public authority and other	1,674	2,099
Total gas sales volumes	68,717	86,922
Transportation volumes	35,124	38,835
Total throughput	103,841	125,757
OPERATING REVENUES (000's)[1]		
Gas sales revenues		
Residential	$ 415,985	$ 541,725
Commercial	172,025	241,630
Industrial	14,285	22,911
Public authority and other	10,533	14,998
Total gas sales revenues	612,828	821,264
Transportation revenues	19,481	19,152
Other gas revenues	6,293	6,356
Total operating revenues	$ 638,602	$ 846,772
Average cost of gas per Mcf sold	$ 4.44	$ 6.02

See footnote following these tables.

Regulated Pipeline and Nonregulated Operations Sales and Statistical Data

	Three Months Ended December 31	
	2015	**2014**
CUSTOMERS, end of period		
Industrial	758	747
Municipal	128	129
Other	523	539
Total	1,409	1,415
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	25.4	21.6
REGULATED PIPELINE VOLUMES — MMcf[1]	178,202	181,362
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[1]	96,733	108,193
OPERATING REVENUES (000's)[1]		
Regulated pipeline	$ 94,677	$ 83,567
Nonregulated	272,524	462,288
Total operating revenues	$ 367,201	$ 545,855

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, 2015. During the three months ended December 31, 2015, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2015 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the three months ended December 31, 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, 2015. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. *Exhibits*

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

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and
Chief Financial Officer
(Duly authorized signatory)

Date: February 2, 2016

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.

CASE NO. 2017-00349
FR 16(7)(p)
ATTACHMENT 3

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2016

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of April 29, 2016.

Class	Shares Outstanding
No Par Value	102,233,265

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2016	September 30, 2015
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 9,722,228	$ 9,240,100
Less accumulated depreciation and amortization	1,882,815	1,809,520
Net property, plant and equipment	7,839,413	7,430,580
Current assets		
Cash and cash equivalents	47,918	28,653
Accounts receivable, net	361,582	295,160
Gas stored underground	190,961	236,603
Other current assets	52,451	65,890
Total current assets	652,912	626,306
Goodwill	742,702	742,702
Deferred charges and other assets	308,899	293,357
	$ 9,543,926	$ 9,092,945
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2016 — 102,209,505 shares; September 30, 2015 — 101,478,818 shares	$ 511	$ 507
Additional paid-in capital	2,255,875	2,230,591
Accumulated other comprehensive loss	(157,239)	(109,330)
Retained earnings	1,245,418	1,073,029
Shareholders' equity	3,344,565	3,194,797
Long-term debt	2,455,559	2,455,388
Total capitalization	5,800,124	5,650,185
Current liabilities		
Accounts payable and accrued liabilities	226,641	238,942
Other current liabilities	373,783	457,954
Short-term debt	626,929	457,927
Total current liabilities	1,227,353	1,154,823
Deferred income taxes	1,557,790	1,411,315
Regulatory cost of removal obligation	426,756	427,553
Pension and postretirement liabilities	294,377	287,373
Deferred credits and other liabilities	237,526	161,696
	$ 9,543,926	$ 9,092,945

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2016	2015
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 849,685	$ 1,130,613
Regulated pipeline segment	95,703	91,730
Nonregulated segment	287,395	438,322
Intersegment eliminations	(100,490)	(120,597)
	1,132,293	1,540,068
Purchased gas cost		
Regulated distribution segment	440,543	724,378
Regulated pipeline segment	—	—
Nonregulated segment	274,296	415,416
Intersegment eliminations	(100,357)	(120,464)
	614,482	1,019,330
Gross profit	517,811	520,738
Operating expenses		
Operation and maintenance	133,666	133,460
Depreciation and amortization	71,972	68,022
Taxes, other than income	62,157	69,046
Total operating expenses	267,795	270,528
Operating income	250,016	250,210
Miscellaneous expense	(685)	(1,561)
Interest charges	27,560	27,447
Income before income taxes	221,771	221,202
Income tax expense	79,961	83,518
Net income	$ 141,810	$ 137,684
Basic and diluted net income per share	$ 1.38	$ 1.35
Cash dividends per share	$ 0.42	$ 0.39
Basic and diluted weighted average shares outstanding	102,946	101,746

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2016	2015
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 1,488,287	$ 1,977,385
Regulated pipeline segment	190,380	175,297
Nonregulated segment	559,919	900,610
Intersegment eliminations	(200,072)	(254,459)
	2,038,514	2,798,833
Purchased gas cost		
Regulated distribution segment	745,684	1,247,338
Regulated pipeline segment	—	—
Nonregulated segment	531,062	861,665
Intersegment eliminations	(199,806)	(254,193)
	1,076,940	1,854,810
Gross profit	961,574	944,023
Operating expenses		
Operation and maintenance	258,514	252,042
Depreciation and amortization	143,211	135,615
Taxes, other than income	113,628	118,431
Total operating expenses	515,353	506,088
Operating income	446,221	437,935
Miscellaneous expense	(1,894)	(3,268)
Interest charges	58,043	57,211
Income before income taxes	386,284	377,456
Income tax expense	141,613	142,177
Net income	$ 244,671	$ 235,279
Basic and diluted net income per share	$ 2.38	$ 2.31
Cash dividends per share	$ 0.84	$ 0.78
Basic and diluted weighted average shares outstanding	102,837	101,667

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31		Six Months Ended March 31	
	2016	2015	2016	2015
	(Unaudited) (In thousands)			
Net income	$ 141,810	$ 137,684	$ 244,671	$ 235,279
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(505), $484, $(947) and $(129)	(879)	962	(1,647)	(105)
Cash flow hedges:				
Amortization and unrealized loss on interest rate agreements, net of tax of $(30,819), $(18,778), $(28,070) and $(48,546)	(53,618)	(32,669)	(48,835)	(84,456)
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $140, $(1,395), $1,645 and $(20,091)	220	(2,182)	2,573	(31,134)
Total other comprehensive loss	(54,277)	(33,889)	(47,909)	(115,695)
Total comprehensive income	$ 87,533	$ 103,795	$ 196,762	$ 119,584

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31 2016	Six Months Ended March 31 2015
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 244,671	$ 235,279
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	143,211	135,615
Charged to other accounts	645	566
Deferred income taxes	132,456	131,292
Other	10,355	10,332
Net assets / liabilities from risk management activities	9,528	(29,091)
Net change in operating assets and liabilities	(85,090)	56,855
Net cash provided by operating activities	455,776	540,848
Cash Flows From Investing Activities		
Capital expenditures	(538,233)	(441,644)
Other, net	1,888	(1,346)
Net cash used in investing activities	(536,345)	(442,990)
Cash Flows From Financing Activities		
Net increase in short-term debt	169,002	21,839
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	(86,809)	(78,074)
Repurchase of equity awards	—	(7,985)
Issuance of common stock	17,641	12,727
Net cash provided by (used in) financing activities	99,834	(44,591)
Net increase in cash and cash equivalents	19,265	53,267
Cash and cash equivalents at beginning of period	28,653	42,258
Cash and cash equivalents at end of period	$ 47,918	$ 95,525

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2016

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and pipeline businesses as well as other nonregulated natural gas businesses. Historically, our regulated businesses have generated over 90 percent of our consolidated net income.

Through our regulated distribution business, we deliver natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six regulated distribution divisions, which at March 31, 2016, 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, 2015. 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, 2015. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2016 are not indicative of our results of operations for the full 2016 fiscal year, which ends September 30, 2016.

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, 2015.

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

During the second quarter of fiscal 2016, 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. 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 effect on our financial position, results of operations and cash flows, as well as the transition approach we will select.

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 November 2015, the FASB issued guidance that requires all deferred income tax liabilities and assets to be presented as noncurrent in a classified balance sheet. Currently, entities are required to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified balance sheet. The new standard will become effective for us beginning on October 1, 2017; however, as permitted under the new guidance, we have elected early adoption. The adoption of this guidance had no impact on our results of operations or cash flows. In accordance with the transition guidance, we have adopted this new guidance prospectively and prior periods have not been adjusted.

In January 2016, the FASB issued guidance related to the classification and measurement of financial instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning October 1, 2018; limited early adoption is permitted. We are currently evaluating the potential impact of this new guidance.

In February 2016, the FASB issued a comprehensive new leasing standard that will require lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The new standard will be effective for us beginning on October 1, 2019; early adoption is permitted. The new leasing standard requires modified retrospective transition, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. We are currently evaluating the effect on our financial position, results of operations and cash flows.

In March 2016, the FASB issued guidance to simplify the accounting and reporting of share-based payment arrangements. Key modifications required under the new guidance include:

- Recognition of all excess tax benefits and tax deficiencies associated with stock-based compensation as income tax expense or benefit in the income statement in the period the awards vest. The guidance also requires these income tax inflows and outflows to be classified as an operating activity.
- Simplification of the accounting for forfeitures.
- Clarification that cash paid by an employer when directly withholding shares for tax-withholding purposes should be classified as a financing activity.

The guidance will be effective for us beginning October 1, 2017; however, as permitted under the new guidance, we have elected early adoption. In accordance with the transition requirements, we recorded a $3.3 million income tax benefit for stock awards that vested during the current fiscal year. Additionally, we recorded a $14.5 million cumulative-effect increase to retained earnings with an offsetting increase to the Company's net operating loss (NOL) deferred tax asset to recognize the effect of excess tax benefits earned prior to September 30, 2015. Since we have adopted this new guidance prospectively, prior periods have not been adjusted.

Regulatory assets and liabilities

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

Significant regulatory assets and liabilities as of March 31, 2016 and September 30, 2015 included the following:

	March 31, 2016	September 30, 2015
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[(1)]	$ 113,483	$ 121,183
Infrastructure mechanisms[(2)]	53,698	32,813
Deferred gas costs	1,136	9,715
Recoverable loss on reacquired debt	15,040	16,319
APT annual adjustment mechanism	—	1,002
Rate case costs	1,796	1,533
Other	16,297	9,774
	$ 201,450	$ 192,339
Regulatory liabilities:		
Regulatory cost of removal obligations	$ 486,857	$ 483,676
Deferred gas costs	68,812	28,100
Asset retirement obligations	9,063	9,063
APT annual adjustment mechanism	640	—
Other	5,202	3,693
	$ 570,574	$ 524,532

(1) Includes $13.6 million and $16.6 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, which primarily consists of interest, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

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, 2015. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and six months ended March 31, 2016 and 2015 by segment are presented in the following tables:

	Three Months Ended March 31, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 847,487	$ 23,419	$ 261,387	$ —	$ 1,132,293
Intersegment revenues	2,198	72,284	26,008	(100,490)	—
	849,685	95,703	287,395	(100,490)	1,132,293
Purchased gas cost	440,543	—	274,296	(100,357)	614,482
Gross profit	409,142	95,703	13,099	(133)	517,811
Operating expenses					
Operation and maintenance	99,180	27,131	7,488	(133)	133,666
Depreciation and amortization	57,663	13,179	1,130	—	71,972
Taxes, other than income	54,686	6,738	733	—	62,157
Total operating expenses	211,529	47,048	9,351	(133)	267,795
Operating income	197,613	48,655	3,748	—	250,016
Miscellaneous income (expense)	(150)	(376)	292	(451)	(685)
Interest charges	18,717	9,145	149	(451)	27,560
Income before income taxes	178,746	39,134	3,891	—	221,771
Income tax expense	64,434	13,949	1,578	—	79,961
Net income	$ 114,312	$ 25,185	$ 2,313	$ —	$ 141,810
Capital expenditures	$ 176,080	$ 70,136	$ 343	$ —	$ 246,559

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

	Six Months Ended March 31, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,484,654	$ 46,826	$ 507,034	$ —	$ 2,038,514
Intersegment revenues	3,633	143,554	52,885	(200,072)	—
	1,488,287	190,380	559,919	(200,072)	2,038,514
Purchased gas cost	745,684	—	531,062	(199,806)	1,076,940
Gross profit	742,603	190,380	28,857	(266)	961,574
Operating expenses					
Operation and maintenance	190,529	54,219	14,032	(266)	258,514
Depreciation and amortization	114,997	25,949	2,265	—	143,211
Taxes, other than income	99,947	12,309	1,372	—	113,628
Total operating expenses	405,473	92,477	17,669	(266)	515,353
Operating income	337,130	97,903	11,188	—	446,221
Miscellaneous income (expense)	(902)	(805)	671	(858)	(1,894)
Interest charges	39,422	18,292	1,187	(858)	58,043
Income before income taxes	296,806	78,806	10,672	—	386,284
Income tax expense	109,239	28,035	4,339	—	141,613
Net income	$ 187,567	$ 50,771	$ 6,333	$ —	$ 244,671
Capital expenditures	$ 342,624	$ 195,419	$ 190	$ —	$ 538,233

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

Balance sheet information at March 31, 2016 and September 30, 2015 by segment is presented in the following tables:

	March 31, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,902,803	$ 1,884,620	$ 51,990	$ —	$ 7,839,413
Investment in subsidiaries	948,346	—	—	(948,346)	—
Current assets					
Cash and cash equivalents	38,464	—	9,454	—	47,918
Assets from risk management activities	637	—	6,837	—	7,474
Other current assets	430,759	17,465	356,348	(207,052)	597,520
Intercompany receivables	980,055	—	—	(980,055)	—
Total current assets	1,449,915	17,465	372,639	(1,187,107)	652,912
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	—	—	—	—	—
Deferred charges and other assets	290,737	17,742	420	—	308,899
	$ 9,167,250	$ 2,052,369	$ 459,760	$ (2,135,453)	$ 9,543,926
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,344,565	$ 628,045	$ 320,301	$ (948,346)	$ 3,344,565
Long-term debt	2,455,559	—	—	—	2,455,559
Total capitalization	5,800,124	628,045	320,301	(948,346)	5,800,124
Current liabilities					
Short-term debt	822,929	—	—	(196,000)	626,929
Liabilities from risk management activities	784	—	—	—	784
Other current liabilities	492,645	11,751	106,296	(11,052)	599,640
Intercompany payables	—	956,552	23,503	(980,055)	—
Total current liabilities	1,316,358	968,303	129,799	(1,187,107)	1,227,353
Deferred income taxes	1,102,679	455,277	(166)	—	1,557,790
Noncurrent liabilities from risk management activities	185,057	—	—	—	185,057
Regulatory cost of removal obligation	426,756	—	—	—	426,756
Pension and postretirement liabilities	294,377	—	—	—	294,377
Deferred credits and other liabilities	41,899	744	9,826	—	52,469
	$ 9,167,250	$ 2,052,369	$ 459,760	$ (2,135,453)	$ 9,543,926

	September 30, 2015				
	Regulated Distribution	**Regulated Pipeline**	**Nonregulated**	**Eliminations**	**Consolidated**
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,670,306	$ 1,706,449	$ 53,825	$ —	$ 7,430,580
Investment in subsidiaries	1,038,670	—	(2,096)	(1,036,574)	—
Current assets					
Cash and cash equivalents	23,863	—	4,790	—	28,653
Assets from risk management activities	378	—	8,854	—	9,232
Other current assets	421,591	24,628	480,503	(338,301)	588,421
Intercompany receivables	887,713	—	—	(887,713)	—
Total current assets	1,333,545	24,628	494,147	(1,226,014)	626,306
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	368	—	—	—	368
Deferred charges and other assets	270,372	17,288	5,329	—	292,989
	$ 8,888,710	$ 1,880,907	$ 585,916	$ (2,262,588)	$ 9,092,945
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,194,797	$ 577,275	$ 461,395	$ (1,038,670)	$ 3,194,797
Long-term debt	2,455,388	—	—	—	2,455,388
Total capitalization	5,650,185	577,275	461,395	(1,038,670)	5,650,185
Current liabilities					
Short-term debt	782,927	—	—	(325,000)	457,927
Liabilities from risk management activities	9,568	—	—	—	9,568
Other current liabilities	569,273	29,780	99,480	(11,205)	687,328
Intercompany payables	—	867,409	20,304	(887,713)	—
Total current liabilities	1,361,768	897,189	119,784	(1,223,918)	1,154,823
Deferred income taxes	1,008,091	406,254	(3,030)	—	1,411,315
Noncurrent liabilities from risk management activities	110,539	—	—	—	110,539
Regulatory cost of removal obligation	427,553	—	—	—	427,553
Pension and postretirement liabilities	287,373	—	—	—	287,373
Deferred credits and other liabilities	43,201	189	7,767	—	51,157
	$ 8,888,710	$ 1,880,907	$ 585,916	$ (2,262,588)	$ 9,092,945

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and six months ended March 31, 2016 and 2015 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2016	2015	2016	2015
	(In thousands, except per share amounts)			
Basic and Diluted Earnings Per Share				
Net income	$ 141,810	$ 137,684	$ 244,671	$ 235,279
Less: Income allocated to participating securities	231	296	405	520
Income available to common shareholders	$ 141,579	$ 137,388	$ 244,266	$ 234,759
Basic and diluted weighted average shares outstanding	102,946	101,746	102,837	101,667
Net income per share - Basic and Diluted	$ 1.38	$ 1.35	$ 2.38	$ 2.31

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, 2015. Except as noted below, there were no material changes in the terms of our debt instruments during the six months ended March 31, 2016.

Long-term debt

Long-term debt at March 31, 2016 and September 30, 2015 consisted of the following:

	March 31, 2016	September 30, 2015
	(In thousands)	
Unsecured 6.35% Senior Notes, due June 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	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	4,441	4,612
	$ 2,455,559	$ 2,455,388

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

Short-term debt

Our short-term debt is utilized to fund ongoing working capital needs, such as our seasonal requirements for gas supply, general corporate liquidity and capital expenditures. Our short-term borrowing requirements are affected primarily by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

We currently finance our short-term borrowing requirements through a combination of a $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. These facilities provide approximately $1.3 billion of working capital funding. At March 31, 2016 and September 30, 2015 a total of $626.9 million and $457.9 million was outstanding under our commercial paper program.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $1.3 billion of working capital funding, including a five-year $1.25 billion unsecured facility with an accordion feature, which, if utilized would increase the borrowing capacity to $1.5 billion, a $25 million unsecured facility and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.1 million at March 31, 2016.

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, 2016.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, has one uncommitted $25 million bilateral credit facility that was renewed and extended in March 2016 and one committed $15 million bilateral credit facility that was renewed and extended in December 2015. The uncommitted $25 million bilateral credit facility currently expires in December 2016 and the $15 million bilateral credit facility expires in September 2016. 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 $36.9 million at March 31, 2016.

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, 2016.

Debt Covenants

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2016, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 49 percent. In addition, both the interest margin and the fee that we pay on unused amounts under certain of these facilities are subject to adjustment depending upon our credit ratings.

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

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

We were in compliance with all of our debt covenants as of March 31, 2016. 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. Shareholders' Equity

Shelf Registration

On March 28, 2016, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $2.5 billion in common stock and/or debt securities, which replaced our registration statement that expired on March 28, 2016.

At-the-Market Equity Sales Program

On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement (the Agreement) with Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC in their capacity as agents and/or as principals (Agents). Under the terms of the Agreement, we may issue and sell, through any of the Agents, shares of our common stock, up to an aggregate offering price of $200 million, through the period ended March 28, 2019. We may also sell shares from time to time to an Agent for its own account at a price to be agreed upon at the time of sale. We will pay each Agent a commission of 1.0% of the gross offering proceeds of the shares sold through it as a sales agent. We have no obligation to offer or sell any shares under the Agreement, and may at any time suspend offers and sales under the Agreement. The shares will be issued pursuant to our shelf registration statement filed with the SEC on March 28, 2016. There were no transactions under the ATM program during the second fiscal quarter of 2016.

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan (LTIP), which became effective in October 1998 after approval by our shareholders. The LTIP is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

As of September 30, 2015, we were authorized to grant awards for up to a maximum of 8.7 million shares of common stock under this plan subject to certain adjustment provisions. In February 2016, our shareholders voted to increase the number of authorized LTIP shares by 2.5 million shares and to extend the term of the plan for an additional five years, through September 2021. On March 29, 2016, we filed with the SEC a registration statement on Form S-8 to register an additional 2.5 million shares; we also listed such shares with the New York Stock Exchange.

2011 Share Repurchase Program

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

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, 2015	$ 4,949	$ (88,842)	$ (25,437)	$ (109,330)
Other comprehensive loss before reclassifications	(1,568)	(49,008)	(19,185)	(69,761)
Amounts reclassified from accumulated other comprehensive income	(79)	173	21,758	21,852
Net current-period other comprehensive income (loss)	(1,647)	(48,835)	2,573	(47,909)
March 31, 2016	$ 3,302	$ (137,677)	$ (22,864)	$ (157,239)

	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 loss before reclassifications	(101)	(84,824)	(38,902)	(123,827)
Amounts reclassified from accumulated other comprehensive income	(4)	368	7,768	8,132
Net current-period other comprehensive income (loss)	(105)	(84,456)	(31,134)	(115,695)
March 31, 2015	$ 7,557	$ (102,837)	$ (32,808)	$ (128,088)

The following tables detail reclassifications out of AOCI for the three and six months ended March 31, 2016 and 2015. Amounts in parentheses below indicate decreases to net income in the statement of income.

Accumulated Other Comprehensive Income Components	Three Months Ended March 31, 2016 Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ 124	Operation and maintenance expense
	124	Total before tax
	(45)	Tax expense
	$ 79	Net of tax
Cash flow hedges		
Interest rate agreements	$ (136)	Interest charges
Commodity contracts	(12,703)	Purchased gas cost
	(12,839)	Total before tax
	5,004	Tax benefit
	$ (7,835)	Net of tax
Total reclassifications	$ (7,756)	Net of tax

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

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2016	
	Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$ 124	Operation and maintenance expense
	124	Total before tax
	(45)	Tax expense
	$ 79	Net of tax
Cash flow hedges		
Interest rate agreements	$ (273)	Interest charges
Commodity contracts	(35,668)	Purchased gas cost
	(35,941)	Total before tax
	14,010	Tax benefit
	$ (21,931)	Net of tax
Total reclassifications	$ (21,852)	Net of tax

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

7. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and six months ended March 31, 2016 and 2015 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.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,697	$ 5,051	$ 2,706	$ 3,896
Interest cost	7,094	6,698	3,106	3,597
Expected return on assets	(6,880)	(6,437)	(1,566)	(1,608)
Amortization of transition obligation	—	—	20	68
Amortization of prior service credit	(56)	(47)	(411)	(411)
Amortization of actuarial (gain) loss	3,320	3,916	(542)	—
Net periodic pension cost	$ 8,175	$ 9,181	$ 3,313	$ 5,542

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 9,395	$ 10,102	$ 5,412	$ 7,792
Interest cost	14,189	13,397	6,212	7,193
Expected return on assets	(13,761)	(12,873)	(3,132)	(3,216)
Amortization of transition obligation	—	—	41	136
Amortization of prior service credit	(113)	(96)	(822)	(822)
Amortization of actuarial (gain) loss	6,640	7,833	(1,084)	—
Net periodic pension cost	$ 16,350	$ 18,363	$ 6,627	$ 11,083

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2016 and 2015 are as follows:

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Discount rate	4.55%	4.43%	4.55%	4.43%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.00%	7.25%	4.45%	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, 2016. Based on that determination, we are not required to make a minimum contribution to our defined benefit plans; however, we may consider whether a voluntary contribution is prudent to maintain certain funding levels.

We contributed $9.0 million to our other post-retirement benefit plans during the six months ended March 31, 2016. We expect to contribute between $15 million and $25 million to these plans during fiscal 2016.

8. 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, 2015, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2016.

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. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. There were no material changes to the purchase commitments for the six months ended March 31, 2016.

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015. Except for purchases made in the normal course of business under these contracts, there were no material changes to the purchase commitments for the six months ended March 31, 2016.

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, 2015. There were no material changes to the estimated storage and transportation fees for the six months ended March 31, 2016.

Regulatory Matters

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

As of March 31, 2016, a rate case was in progress in our Kentucky service area, formula rate filing mechanisms were in progress in our Atmos Pipeline-Texas, Louisiana, Mid-Tex and Tennessee service areas, infrastructure mechanisms were in progress in our Mississippi and West Texas service areas and an expedited rate filing was in progress in Virginia. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

9. 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, 2015. During the six months ended March 31, 2016 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 2015-2016 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 33 percent, or 23.0 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 57 months.
- *Transportation and storage services* - Our nonregulated operations use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges for accounting purposes.
- *Aggregating and purchasing gas supply* - Certain financial instruments, designated as fair value hedges, are used to hedge our natural gas inventory used in asset optimization activities.

Interest Rate Risk Management Activities

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

As of March 31, 2016, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $250 million and $450 million unsecured senior notes in fiscal 2017 and fiscal 2019, at 3.37% and 3.78%, which we designated as cash flow hedges at the time the swaps were executed. As of March 31, 2016, we had $18.5 million of net realized losses in accumulated other comprehensive income (AOCI) associated with the settlement of financial instruments used to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes, which will be recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these settled amounts extend through fiscal 2045.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of March 31, 2016, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of March 31, 2016, 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	—	(35,770)
	Cash Flow	—	46,553
	Not designated	4,690	55,854
		4,690	66,637

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of March 31, 2016 and September 30, 2015. The gross amounts of recognized assets and liabilities are netted within our unaudited Condensed Consolidated Balance Sheets to the extent that we have netting arrangements with the counterparties.

		Regulated Distribution		Nonregulated	
	Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
			(In thousands)		
March 31, 2016					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 16,032	$ (37,251)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	920	(6,194)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(187,717)	—	—
Total		—	(187,717)	16,952	(43,445)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	637	(784)	39,964	(33,248)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	14,767	(11,075)
Total		637	(784)	54,731	(44,323)
Gross Financial Instruments		637	(188,501)	71,683	(87,768)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(71,683)	71,683
Net Financial Instruments		637	(188,501)	—	(16,085)
Cash collateral		—	2,660	6,837	16,085
Net Assets/Liabilities from Risk Management Activities		$ 637	$ (185,841)	$ 6,837	$ —

	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2015					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 11,680	$ (36,067)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	126	(9,918)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(110,539)	—	—
Total		—	(110,539)	11,806	(45,985)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	378	(9,568)	65,239	(65,780)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	368	—	14,318	(14,218)
Total		746	(9,568)	79,557	(79,998)
Gross Financial Instruments		746	(120,107)	91,363	(125,983)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(91,363)	91,363
Net Financial Instruments		746	(120,107)	—	(34,620)
Cash collateral		—	—	8,854	34,620
Net Assets/Liabilities from Risk Management Activities		$ 746	$ (120,107)	$ 8,854	$ —

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of purchased gas cost and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended March 31, 2016 and 2015 we recognized a loss arising from fair value and cash flow hedge ineffectiveness of $3.3 million and $2.3 million. For the six months ended March 31, 2016 and 2015 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $4.6 million and $(4.5) million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended March 31, 2016 and 2015 is presented below.

	Three Months Ended March 31 2016	Three Months Ended March 31 2015
	(In thousands)	
Commodity contracts	$ 4,594	$ (7,622)
Fair value adjustment for natural gas inventory designated as the hedged item	(7,939)	5,142
Total increase in purchased gas cost	$ (3,345)	$ (2,480)
The increase in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (2,095)	$ (678)
Timing ineffectiveness	(1,250)	(1,802)
	$ (3,345)	$ (2,480)

	Six Months Ended March 31	
	2016	2015
	(In thousands)	
Commodity contracts	$ 10,338	$ 7,469
Fair value adjustment for natural gas inventory designated as the hedged item	(5,778)	(11,641)
Total (increase) decrease in purchased gas cost	$ 4,560	$ (4,172)
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (806)	$ 309
Timing ineffectiveness	5,366	(4,481)
	$ 4,560	$ (4,172)

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

Cash Flow Hedges

The impact of cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 2016 and 2015 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Three Months Ended March 31, 2016		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (12,703)	$ (12,703)
Gain arising from ineffective portion of commodity contracts	—	61	61
Total impact on purchased gas cost	—	(12,642)	(12,642)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(136)	—	(136)
Total Impact from Cash Flow Hedges	$ (136)	$ (12,642)	$ (12,778)

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

	Six Months Ended March 31, 2016		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (35,668)	$ (35,668)
Gain arising from ineffective portion of commodity contracts	—	18	18
Total impact on purchased gas cost	—	(35,650)	(35,650)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(273)	—	(273)
Total Impact from Cash Flow Hedges	$ (273)	$ (35,650)	$ (35,923)

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

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 2016 and 2015. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended March 31		Six Months Ended March 31	
	2016	2015	2016	2015
		(In thousands)		
Decrease in fair value:				
Interest rate agreements	$ (53,704)	$ (32,755)	$ (49,008)	$ (84,824)
Forward commodity contracts	(7,529)	(10,160)	(19,185)	(38,902)
Recognition of losses in earnings due to settlements:				
Interest rate agreements	86	86	173	368
Forward commodity contracts	7,749	7,978	21,758	7,768
Total other comprehensive loss from hedging, net of tax[1]	$ (53,398)	$ (34,851)	$ (46,262)	$ (115,590)

(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 losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2016. 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)	$ (19,651)	$ (19,998)
Thereafter	(18,130)	(3,213)	(21,343)
Total[(1)]	$ (18,477)	$ (22,864)	$ (41,341)

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

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended March 31, 2016 and 2015 was an (increase) decrease in purchased gas cost of $(2.5) million and $8.7 million. For the six months ended March 31, 2016 and 2015 purchased gas cost (increased) decreased by $(4.7) million and $9.6 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.

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, 2015. During the six months ended March 31, 2016, 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, 2015.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2016 and September 30, 2015. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[(1)]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[(2)]	March 31, 2016
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 637	$ —	$ —	$ 637
Nonregulated segment	—	71,683	—	(64,846)	6,837
Total financial instruments	—	72,320	—	(64,846)	7,474
Hedged portion of gas stored underground	65,077	—	—	—	65,077
Available-for-sale securities					
Money market funds	—	4,400	—	—	4,400
Registered investment companies	36,670	—	—	—	36,670
Bonds	—	33,477	—	—	33,477
Total available-for-sale securities	36,670	37,877	—	—	74,547
Total assets	$ 101,747	$ 110,197	$ —	$ (64,846)	$ 147,098
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 188,501	$ —	$ (2,660)	$ 185,841
Nonregulated segment	—	87,768	—	(87,768)	—
Total liabilities	$ —	$ 276,269	$ —	$ (90,428)	$ 185,841

	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, 2015
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 746	$ —	$ —	$ 746
Nonregulated segment	—	91,363	—	(82,509)	8,854
Total financial instruments	—	92,109	—	(82,509)	9,600
Hedged portion of gas stored underground	43,901	—	—	—	43,901
Available-for-sale securities					
Money market funds	—	1,072	—	—	1,072
Registered investment companies	40,619	—	—	—	40,619
Bonds	—	32,509	—	—	32,509
Total available-for-sale securities	40,619	33,581	—	—	74,200
Total assets	$ 84,520	$ 125,690	$ —	$ (82,509)	$ 127,701
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 120,107	$ —	$ —	$ 120,107
Nonregulated segment	—	125,983	—	(125,983)	—
Total liabilities	$ —	$ 246,090	$ —	$ (125,983)	$ 120,107

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

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of March 31, 2016, we had $2.7 million of cash held in margin accounts to collateralize certain regulated distribution financial instruments, which were used to offset noncurrent risk management liabilities. As of March 31, 2016, we had $22.9 million of cash held in margin accounts to collateralize certain nonregulated financial instruments. Of this amount, $16.1 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $6.8 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, 2015, we had $43.5 million of cash held in margin accounts to collateralize certain nonregulated financial instruments. Of this amount, $34.6 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $8.9 million is classified as current risk management assets.

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

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of March 31, 2016				
Domestic equity mutual funds	$ 26,548	$ 5,425	$ (1,115)	$ 30,858
Foreign equity mutual funds	5,037	775	—	5,812
Bonds	33,355	132	(10)	33,477
Money market funds	4,400	—	—	4,400
	$ 69,340	$ 6,332	$ (1,125)	$ 74,547
As of September 30, 2015				
Domestic equity mutual funds	$ 27,643	$ 7,332	$ (456)	$ 34,519
Foreign equity mutual funds	5,261	905	(66)	6,100
Bonds	32,423	106	(20)	32,509
Money market funds	1,072	—	—	1,072
	$ 66,399	$ 8,343	$ (542)	$ 74,200

At March 31, 2016 and September 30, 2015, our available-for-sale securities included $41.1 million and $41.7 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At March 31, 2016, we maintained investments in bonds that have contractual maturity dates ranging from May 2016 through September 2020.

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

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of March 31, 2016 and September 30, 2015:

	March 31, 2016	September 30, 2015
	(In thousands)	
Carrying Amount	$ 2,460,000	$ 2,460,000
Fair Value	$ 2,749,244	$ 2,669,323

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, 2015. During the six months ended March 31, 2016, there were no material changes in our concentration of credit risk.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of March 31, 2016 and the related condensed consolidated statements of income and comprehensive income for the three and six-month periods ended March 31, 2016 and 2015 and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2016 and 2015. 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, 2015, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended, not presented herein, and we expressed an unqualified audit opinion on those consolidated financial statements in our report dated November 6, 2015. In our opinion, the accompanying condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2015, is fairly stated, in all material respects, in relation to the consolidated balance sheets from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
May 4, 2016

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, 2015.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit and capital 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 commodity price volatility, counterparty creditworthiness or performance and interest rate risk; 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 regulated distribution business; increased costs of providing health care benefits along with pension and postretirement health care benefits and increased funding requirements; the inability to continue to hire, train and retain appropriate personnel; 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 climate changes or related additional legislation or regulation in the future; the inherent hazards and risks involved in operating our distribution and pipeline and storage businesses; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six regulated distribution divisions, which at March 31, 2016 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 transmission 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, 2015 and include the following:

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

Our critical accounting policies are reviewed periodically by the Audit Committee of our Board of Directors. There were no significant changes to these critical accounting policies during the six months ended March 31, 2016.

RESULTS OF OPERATIONS

Executive Summary

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

During the first six months of fiscal 2016, we earned $244.7 million, or $2.38 per diluted share, a four percent increase period over period. Regulated operations represented 98 and 97 percent of our consolidated net income for the three and six months ended March 31, 2016. The following tables reflect the segregation of our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended March 31		
	2016	2015	Change
	(In thousands, except per share data)		
Regulated operations	$ 139,497	$ 129,535	$ 9,962
Nonregulated operations	2,313	8,149	(5,836)
Net income	$ 141,810	$ 137,684	$ 4,126
Diluted EPS from regulated operations	$ 1.36	$ 1.27	$ 0.09
Diluted EPS from nonregulated operations	0.02	0.08	(0.06)
Consolidated diluted EPS	$ 1.38	$ 1.35	$ 0.03

	Six Months Ended March 31		
	2016	2015	Change
	(In thousands, except per share data)		
Regulated operations	$ 238,338	$ 222,957	$ 15,381
Nonregulated operations	6,333	12,322	(5,989)
Net income	$ 244,671	$ 235,279	$ 9,392
Diluted EPS from regulated operations	$ 2.32	$ 2.19	$ 0.13
Diluted EPS from nonregulated operations	0.06	0.12	(0.06)
Consolidated diluted EPS	$ 2.38	$ 2.31	$ 0.07

Positive rate outcomes achieved in our regulated businesses offset the effect of weather that was 26 percent warmer than the prior-year period. As of March 31, 2016, we had completed nine regulatory proceedings resulting in a $22.1 million increase in annual operating income and had twelve ratemaking efforts in progress seeking $109.0 million of additional annual operating income. Our nonregulated results in the current-year period reflect larger losses on the settlement of financial positions during a period of falling gas prices.

Capital expenditures for the first six months of fiscal 2016 were $538.2 million. Approximately 83 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 $1 billion and $1.1 billion for fiscal 2016. We funded our capital expenditure program primarily through operating cash flows of $455.8 million and net short-term borrowings.

On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. The shares will be issued under our shelf registration statement filed with the SEC on March 28, 2016. Proceeds from the ATM program will be used primarily to repay short-term debt outstanding under our $1.25 billion commercial paper program, to fund capital spending primarily to enhance the safety and reliability of our system and for general corporate purposes.

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 7.7 percent for fiscal 2016.

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 includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

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

Three Months Ended March 31, 2016 compared with Three Months Ended March 31, 2015

Financial and operational highlights for our regulated distribution segment for the three months ended March 31, 2016 and 2015 are presented below.

	Three Months Ended March 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 409,142	$ 406,235	$ 2,907
Operating expenses	211,529	221,517	(9,988)
Operating income	197,613	184,718	12,895
Miscellaneous expense	(150)	(937)	787
Interest charges	18,717	19,313	(596)
Income before income taxes	178,746	164,468	14,278
Income tax expense	64,434	62,615	1,819
Net income	$ 114,312	$ 101,853	$ 12,459
Consolidated regulated distribution sales volumes — MMcf	111,932	142,455	(30,523)
Consolidated regulated distribution transportation volumes — MMcf	40,677	40,559	118
Total consolidated regulated distribution throughput — MMcf	152,609	183,014	(30,405)
Consolidated regulated distribution average cost of gas per Mcf sold	$ 3.94	$ 5.08	$ (1.14)

Income for our regulated distribution segment increased 12 percent, primarily due to a $2.9 million increase in gross profit combined with a $10.0 million decrease in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $17.1 million net increase in rate adjustments. Our Mid-Tex Division accounted for $9.8 million of this increase. We also experienced increases in our Mississippi and West Texas Divisions.
- a $12.6 million decrease in revenue-related taxes primarily in our Mid-Tex and West Texas Divisions, offset by a corresponding $10.4 million decrease in the related tax expense.
- a $2.2 million decrease in consumption. Current-quarter weather was 25 percent warmer than the prior-year quarter, before adjusting for weather normalization mechanisms. As a result, sales volumes decreased 21 percent.

The decrease in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to the decrease in revenue-related tax expense partially offset by higher 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 March 31, 2016 and 2015. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2016	2015	Change
	(In thousands)		
Mid-Tex	$ 80,645	$ 73,999	$ 6,646
Kentucky/Mid-States	30,461	29,356	1,105
Louisiana	23,742	24,094	(352)
West Texas	20,298	17,704	2,594
Mississippi	23,705	21,511	2,194
Colorado-Kansas	18,030	17,268	762
Other	732	786	(54)
Total	$ 197,613	$ 184,718	$ 12,895

Six Months Ended March 31, 2016 compared with Six Months Ended March 31, 2015

Financial and operational highlights for our regulated distribution segment for the six months ended March 31, 2016 and 2015 are presented below.

	Six Months Ended March 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 742,603	$ 730,047	$ 12,556
Operating expenses	405,473	407,232	(1,759)
Operating income	337,130	322,815	14,315
Miscellaneous expense	(902)	(2,266)	1,364
Interest charges	39,422	40,953	(1,531)
Income before income taxes	296,806	279,596	17,210
Income tax expense	109,239	106,356	2,883
Net income	$ 187,567	$ 173,240	$ 14,327
Consolidated regulated distribution sales volumes — MMcf	180,649	229,377	(48,728)
Consolidated regulated distribution transportation volumes — MMcf	72,888	77,071	(4,183)
Total consolidated regulated distribution throughput — MMcf	253,537	306,448	(52,911)
Consolidated regulated distribution average cost of gas per Mcf sold	$ 4.13	$ 5.44	$ (1.31)

Income for our regulated distribution segment increased eight percent, primarily due to a $12.6 million increase in gross profit combined with a $1.8 million decrease in operating expenses. The year-over-year increase in gross profit primarily reflects:

- a $30.6 million net increase in rate adjustments. Our Mid-Tex Division accounted for $16.9 million of this increase. We also experienced increases in our Mississippi and West Texas Divisions.
- a $13.9 million decrease in revenue-related taxes primarily in our Mid-Tex and West Texas Divisions, offset by a corresponding $10.8 million decrease in the related tax expense.
- a $3.3 million decrease in consumption. Current-period weather was 26 percent warmer than the prior-year period, before adjusting for weather normalization mechanisms. As a result, sales volumes decreased 21 percent.

The decrease in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to the decrease in revenue-related tax expense partially offset by increased property taxes and depreciation expense associated with increased capital investments.

Net income for the six months ended March 31, 2016 includes a $3.3 million income tax benefit for stock awards that vested during the current-year period as a result of adopting the new stock-based accounting guidance.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the six months ended March 31, 2016 and 2015. The presentation of our regulated distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2016	2015	Change
		(In thousands)	
Mid-Tex	$ 148,776	$ 133,113	$ 15,663
Kentucky/Mid-States	49,379	49,152	227
Louisiana	38,794	40,819	(2,025)
West Texas	33,228	28,802	4,426
Mississippi	36,532	35,810	722
Colorado-Kansas	28,156	27,257	899
Other	2,265	7,862	(5,597)
Total	$ 337,130	$ 322,815	$ 14,315

Recent Ratemaking Developments

The amounts described in the following sections represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling. During the first six months of fiscal 2016, we completed nine regulatory proceedings, resulting in a $22.1 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Annual formula rate mechanisms	$ 17,826
Rate case filings	4,456
Other rate activity	(183)
	$ 22,099

Additionally, the following ratemaking efforts seeking $68.3 million in annual operating income were in progress as of March 31, 2016:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	Rate Case	Kentucky	$ 5,531
Kentucky/Mid-States	Formula Rate Mechanism	Tennessee	4,888
Kentucky/Mid-States	Expedited Rate Filing[1]	Virginia	537
Louisiana	Formula Rate Mechanism[1]	Trans LA	6,216
Louisiana	Formula Rate Mechanism	LGS	8,686
Mid-Tex	Formula Rate Mechanism	Dallas	6,915
Mid-Tex	Formula Rate Mechanism	Mid-Tex Cities	26,564
Mid-Tex	Formula Rate Mechanism[2]	Environs	1,325
Mississippi	Infrastructure Mechanism	Mississippi	3,519
West Texas	Infrastructure Mechanism [3]	Cities of Amarillo, Channing, Lubbock & Dalhart	3,484
West Texas	Infrastructure Mechanism[2]	Environs	646
			$ 68,311

(1) The proposed increase for Virginia and Trans LA customers was implemented on April 1, 2016, subject to refund.

(2) The 2015 GRIP increase was approved by the Railroad Commission of Texas on May 3, 2016.

(3) The 2015 GRIP increase was implemented on April 26, 2016.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have formula rate mechanisms in our Louisiana, Mississippi and Tennessee operations and in substantially all of our Texas divisions. Additionally, we have specific infrastructure programs in substantially all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	Infrastructure Programs	Formula Rate Mechanisms
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following annual formula rate mechanisms were approved during the six months ended March 31, 2016.

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2016 Filings:				
Colorado-Kansas	Colorado	12/31/2016	$ 764	01/01/2016
Mississippi	Mississippi-SRF[(1)]	10/31/2016	9,192	01/01/2016
Mississippi	Mississippi-SGR [(2)]	10/31/2016	250	12/01/2015
Kentucky/Mid-States	Kentucky-PRP	09/30/2016	3,786	10/01/2015
Kentucky/Mid-States	Virginia-SAVE	09/30/2016	118	10/01/2015
West Texas	West Texas Cities	09/30/2015	3,716	10/01/2015
Total 2016 Filings			$ 17,826	

(1) The commission issued a final order approving a $9.2 million increase in annual operating income on December 21, 2015 with an effective date of January 1, 2016.

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

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 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 six months ended March 31, 2016.

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2016 Rate Case Filings:			
Colorado-Kansas	Kansas	$ 2,372	03/17/2016
Colorado-Kansas	Colorado	2,084	01/01/2016
Total 2016 Rate Case Filings		$ 4,456	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2016.

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2016 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem [(1)]	$ (183)	02/01/2016
Total 2016 Other Rate Activity			$ (183)	

(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 and stores natural gas for our Mid-Tex Division and third party local distribution companies and manages five underground storage facilities in Texas. We also provide interruptible transportation, storage and ancillary services to electric generation and industrial customers as well as producers, marketers and other shippers.

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 and storage 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 the volumes of gas transported for shippers through our pipeline system and the rates for such transportation.

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 transporter 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. Additionally, APT annually uses GRIP to recover capital costs incurred in the prior calendar year.

Three Months Ended March 31, 2016 compared with Three Months Ended March 31, 2015

Financial and operational highlights for our regulated pipeline segment for the three months ended March 31, 2016 and 2015 are presented below.

	Three Months Ended March 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 72,872	$ 60,666	$ 12,206
Third-party transportation	19,594	28,085	(8,491)
Storage and park and lend services	588	1,069	(481)
Other	2,649	1,910	739
Gross profit	95,703	91,730	3,973
Operating expenses	47,048	39,827	7,221
Operating income	48,655	51,903	(3,248)
Miscellaneous expense	(376)	(379)	3
Interest charges	9,145	8,391	754
Income before income taxes	39,134	43,133	(3,999)
Income tax expense	13,949	15,451	(1,502)
Net income	$ 25,185	$ 27,682	$ (2,497)
Gross pipeline transportation volumes — MMcf	185,542	220,646	(35,104)
Consolidated pipeline transportation volumes — MMcf	115,040	126,371	(11,331)

Net income for our regulated pipeline segment decreased nine percent, primarily due to a $4.0 million increase in gross profit, offset by a $7.2 million increase in operating expenses. The increase in gross profit primarily reflects a $7.0 million increase in rates from the GRIP filing approved in 2015 partially offset by decreased through-system volumes and lower storage and blending fees due to warmer weather in the current-year quarter compared to the prior-year quarter.

Operating expenses increased $7.2 million, primarily due to increased levels of pipeline maintenance activities to improve the safety and reliability of our system and increased property taxes and depreciation expense associated with increased capital investments.

On May 3, 2016, a GRIP filing was approved by the Railroad Commission of Texas for $40.7 million of additional annual operating income, effective with bills rendered on and after May 3, 2016.

Six Months Ended March 31, 2016 compared with Six Months Ended March 31, 2015

Financial and operational highlights for our regulated pipeline segment for the six months ended March 31, 2016 and 2015 are presented below.

	Six Months Ended March 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 141,159	$ 120,745	$ 20,414
Third-party transportation	40,882	48,479	(7,597)
Storage and park and lend services	1,564	2,073	(509)
Other	6,775	4,000	2,775
Gross profit	190,380	175,297	15,083
Operating expenses	92,477	80,689	11,788
Operating income	97,903	94,608	3,295
Miscellaneous expense	(805)	(631)	(174)
Interest charges	18,292	16,715	1,577
Income before income taxes	78,806	77,262	1,544
Income tax expense	28,035	27,545	490
Net income	$ 50,771	$ 49,717	$ 1,054
Gross pipeline transportation volumes — MMcf	363,744	402,008	(38,264)
Consolidated pipeline transportation volumes — MMcf	244,199	247,005	(2,806)

Net income for our regulated pipeline segment increased two percent, primarily due to a $15.1 million increase in gross profit, partially offset by an $11.8 million increase in operating expenses. The increase in gross profit primarily reflects a $17.1 million increase in rates from the GRIP filing approved in 2015 and a $3.1 million increase from the sale of excess retention gas. These increases were partially offset by decreased through-system volumes and lower storage and blending fees due to warmer weather in the current-year period compared to the prior-year period.

Operating expenses increased $11.8 million, primarily due to increased levels of pipeline maintenance activities to improve the safety and reliability of our system and increased property taxes and depreciation expense associated with increased capital investments.

Nonregulated Segment

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

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

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

Our nonregulated activities are significantly influenced by competitive factors in the industry and general economic conditions. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of buying, selling and delivering natural gas to offer more competitive pricing to those customers.

Natural gas prices can influence:

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

- The level of borrowings under our credit facilities, which affects the level of interest expense recognized by this segment.

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

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Increased or decreased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

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

Three Months Ended March 31, 2016 compared with Three Months Ended March 31, 2015

Financial and operating highlights for our nonregulated segment for the three months ended March 31, 2016 and 2015 are presented below.

	Three Months Ended March 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 16,705	$ 17,873	$ (1,168)
Storage and transportation services	3,272	3,353	(81)
Other	(3,514)	3,001	(6,515)
Total realized margins	16,463	24,227	(7,764)
Unrealized margins	(3,364)	(1,321)	(2,043)
Gross profit	13,099	22,906	(9,807)
Operating expenses	9,351	9,317	34
Operating income	3,748	13,589	(9,841)
Miscellaneous income	292	252	40
Interest charges	149	240	(91)
Income before income taxes	3,891	13,601	(9,710)
Income tax expense	1,578	5,452	(3,874)
Net income	$ 2,313	$ 8,149	$ (5,836)
Gross nonregulated delivered gas sales volumes — MMcf	107,414	122,178	(14,764)
Consolidated nonregulated delivered gas sales volumes — MMcf	95,804	105,401	(9,597)
Net physical position (Bcf)	36.4	17.0	19.4

The $9.8 million quarter-over-quarter decrease in gross profit reflects a $7.8 million decrease in realized margins, combined with a $2.0 million decrease in unrealized margins. The following were the key drivers for the $7.8 million decrease in realized margins:

- Margins from gas delivery and related services margins decreased $1.2 million, primarily due to a nine percent decrease in consolidated sales volumes due to warmer weather in the current-year quarter. However, this decrease was partially offset by an increase in per-unit margins from 15 cents to 16 cents per Mcf, primarily due to lower net transportation costs incurred as result of fewer deliveries.
- Other realized margins decreased $6.5 million. The decrease primarily reflects higher losses, compared with the prior-year quarter, on the settlement of long financial positions as a result of falling natural gas prices during the quarter. Additionally, storage fees increased quarter-over-quarter due to increased park and loan activity.

Unrealized margins decreased $2.0 million, primarily due to the quarter-over-quarter unfavorable movement of the physical mark on the fair value of natural gas inventory hedged positions.

Six Months Ended March 31, 2016 compared with Six Months Ended March 31, 2015

	Six Months Ended March 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 28,555	$ 28,632	$ (77)
Storage and transportation services	6,527	6,666	(139)
Other	(14,765)	(2,830)	(11,935)
Total realized margins	20,317	32,468	(12,151)
Unrealized margins	8,540	6,477	2,063
Gross profit	28,857	38,945	(10,088)
Operating expenses	17,669	18,433	(764)
Operating income	11,188	20,512	(9,324)
Miscellaneous income	671	552	119
Interest charges	1,187	466	721
Income before income taxes	10,672	20,598	(9,926)
Income tax expense	4,339	8,276	(3,937)
Net income	$ 6,333	$ 12,322	$ (5,989)
Gross nonregulated delivered gas sales volumes — MMcf	204,147	230,371	(26,224)
Consolidated nonregulated delivered gas sales volumes — MMcf	180,935	196,331	(15,396)
Net physical position (Bcf)	36.4	17.0	19.4

The $10.1 million year-over-year decrease in gross profit reflects a $12.2 million decrease in realized margins, partially offset by a $2.1 million increase in unrealized margins. The following were the key drivers for the $12.2 million decrease in realized margins:

- Margins from gas delivery and related services were flat year-over-year. Consolidated sales volumes decreased eight percent due to warmer weather. However, lower net transportation costs and other variable costs driven by fewer deliveries resulted in an increase in per-unit margins from 12 cents to 14 cents per Mcf, which offset the effect of reduced sales volumes.
- Other realized margins decreased $11.9 million. The decrease primarily reflects higher losses, compared with the prior-year period, on the settlement of long financial positions as a result of falling natural gas prices. Additionally, storage fees increased period-over-period due to increased park and loan activity.

Unrealized margins increased $2.1 million, primarily due to the period-over-period favorable movement of the physical mark on the fair value of natural gas inventory hedged positions.

Operating expenses decreased $0.8 million, primarily due to lower bad debt expense.

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 45 to 55 percent. We also evaluate the levels of committed borrowing capacity that we require. We currently have over $1 billion of capacity under 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 filed a registration statement with the SEC on March 28, 2016 to issue, from time to time, up to $2.5 billion in common stock and/or debt securities, which replaced our registration statement that expired on March 28, 2016. On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. The shares will be issued under our shelf registration statement. Proceeds from the ATM program will be used primarily to repay short-term debt outstanding under our $1.25 billion commercial paper program, to fund capital spending primarily to enhance the safety and reliability of our system and for general corporate purposes. No shares were issued under the ATM program during the second fiscal quarter of 2016.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2016, September 30, 2015 and March 31, 2015:

	March 31, 2016		September 30, 2015		March 31, 2015	
	(In thousands, except percentages)					
Short-term debt	$ 626,929	9.8%	$ 457,927	7.5%	$ 224,986	3.9%
Long-term debt	2,455,559	38.2%	2,455,388	40.2%	2,455,217	42.2%
Shareholders' equity	3,344,565	52.0%	3,194,797	52.3%	3,139,694	53.9%
Total	$ 6,427,053	100.0%	$ 6,108,112	100.0%	$ 5,819,897	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 six months ended March 31, 2016 and 2015 are presented below.

	Six Months Ended March 31 2016	2015	Change
	(In thousands)		
Total cash provided by (used in)			
Operating activities	$ 455,776	$ 540,848	$ (85,072)
Investing activities	(536,345)	(442,990)	(93,355)
Financing activities	99,834	(44,591)	144,425
Change in cash and cash equivalents	19,265	53,267	(34,002)
Cash and cash equivalents at beginning of period	28,653	42,258	(13,605)
Cash and cash equivalents at end of period	$ 47,918	$ 95,525	$ (47,607)

Cash flows from operating activities

Period-over-period changes in our operating cash flows are primarily attributable to changes in net income and working capital changes, particularly within our regulated distribution segment resulting from changes in the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the six months ended March 31, 2016, we generated cash flow of $455.8 million from operating activities compared with $540.8 million for the six months ended March 31, 2015. The $85.1 million decrease in operating cash flows primarily reflects the timing of deferred gas cost recoveries.

Cash flows from investing activities

In executing our regulatory strategy, we target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions 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 our ongoing construction program, which 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. Over the last three fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system. We anticipate our annual capital spending will be in the range of $1 billion to $1.1 billion through fiscal 2020.

For the six months ended March 31, 2016, capital expenditures were $538.2 million, compared with $441.6 million in the prior-year period. The $96.6 million increase primarily reflects an 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 combined with a planned increase in spending in our regulated distribution operations.

Cash flows from financing activities

For the six months ended March 31, 2016, our financing activities generated $99.8 million of cash compared with $44.6 million of cash used in the prior-year period. The $144.4 million increase of cash generated is primarily due to higher net short-term debt borrowings due to increased capital expenditures and period-over-period changes in working capital funding needs compared to the prior year.

The following table summarizes our share issuances for the six months ended March 31, 2016 and 2015.

	Six Months Ended March 31	
	2016	**2015**
Shares issued:		
Direct Stock Purchase Plan	78,652	79,803
1998 Long-Term Incentive Plan	458,929	488,729
Retirement Savings Plan and Trust	193,106	178,067
Total shares issued	730,687	746,599

The year-over-year decrease in the number of shares issued primarily reflects a decrease in shares issued under the 1998 Long-Term Incentive Plan. For the six months ended March 31, 2016, we did not cancel and retire any shares attributable to federal income tax withholdings on equity awards. For the six months ended March 31, 2015, we canceled and retired 148,464 such shares.

Credit Facilities

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

We finance our short-term borrowing requirements through a combination of a $1.25 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.3 billion of working capital funding. As of March 31, 2016, the amount available to us under our credit facilities, net of commercial paper and outstanding letters of credit, was $0.7 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 March 31, 2016, Moody's and Fitch maintained a stable outlook. S&P issued a revised outlook from stable to positive on October 29, 2015, citing the potential for an upgraded rating in the future if we maintain our current level of financial performance as capital spending levels remain elevated. 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
Short-term debt	A-2	P-1	F-2

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of March 31, 2016. Our debt covenants are described in greater detail in Note 5 to the unaudited condensed consolidated financial statements.

Contractual Obligations and Commercial Commitments

Except as noted in Note 7 to the unaudited condensed consolidated financial statements, there were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2016.

Risk Management Activities

We conduct risk management activities through our regulated distribution and nonregulated segments. In our regulated distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

In our nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our regulated distribution segment's financial instruments for the three and six months ended March 31, 2016 and 2015:

	Three Months Ended March 31		Six Months Ended March 31	
	2016	2015	2016	2015
	(In thousands)			
Fair value of contracts at beginning of period	$ (109,263)	$ (94,848)	$ (119,361)	$ 14,284
Contracts realized/settled	(8,128)	(10,655)	(20,758)	(33,811)
Fair value of new contracts	240	216	57	(149)
Other changes in value	(70,713)	(32,423)	(47,802)	(118,034)
Fair value of contracts at end of period	(187,864)	(137,710)	(187,864)	(137,710)
Netting of cash collateral	2,660	—	2,660	—
Cash collateral and fair value of contracts at period end	$ (185,204)	$ (137,710)	$ (185,204)	$ (137,710)

The fair value of our regulated distribution segment's financial instruments at March 31, 2016 is presented below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at March 31, 2016 Maturity in Years Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
			(In thousands)		
Prices actively quoted	$ (147)	$ (187,717)	$ —	$ —	$ (187,864)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (147)	$ (187,717)	$ —	$ —	$ (187,864)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and six months ended March 31, 2016 and 2015:

	Three Months Ended March 31		Six Months Ended March 31	
	2016	2015	2016	2015
		(In thousands)		
Fair value of contracts at beginning of period	$ (21,019)	$ (26,099)	$ (34,620)	$ (3,033)
Contracts realized/settled	1,849	4,346	20,747	11,511
Fair value of new contracts	—	—	—	—
Other changes in value	3,085	(14,387)	(2,212)	(44,618)
Fair value of contracts at end of period	(16,085)	(36,140)	(16,085)	(36,140)
Netting of cash collateral	22,922	52,723	22,922	52,723
Cash collateral and fair value of contracts at period end	$ 6,837	$ 16,583	$ 6,837	$ 16,583

The fair value of our nonregulated segment's financial instruments at March 31, 2016 is presented below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at March 31, 2016 Maturity in Years Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
			(In thousands)		
Prices actively quoted	$ (14,503)	$ (2,047)	$ 465	$ —	$ (16,085)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (14,503)	$ (2,047)	$ 465	$ —	$ (16,085)

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2016 and 2015, our total net periodic pension and other benefits costs were $23.0 million and $29.4 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 2016 costs were determined using a September 30, 2015 measurement date. As of September 30, 2015, interest and corporate bond rates utilized to determine our discount rates were higher than the interest and corporate bond rates as of September 30, 2014, the measurement date for our fiscal 2015 net periodic cost. Therefore, we increased the discount rate used to measure our fiscal 2016 net periodic cost from 4.43 percent to 4.55 percent. We lowered our expected return on plan assets from 7.25 percent to 7.00 percent in the determination of our fiscal 2016 net periodic pension cost based upon expected market returns for our targeted asset allocation. 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 and in October 2015, the Society of Actuaries issued an additional report related to mortality tables and the mortality improvement scale. As of September 30, 2015, we updated our assumed mortality tables to incorporate both of these updates. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2016 net periodic pension cost to decrease by approximately 20 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 the determination as of January 1, 2015, we are not required to make a minimum contribution to our defined benefit plans during fiscal 2016. However, we may consider whether a voluntary contribution is prudent to maintain certain funding levels.

For the six months ended March 31, 2016 we contributed $9.0 million to our postretirement medical plans. We anticipate contributing between $15 million and $25 million to our postretirement plans during fiscal 2016.

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

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our regulated distribution, regulated pipeline and nonregulated segments for the three and six month periods ended March 31, 2016 and 2015.

Regulated Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2016	2015	2016	2015
METERS IN SERVICE, end of period				
Residential	2,899,265	2,864,252	2,899,265	2,864,252
Commercial	267,213	262,235	267,213	262,235
Industrial	1,479	1,524	1,479	1,524
Public authority and other	8,410	8,430	8,410	8,430
Total meters	3,176,367	3,136,441	3,176,367	3,136,441
INVENTORY STORAGE BALANCE — Bcf	40.2	25.0	40.2	25.0
SALES VOLUMES — MMcf[1]				
Gas sales volumes				
Residential	68,758	90,182	108,927	142,400
Commercial	35,854	43,921	59,272	72,636
Industrial	4,459	4,898	7,915	8,788
Public authority and other	2,861	3,454	4,535	5,553
Total gas sales volumes	111,932	142,455	180,649	229,377
Transportation volumes	43,986	44,441	79,110	83,276
Total throughput	155,918	186,896	259,759	312,653
OPERATING REVENUES (000's)[1]				
Gas sales revenues				
Residential	$ 563,565	$ 744,013	$ 979,550	$ 1,285,738
Commercial	222,480	309,648	394,505	551,278
Industrial	17,568	26,694	31,853	49,605
Public authority and other	16,560	22,892	27,093	37,890
Total gas sales revenues	820,173	1,103,247	1,433,001	1,924,511
Transportation revenues	22,624	21,977	42,105	41,129
Other gas revenues	6,888	5,389	13,181	11,745
Total operating revenues	$ 849,685	$ 1,130,613	$ 1,488,287	$ 1,977,385
Average cost of gas per Mcf sold	$ 3.94	$ 5.08	$ 4.13	$ 5.44

See footnote following these tables.

Regulated Pipeline and Nonregulated Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2016	2015	2016	2015
CUSTOMERS, end of period				
Industrial	764	750	764	750
Municipal	133	130	133	130
Other	488	522	488	522
Total	1,385	1,402	1,385	1,402
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	35.1	18.5	35.1	18.5
REGULATED PIPELINE VOLUMES — MMcf(1)	185,542	220,646	363,744	402,008
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf(1)	107,414	122,178	204,147	230,371
OPERATING REVENUES (000's)(1)				
Regulated pipeline	$ 95,703	$ 91,730	$ 190,380	$ 175,297
Nonregulated	287,395	438,322	559,919	900,610
Total operating revenues	$ 383,098	$ 530,052	$ 750,299	$ 1,075,907

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, 2015. During the six months ended March 31, 2016, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of March 31, 2016 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the six months ended March 31, 2016, 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, 2015. We continue to believe that the final outcome of such litigation and other matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 6. *Exhibits*

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

SIGNATURE

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

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and
Chief Financial Officer
(Duly authorized signatory)

Date: May 4, 2016

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
10	Equity Distribution Agreement, dated as of March 28, 2016, among Atmos Energy Corporation, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC.	Exhibit 1.1 to Form 8-K dated March 28, 2016 (File No. 1-10042)
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.

CASE NO. 2017-00349
FR 16(7)(p)
ATTACHMENT 3

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2016

or

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

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of July 29, 2016 .

Class	**Shares Outstanding**
No Par Value	103,847,858

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, 2016	September 30, 2015
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 9,972,415	$ 9,240,100
Less accumulated depreciation and amortization	1,918,868	1,809,520
Net property, plant and equipment	8,053,547	7,430,580
Current assets		
Cash and cash equivalents	66,206	28,653
Accounts receivable, net	277,362	295,160
Gas stored underground	244,841	236,603
Other current assets	60,504	65,890
Total current assets	648,913	626,306
Goodwill	742,702	742,702
Deferred charges and other assets	282,206	293,357
	$ 9,727,368	$ 9,092,945
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, 2016 — 103,827,358 shares; September 30, 2015 — 101,478,818 shares	$ 519	$ 507
Additional paid-in capital	2,371,381	2,230,591
Accumulated other comprehensive loss	(178,233)	(109,330)
Retained earnings	1,273,057	1,073,029
Shareholders' equity	3,466,724	3,194,797
Long-term debt	2,205,645	2,455,388
Total capitalization	5,672,369	5,650,185
Current liabilities		
Accounts payable and accrued liabilities	198,882	238,942
Other current liabilities	410,452	457,954
Short-term debt	670,466	457,927
Current maturities of long-term debt	250,000	—
Total current liabilities	1,529,800	1,154,823
Deferred income taxes	1,585,500	1,411,315
Regulatory cost of removal obligation	427,332	427,553
Pension and postretirement liabilities	283,579	287,373
Deferred credits and other liabilities	228,788	161,696
	$ 9,727,368	$ 9,092,945

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2016	2015
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 414,226	$ 416,794
Regulated pipeline segment	109,249	97,008
Nonregulated segment	214,555	278,769
Intersegment eliminations	(105,114)	(106,170)
	632,916	686,401
Purchased gas cost		
Regulated distribution segment	138,845	149,775
Regulated pipeline segment	—	—
Nonregulated segment	191,741	260,990
Intersegment eliminations	(104,981)	(106,037)
	225,605	304,728
Gross profit	407,311	381,673
Operating expenses		
Operation and maintenance	137,444	132,447
Depreciation and amortization	73,459	68,444
Taxes, other than income	59,244	63,175
Total operating expenses	270,147	264,066
Operating income	137,164	117,607
Miscellaneous income	833	634
Interest charges	27,698	27,955
Income before income taxes	110,299	90,286
Income tax expense	39,106	34,005
Net income	$ 71,193	$ 56,281
Basic and diluted net income per share	$ 0.69	$ 0.55
Cash dividends per share	$ 0.42	$ 0.39
Basic and diluted weighted average shares outstanding	103,750	102,000

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2016	2015
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Regulated distribution segment	$ 1,902,513	$ 2,394,179
Regulated pipeline segment	299,629	272,305
Nonregulated segment	774,474	1,179,379
Intersegment eliminations	(305,186)	(360,629)
	2,671,430	3,485,234
Purchased gas cost		
Regulated distribution segment	884,529	1,397,113
Regulated pipeline segment	—	—
Nonregulated segment	722,803	1,122,655
Intersegment eliminations	(304,787)	(360,230)
	1,302,545	2,159,538
Gross profit	1,368,885	1,325,696
Operating expenses		
Operation and maintenance	395,958	384,489
Depreciation and amortization	216,670	204,059
Taxes, other than income	172,872	181,606
Total operating expenses	785,500	770,154
Operating income	583,385	555,542
Miscellaneous expense	(1,061)	(2,634)
Interest charges	85,741	85,166
Income before income taxes	496,583	467,742
Income tax expense	180,719	176,182
Net income	$ 315,864	$ 291,560
Basic and diluted net income per share	$ 3.06	$ 2.86
Cash dividends per share	$ 1.26	$ 1.17
Basic and diluted weighted average shares outstanding	103,137	101,776

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	
	2016	2015	2016	2015
	(Unaudited) (In thousands)			
Net income	$ 71,193	$ 56,281	$ 315,864	$ 291,560
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $110, $(41), $(837) and $(170)	151	(191)	(1,496)	(296)
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(22,561), $31,314, $(50,631) and $(17,232)	(39,250)	54,475	(88,085)	(29,981)
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $11,575, $7,393, $13,220 and $(12,698)	18,105	11,563	20,678	(19,571)
Total other comprehensive income (loss)	(20,994)	65,847	(68,903)	(49,848)
Total comprehensive income	$ 50,199	$ 122,128	$ 246,961	$ 241,712

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2016	2015
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 315,864	$ 291,560
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization:		
Charged to depreciation and amortization	216,670	204,059
Charged to other accounts	983	853
Deferred income taxes	171,042	164,627
Other	19,767	18,146
Net assets / liabilities from risk management activities	(8,357)	(13,136)
Net change in operating assets and liabilities	(91,371)	51,473
Net cash provided by operating activities	624,598	717,582
Cash Flows From Investing Activities		
Capital expenditures	(796,008)	(667,483)
Other, net	1,627	(1,119)
Net cash used in investing activities	(794,381)	(668,602)
Cash Flows From Financing Activities		
Net increase in short-term debt	212,539	48,830
Net proceeds from equity offering	98,660	—
Issuance of common stock through stock purchase and employee retirement plans	26,500	20,813
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	(130,363)	(116,645)
Repurchase of equity awards	—	(7,985)
Net cash provided by (used in) financing activities	207,336	(48,085)
Net increase in cash and cash equivalents	37,553	895
Cash and cash equivalents at beginning of period	28,653	42,258
Cash and cash equivalents at end of period	$ 66,206	$ 43,153

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2016

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, 2016 , 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, 2015 . 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, 2015 . Because of seasonal and other factors, the results of operations for the nine -month period ended June 30, 2016 are not indicative of our results of operations for the full 2016 fiscal year, which ends September 30, 2016 .

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, 2015 .

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

During the second quarter of fiscal 2016, 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. 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. As of June 30, 2016 , we were actively evaluating all of our sources of revenue to determine the potential effect on our financial position, results of operations and cash flows and the transition approach we will utilize. We are also actively monitoring the deliberations of the FASB's Transition Resource Group as decisions made by this group will impact the final conclusions of this evaluation.

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.

In November 2015, the FASB issued guidance that requires all deferred income tax liabilities and assets to be presented as noncurrent in a classified balance sheet. Currently, entities are required to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified balance sheet. As permitted under the new guidance, we elected early adoption as of March 31, 2016. The adoption of this guidance had no impact on our results of operations or cash flows. Because we adopted this new guidance prospectively, prior periods have not been adjusted.

In January 2016, the FASB issued guidance related to the classification and measurement of financial instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning October 1, 2018; limited early adoption is permitted. We are currently evaluating the potential impact of this new guidance.

In February 2016, the FASB issued a comprehensive new leasing standard that will require lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The new standard will be effective for us beginning on October 1, 2019; early adoption is permitted. The new leasing standard requires modified retrospective transition, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. We are currently evaluating the effect on our financial position, results of operations and cash flows.

In March 2016, the FASB issued guidance to simplify the accounting and reporting of share-based payment arrangements. Key modifications required under the new guidance include:

- Recognition of all excess tax benefits and tax deficiencies associated with stock-based compensation as income tax expense or benefit in the income statement in the period the awards vest. The guidance also requires these income tax inflows and outflows to be classified as an operating activity.
- Simplification of the accounting for forfeitures.
- Clarification that cash paid by an employer when directly withholding shares for tax-withholding purposes should be classified as a financing activity.

As permitted under the new guidance, we elected early adoption as of March 31, 2016. In accordance with the transition requirements, we recorded a $3.3 million income tax benefit during the first six months of fiscal 2016. Additionally, we recorded a $14.5 million cumulative-effect increase to retained earnings with an offsetting increase to the Company's net operating loss (NOL) deferred tax asset to recognize the effect of excess tax benefits earned prior to September 30, 2015. For the nine months ended June 30, 2016, we have recognized a total income tax benefit of $4.9 million . Since we have adopted this new guidance prospectively, prior periods have not been adjusted.

In June 2016, the FASB issued new guidance which will require credit losses on most financial assets measured at amortized cost and certain other instruments to be measured using an expected credit loss model. Under this model, entities will estimate credit losses over the entire contractual term of the instrument from the date of initial recognition of that instrument. In contrast, current U.S. GAAP is based on an incurred loss model that delays recognition of credit losses until it is probable the loss has been incurred. The new guidance also introduces a new impairment recognition model for available-for-sale securities that will require credit losses for available-for-sale debt securities to be recorded through an allowance account. The new standard will be effective for us beginning on October 1, 2021; early adoption is permitted beginning on October 1, 2019. We are currently evaluating the potential impact of this new guidance.

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, 2016 and September 30, 2015 included the following:

	June 30, 2016	September 30, 2015
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs [(1)]	$ 110,425	$ 121,183
Infrastructure mechanisms [(2)]	31,090	32,813
Deferred gas costs	3,390	9,715
Recoverable loss on reacquired debt	14,401	16,319
APT annual adjustment mechanism	2,976	1,002
Rate case costs	1,640	1,533
Other	20,906	9,774
	$ 184,828	$ 192,339
Regulatory liabilities:		
Regulatory cost of removal obligations	$ 486,290	$ 483,676
Deferred gas costs	34,362	28,100
Asset retirement obligations	9,063	9,063
Other	5,483	3,693
	$ 535,198	$ 524,532

(1) Includes $12.9 million and $16.6 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, which primarily consist of interest, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

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, 2015 . We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and nine months ended June 30, 2016 and 2015 by segment are presented in the following tables:

	Three Months Ended June 30, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 411,982	$ 28,518	$ 192,416	$ —	$ 632,916
Intersegment revenues	2,244	80,731	22,139	(105,114)	—
	414,226	109,249	214,555	(105,114)	632,916
Purchased gas cost	138,845	—	191,741	(104,981)	225,605
Gross profit	275,381	109,249	22,814	(133)	407,311
Operating expenses					
Operation and maintenance	100,859	29,083	7,635	(133)	137,444
Depreciation and amortization	58,916	13,409	1,134	—	73,459
Taxes, other than income	52,377	6,220	647	—	59,244
Total operating expenses	212,152	48,712	9,416	(133)	270,147
Operating income	63,229	60,537	13,398	—	137,164
Miscellaneous income (expense)	1,111	(359)	574	(493)	833
Interest charges	18,968	9,002	221	(493)	27,698
Income before income taxes	45,372	51,176	13,751	—	110,299
Income tax expense	15,516	18,046	5,544	—	39,106
Net income	$ 29,856	$ 33,130	$ 8,207	$ —	$ 71,193
Capital expenditures	$ 191,202	$ 66,639	$ (66)	$ —	$ 257,775

	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

	Nine Months Ended June 30, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,896,636	$ 75,344	$ 699,450	$ —	$ 2,671,430
Intersegment revenues	5,877	224,285	75,024	(305,186)	—
	1,902,513	299,629	774,474	(305,186)	2,671,430
Purchased gas cost	884,529	—	722,803	(304,787)	1,302,545
Gross profit	1,017,984	299,629	51,671	(399)	1,368,885
Operating expenses					
Operation and maintenance	291,388	83,302	21,667	(399)	395,958
Depreciation and amortization	173,913	39,358	3,399	—	216,670
Taxes, other than income	152,324	18,529	2,019	—	172,872
Total operating expenses	617,625	141,189	27,085	(399)	785,500
Operating income	400,359	158,440	24,586	—	583,385
Miscellaneous income (expense)	209	(1,164)	1,245	(1,351)	(1,061)
Interest charges	58,390	27,294	1,408	(1,351)	85,741
Income before income taxes	342,178	129,982	24,423	—	496,583
Income tax expense	124,755	46,081	9,883	—	180,719
Net income	$ 217,423	$ 83,901	$ 14,540	$ —	$ 315,864
Capital expenditures	$ 533,826	$ 262,058	$ 124	$ —	$ 796,008

	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

Balance sheet information at June 30, 2016 and September 30, 2015 by segment is presented in the following tables:

	June 30, 2016				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$ 6,067,548	$ 1,935,087	$ 50,912	$ —	$ 8,053,547
Investment in subsidiaries	1,007,787	—	—	(1,007,787)	—
Current assets					
Cash and cash equivalents	61,441	—	4,765	—	66,206
Assets from risk management activities	3,651	—	4,047	—	7,698
Other current assets	370,444	22,269	391,265	(208,969)	575,009
Intercompany receivables	981,651	—	—	(981,651)	—
Total current assets	1,417,187	22,269	400,077	(1,190,620)	648,913
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	750	—	908	—	1,658
Deferred charges and other assets	258,370	21,976	202	—	280,548
	$ 9,327,091	$ 2,111,874	$ 486,810	$ (2,198,407)	$ 9,727,368
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,466,724	$ 661,175	$ 346,612	$ (1,007,787)	$ 3,466,724
Long-term debt	2,205,645	—	—	—	2,205,645
Total capitalization	5,672,369	661,175	346,612	(1,007,787)	5,672,369
Current liabilities					
Current maturities of long-term debt	250,000	—	—	—	250,000
Short-term debt	870,466	—	—	(200,000)	670,466
Liabilities from risk management activities	56,883	—	—	—	56,883
Other current liabilities	453,831	16,590	90,999	(8,969)	552,451
Intercompany payables	—	953,683	27,968	(981,651)	—
Total current liabilities	1,631,180	970,273	118,967	(1,190,620)	1,529,800
Deferred income taxes	1,093,755	480,336	11,409	—	1,585,500
Noncurrent liabilities from risk management activities	176,491	—	—	—	176,491
Regulatory cost of removal obligation	427,332	—	—	—	427,332
Pension and postretirement liabilities	283,579	—	—	—	283,579
Deferred credits and other liabilities	42,385	90	9,822	—	52,297
	$ 9,327,091	$ 2,111,874	$ 486,810	$ (2,198,407)	$ 9,727,368

	September 30, 2015				
	Regulated Distribution	Regulated Pipeline	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 5,670,306	$ 1,706,449	$ 53,825	$ —	$ 7,430,580
Investment in subsidiaries	1,038,670	—	(2,096)	(1,036,574)	—
Current assets					
Cash and cash equivalents	23,863	—	4,790	—	28,653
Assets from risk management activities	378	—	8,854	—	9,232
Other current assets	421,591	24,628	480,503	(338,301)	588,421
Intercompany receivables	887,713	—	—	(887,713)	—
Total current assets	1,333,545	24,628	494,147	(1,226,014)	626,306
Goodwill	575,449	132,542	34,711	—	742,702
Noncurrent assets from risk management activities	368	—	—	—	368
Deferred charges and other assets	270,372	17,288	5,329	—	292,989
	$ 8,888,710	$ 1,880,907	$ 585,916	$ (2,262,588)	$ 9,092,945
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,194,797	$ 577,275	$ 461,395	$ (1,038,670)	$ 3,194,797
Long-term debt	2,455,388	—	—	—	2,455,388
Total capitalization	5,650,185	577,275	461,395	(1,038,670)	5,650,185
Current liabilities					
Short-term debt	782,927	—	—	(325,000)	457,927
Liabilities from risk management activities	9,568	—	—	—	9,568
Other current liabilities	569,273	29,780	99,480	(11,205)	687,328
Intercompany payables	—	867,409	20,304	(887,713)	—
Total current liabilities	1,361,768	897,189	119,784	(1,223,918)	1,154,823
Deferred income taxes	1,008,091	406,254	(3,030)	—	1,411,315
Noncurrent liabilities from risk management activities	110,539	—	—	—	110,539
Regulatory cost of removal obligation	427,553	—	—	—	427,553
Pension and postretirement liabilities	287,373	—	—	—	287,373
Deferred credits and other liabilities	43,201	189	7,767	—	51,157
	$ 8,888,710	$ 1,880,907	$ 585,916	$ (2,262,588)	$ 9,092,945

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, 2016 and 2015 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(In thousands, except per share amounts)			
Basic and Diluted Earnings Per Share				
Net income	$ 71,193	$ 56,281	$ 315,864	$ 291,560
Less: Income allocated to participating securities	108	111	496	596
Income available to common shareholders	$ 71,085	$ 56,170	$ 315,368	$ 290,964
Basic and diluted weighted average shares outstanding	103,750	102,000	103,137	101,776
Net income per share - Basic and Diluted	$ 0.69	$ 0.55	$ 3.06	$ 2.86

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, 2015 . Except as noted below, there were no material changes in the terms of our debt instruments during the nine months ended June 30, 2016 .

Long-term debt

Long-term debt at June 30, 2016 and September 30, 2015 consisted of the following:

	June 30, 2016	September 30, 2015
	(In thousands)	
Unsecured 6.35% Senior Notes, due June 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	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	4,355	4,612
Current maturities	250,000	—
	$ 2,205,645	$ 2,455,388

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, 2016 and September 30, 2015 a total of $670.5 million and $457.9 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, which was renewed on April 1, 2016, and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under our $10 million revolving credit facility was $4.1 million at June 30, 2016 .

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, 2016.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, has one uncommitted $25 million bilateral credit facility that was renewed and extended in March 2016 and one committed $15 million bilateral credit facility that was renewed and extended in December 2015. The uncommitted $25 million bilateral credit facility currently expires in December 2016 and the $15 million bilateral credit facility expires in September 2016. These facilities are used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under these bilateral credit facilities was $33.0 million at June 30, 2016 .

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, 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, 2016 , our total-debt-to-total-capitalization ratio, as defined in the agreements, was 49 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, 2016 . 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. Shareholders' Equity

Shelf Registration

On March 28, 2016, we filed a registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue, from time to time, up to $2.5 billion in common stock and/or debt securities, which replaced our registration statement that expired on March 28, 2016. At June 30, 2016 , $2.4 billion of securities remain available for issuance under the shelf registration statement.

At-the-Market Equity Sales Program

On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement (the Agreement) with Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC in their capacity as agents and/or as principals (Agents). Under the terms of the Agreement, we may issue and sell, through any of the Agents, shares of our common stock, up to an aggregate offering price of $200 million , through the period ended March 28, 2019. We may also sell shares from time to time to an Agent for its own account at a price to be agreed upon at the time of sale. We will pay each Agent a commission of 1.0% of the gross offering proceeds of the shares sold through it as a sales agent. We have no obligation to offer or sell any shares under the Agreement, and may at any time suspend offers and sales under the Agreement. The shares will be issued pursuant to our shelf registration statement filed with the SEC on March 28, 2016. During the third fiscal quarter of 2016, we sold 1,360,756 shares of common stock under the ATM program for $100.0 million and received net proceeds of $98.7 million .

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan (LTIP), which became effective in October 1998 after approval by our shareholders. The LTIP is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

As of September 30, 2015, we were authorized to grant awards for up to a maximum of 8.7 million shares of common stock under this plan subject to certain adjustment provisions. In February 2016, our shareholders voted to increase the number of authorized LTIP shares by 2.5 million shares and to extend the term of the plan for an additional five years, through September 2021. On March 29, 2016, we filed with the SEC a registration statement on Form S-8 to register an additional 2.5 million shares; we also listed such shares with the New York Stock Exchange.

2011 Share Repurchase Program

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

Accumulated Other Comprehensive Income (Loss)

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 (loss).

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2015	$ 4,949	$ (88,842)	$ (25,437)	$ (109,330)
Other comprehensive loss before reclassifications	(1,417)	(88,345)	(8,612)	(98,374)
Amounts reclassified from accumulated other comprehensive income	(79)	260	29,290	29,471
Net current-period other comprehensive income (loss)	(1,496)	(88,085)	20,678	(68,903)
June 30, 2016	$ 3,453	$ (176,927)	$ (4,759)	$ (178,233)

	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)

The following tables detail reclassifications out of AOCI for the three and nine months ended June 30, 2016 and 2015 . Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended June 30, 2016	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$ (137)	Interest charges
Commodity contracts	(12,347)	Purchased gas cost
	(12,484)	Total before tax
	4,865	Tax benefit
Total reclassifications	$ (7,619)	Net of tax

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	Nine Months Ended June 30, 2016		
	Amount Reclassified from Accumulated Other Comprehensive Income		Affected Line Item in the Statement of Income
	(In thousands)		
Available-for-sale securities	$	124	Operation and maintenance expense
		124	Total before tax
		(45)	Tax expense
	$	79	Net of tax
Cash flow hedges			
Interest rate agreements	$	(410)	Interest charges
Commodity contracts		(48,015)	Purchased gas cost
		(48,425)	Total before tax
		18,875	Tax benefit
	$	(29,550)	Net of tax
Total reclassifications	$	(29,471)	Net of tax

Accumulated Other Comprehensive Income Components	Nine 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	$	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

7. 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, 2016 and 2015 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.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 4,698	$ 5,051	$ 2,705	$ 3,895
Interest cost	7,095	6,698	3,106	3,596
Expected return on assets	(6,881)	(6,435)	(1,566)	(1,608)
Amortization of transition obligation	—	—	21	69
Amortization of prior service credit	(57)	(48)	(411)	(411)
Amortization of actuarial (gain) loss	3,319	3,916	(541)	—
Net periodic pension cost	$ 8,174	$ 9,182	$ 3,314	$ 5,541

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 14,093	$ 15,153	$ 8,117	$ 11,687
Interest cost	21,284	20,095	9,318	10,789
Expected return on assets	(20,642)	(19,308)	(4,698)	(4,824)
Amortization of transition obligation	—	—	62	205
Amortization of prior service credit	(170)	(144)	(1,233)	(1,233)
Amortization of actuarial (gain) loss	9,959	11,749	(1,625)	—
Net periodic pension cost	$ 24,524	$ 27,545	$ 9,941	$ 16,624

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2016 and 2015 are as follows:

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Discount rate	4.55%	4.43%	4.55%	4.43%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.00%	7.25%	4.45%	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 plan as of January 1, 2016. Based on that determination, we are not required to make a minimum contribution to our defined benefit plan; however, we made a voluntary contribution of $15.0 million during the third quarter of fiscal 2016.

We contributed $12.8 million to our other post-retirement benefit plans during the nine months ended June 30, 2016 . We expect to contribute between $15 million and $25 million to these plans during fiscal 2016 .

8 . 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, 2015 , there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2016 .

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. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015 . There were no material changes to the purchase commitments for the nine months ended June 30, 2016 .

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015 . Except for purchases made in the normal course of business under these contracts, there were no material changes to the purchase commitments for the nine months ended June 30, 2016 .

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, 2015 . There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2016 .

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, 2016 , rate cases were in progress in our Kentucky and Virginia service areas, two formula rate mechanisms were in progress in our Louisiana service area and an infrastructure mechanism was in progress in our Mississippi service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments* .

9. 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, 2015 . During the nine months ended June 30, 2016 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 2015 - 2016 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 33 percent , or 23.0 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 54 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, 2016 , 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, 2016 , we had $18.4 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, 2016 , 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, 2016 , 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	—	(35,118)
	Cash Flow	—	45,325
	Not designated	10,002	51,128
		10,002	61,335

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, 2016 and September 30, 2015 . The gross amounts of recognized assets and liabilities are netted within our unaudited Condensed Consolidated Balance Sheets to the extent that we have netting arrangements with the counterparties.

		Regulated Distribution		Nonregulated	
	Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
		(In thousands)			
June 30, 2016					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 10,149	$ (35,680)
Interest rate contracts	Other current assets / Other current liabilities	—	(65,533)	—	—
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	3,911	(3,831)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(184,131)	—	—
Total		—	(249,664)	14,060	(39,511)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	3,651	(40)	27,247	(20,407)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	750	—	10,812	(9,983)
Total		4,401	(40)	38,059	(30,390)
Gross Financial Instruments		4,401	(249,704)	52,119	(69,901)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(51,210)	51,210
Net Financial Instruments		4,401	(249,704)	909	(18,691)
Cash collateral		—	16,330	4,046	18,691
Net Assets/Liabilities from Risk Management Activities		$ 4,401	$ (233,374)	$ 4,955	$ —

	Balance Sheet Location	Regulated Distribution Assets	Regulated Distribution Liabilities	Nonregulated Assets	Nonregulated Liabilities
		(In thousands)			
September 30, 2015					
Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	$ —	$ —	$ 11,680	$ (36,067)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	—	126	(9,918)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(110,539)	—	—
Total		—	(110,539)	11,806	(45,985)
Not Designated As Hedges:					
Commodity contracts	Other current assets / Other current liabilities	378	(9,568)	65,239	(65,780)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	368	—	14,318	(14,218)
Total		746	(9,568)	79,557	(79,998)
Gross Financial Instruments		746	(120,107)	91,363	(125,983)
Gross Amounts Offset on Consolidated Balance Sheet:					
Contract netting		—	—	(91,363)	91,363
Net Financial Instruments		746	(120,107)	—	(34,620)
Cash collateral		—	—	8,854	34,620
Net Assets/Liabilities from Risk Management Activities		$ 746	$ (120,107)	$ 8,854	$ —

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, 2016 and 2015 we recognized gains arising from fair value and cash flow hedge ineffectiveness of $13.6 million and $3.6 million . For the nine months ended June 30, 2016 and 2015 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $18.1 million and $(0.9) 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, 2016 and 2015 is presented below.

	Three Months Ended June 30 2016	Three Months Ended June 30 2015
	(In thousands)	
Commodity contracts	$ (22,146)	$ (1,715)
Fair value adjustment for natural gas inventory designated as the hedged item	35,630	5,350
Total decrease in purchased gas cost	$ 13,484	$ 3,635
The decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (684)	$ 599
Timing ineffectiveness	14,168	3,036
	$ 13,484	$ 3,635

	Nine Months Ended June 30	
	2016	2015
	(In thousands)	
Commodity contracts	$ (11,808)	$ 5,754
Fair value adjustment for natural gas inventory designated as the hedged item	29,852	(6,291)
Total (increase) decrease in purchased gas cost	$ 18,044	$ (537)
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (1,490)	$ 908
Timing ineffectiveness	19,534	(1,445)
	$ 18,044	$ (537)

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, 2016 and 2015 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, 2016		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (12,347)	$ (12,347)
Gain arising from ineffective portion of commodity contracts	—	66	66
Total impact on purchased gas cost	—	(12,281)	(12,281)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(137)	—	(137)
Total Impact from Cash Flow Hedges	$ (137)	$ (12,281)	$ (12,418)

	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)

	Nine Months Ended June 30, 2016		
	Regulated Distribution	Nonregulated	Consolidated
		(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ —	$ (48,015)	$ (48,015)
Gain arising from ineffective portion of commodity contracts	—	84	84
Total impact on purchased gas cost	—	(47,931)	(47,931)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(410)	—	(410)
Total Impact from Cash Flow Hedges	$ (410)	$ (47,931)	$ (48,341)

	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)

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, 2016 and 2015 . 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	
	2016	2015	2016	2015
		(In thousands)		
Increase (decrease) in fair value:				
Interest rate agreements	$ (39,337)	$ 54,388	$ (88,345)	$ (30,436)
Forward commodity contracts	10,573	1,505	(8,612)	(37,397)
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	87	87	260	455
Forward commodity contracts	7,532	10,058	29,290	17,826
Total other comprehensive income (loss) from hedging, net of tax [1]	$ (21,145)	$ 66,038	$ (67,407)	$ (49,552)

(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 losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2016 . 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	$ (372)	$ (4,992)	$ (5,364)
Thereafter	(18,018)	233	(17,785)
Total [(1)]	$ (18,390)	$ (4,759)	$ (23,149)

(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, 2016 and 2015 was a decrease in purchased gas cost of $1.9 million and $3.7 million . For the nine months ended June 30, 2016 and 2015 purchased gas cost (increased) decreased by $(2.8) million and $13.2 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.

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, 2015 . During the nine months ended June 30, 2016 , 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, 2015 .

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, 2016 and September 30, 2015 . 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, 2016
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 4,401	$ —	$ —	$ 4,401
Nonregulated segment	—	52,119	—	(47,164)	4,955
Total financial instruments	—	56,520	—	(47,164)	9,356
Hedged portion of gas stored underground	97,860	—	—	—	97,860
Available-for-sale securities					
Money market funds	—	1,358	—	—	1,358
Registered investment companies	39,068	—	—	—	39,068
Bonds	—	31,319	—	—	31,319
Total available-for-sale securities	39,068	32,677	—	—	71,745
Total assets	$ 136,928	$ 89,197	$ —	$ (47,164)	$ 178,961
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 249,704	$ —	$ (16,330)	$ 233,374
Nonregulated segment	—	69,901	—	(69,901)	—
Total liabilities	$ —	$ 319,605	$ —	$ (86,231)	$ 233,374

	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, 2015
			(In thousands)		
Assets:					
Financial instruments					
Regulated distribution segment	$ —	$ 746	$ —	$ —	$ 746
Nonregulated segment	—	91,363	—	(82,509)	8,854
Total financial instruments	—	92,109	—	(82,509)	9,600
Hedged portion of gas stored underground	43,901	—	—	—	43,901
Available-for-sale securities					
Money market funds	—	1,072	—	—	1,072
Registered investment companies	40,619	—	—	—	40,619
Bonds	—	32,509	—	—	32,509
Total available-for-sale securities	40,619	33,581	—	—	74,200
Total assets	$ 84,520	$ 125,690	$ —	$ (82,509)	$ 127,701
Liabilities:					
Financial instruments					
Regulated distribution segment	$ —	$ 120,107	$ —	$ —	$ 120,107
Nonregulated segment	—	125,983	—	(125,983)	—
Total liabilities	$ —	$ 246,090	$ —	$ (125,983)	$ 120,107

(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, 2016 , we had $16.3 million of cash held in margin accounts to collateralize certain regulated distribution financial instruments, which were used to offset current and noncurrent risk management liabilities. As of June 30, 2016 , we also had $22.7 million of cash held in margin accounts to collateralize certain nonregulated financial instruments. Of this amount, $18.7 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $4.0 million 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, 2015 , we had $43.5 million of cash held in margin accounts to collateralize certain nonregulated financial instruments. Of this amount, $34.6 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $8.9 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, 2016				
Domestic equity mutual funds	$ 28,377	$ 5,549	$ (962)	$ 32,964
Foreign equity mutual funds	5,357	747	—	6,104
Bonds	31,147	175	(3)	31,319
Money market funds	1,358	—	—	1,358
	$ 66,239	$ 6,471	$ (965)	$ 71,745
As of September 30, 2015				
Domestic equity mutual funds	$ 27,643	$ 7,332	$ (456)	$ 34,519
Foreign equity mutual funds	5,261	905	(66)	6,100
Bonds	32,423	106	(20)	32,509
Money market funds	1,072	—	—	1,072
	$ 66,399	$ 8,343	$ (542)	$ 74,200

At June 30, 2016 and September 30, 2015 , our available-for-sale securities included $40.4 million and $41.7 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At June 30, 2016 , we maintained investments in bonds that have contractual maturity dates ranging from July 2016 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, 2016 and September 30, 2015 :

	June 30, 2016	September 30, 2015
	(In thousands)	
Carrying Amount	$ 2,460,000	$ 2,460,000
Fair Value	$ 2,858,540	$ 2,669,323

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, 2015 . During the nine months ended June 30, 2016 , 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, 2016 and the related condensed consolidated statements of income and comprehensive income for the three and nine -month periods ended June 30, 2016 and 2015 and the condensed consolidated statements of cash flows for the nine -month periods ended June 30, 2016 and 2015 . 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, 2015 , and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for the year then ended, not presented herein, and we expressed an unqualified audit opinion on those consolidated financial statements in our report dated November 6, 2015. In our opinion, the accompanying condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2015, is fairly stated, in all material respects, in relation to the consolidated balance sheets from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
August 3, 2016

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, 2015 .

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit and capital 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 commodity price volatility, counterparty creditworthiness or performance and interest rate risk; 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 regulated distribution business; increased costs of providing health care benefits along with pension and postretirement health care benefits and increased funding requirements; the inability to continue to hire, train and retain appropriate personnel; 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 climate changes or related additional legislation or regulation in the future; the inherent hazards and risks involved in operating our distribution and pipeline and storage businesses; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission 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, 2016 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 transmission 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, 2015 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, 2016 .

RESULTS OF OPERATIONS

Executive Summary

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

During the first nine months of fiscal 2016 , we earned $315.9 million , or $3.06 per diluted share, an eight percent increase period over period. Regulated operations generated 88 and 95 percent of our consolidated net income for the three and nine months ended June 30, 2016 . 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		
	2016	**2015**	**Change**
	(In thousands, except per share data)		
Regulated operations	$ 62,986	$ 51,032	$ 11,954
Nonregulated operations	8,207	5,249	2,958
Net income	$ 71,193	$ 56,281	$ 14,912
Diluted EPS from regulated operations	$ 0.61	$ 0.50	$ 0.11
Diluted EPS from nonregulated operations	0.08	0.05	0.03
Consolidated diluted EPS	$ 0.69	$ 0.55	$ 0.14

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, except per share data)		
Regulated operations	$ 301,324	$ 273,989	$ 27,335
Nonregulated operations	14,540	17,571	(3,031)
Net income	$ 315,864	$ 291,560	$ 24,304
Diluted EPS from regulated operations	$ 2.92	$ 2.69	$ 0.23
Diluted EPS from nonregulated operations	0.14	0.17	(0.03)
Consolidated diluted EPS	$ 3.06	$ 2.86	$ 0.20

Positive rate outcomes achieved in our regulated businesses offset the effect of weather that was 25 percent warmer than the prior-year period. As of June 30, 2016 , we had completed 16 regulatory proceedings resulting in an increase in annual operating income of $104.4 million and had five ratemaking efforts in progress seeking $24.5 million of additional annual operating income. Our nonregulated results in the current-year period reflect larger losses on the settlement of financial positions during a period of falling gas prices.

Capital expenditures for the first nine months of fiscal 2016 were $796.0 million . Approximately 83 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 $1 billion and $1.1 billion for fiscal 2016 . We funded our capital expenditure program primarily through operating cash flows of $624.6 million , net short-term borrowings and the issuance of common stock. On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. During the third fiscal quarter of 2016, we issued 1.4 million shares of common stock and received $98.7 million in net proceeds under the ATM program.

On May 13, 2016, Standard & Poor's Corporation upgraded our senior unsecured debt rating to A from A- and upgraded our short-term debt rating to A-1 from A-2, with a ratings outlook of stable, citing strong financial performance largely due to our ability to timely recover capital investments.

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 7.7 percent for fiscal 2016.

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 includes 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, 2016 compared with Three Months Ended June 30, 2015

Financial and operational highlights for our regulated distribution segment for the three months ended June 30, 2016 and 2015 are presented below.

	Three Months Ended June 30		
	2016	**2015**	**Change**
	(In thousands, unless otherwise noted)		
Gross profit	$ 275,381	$ 267,019	$ 8,362
Operating expenses	212,152	210,219	1,933
Operating income	63,229	56,800	6,429
Miscellaneous income	1,111	1,045	66
Interest charges	18,968	19,961	(993)
Income before income taxes	45,372	37,884	7,488
Income tax expense	15,516	15,420	96
Net income	$ 29,856	$ 22,464	$ 7,392
Consolidated regulated distribution sales volumes — MMcf	34,983	36,126	(1,143)
Consolidated regulated distribution transportation volumes — MMcf	30,416	30,134	282
Total consolidated regulated distribution throughput — MMcf	65,399	66,260	(861)
Consolidated regulated distribution average cost of gas per Mcf sold	$ 3.97	$ 4.15	$ (0.18)

Income for our regulated distribution segment increased 33 percent, primarily due to an $8.4 million increase in gross profit, partially offset with a $1.9 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $6.5 million net increase in rate adjustments, primarily in our Mississippi, Louisiana, West Texas and Kentucky/Mid-States Divisions.
- Customer growth, primarily in our Mid-Tex, Louisiana and Tennessee service areas, which contributed an incremental $1.5 million.

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 higher levels of system maintenance and higher depreciation expense associated with increased capital investments.

Net income for the three months ended June 30, 2016 includes a $1.6 million income tax benefit for equity awards that vested during the current-year quarter as a result of adopting the new stock-based accounting guidance.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the three months ended June 30, 2016 and 2015 . 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		
	2016	2015	Change
	(In thousands)		
Mid-Tex	$ 33,818	$ 33,473	$ 345
Kentucky/Mid-States	6,955	10,104	(3,149)
Louisiana	9,288	6,561	2,727
West Texas	5,709	5,018	691
Mississippi	3,959	1,546	2,413
Colorado-Kansas	3,152	1,872	1,280
Other	348	(1,774)	2,122
Total	$ 63,229	$ 56,800	$ 6,429

Nine Months Ended June 30, 2016 compared with Nine Months Ended June 30, 2015

Financial and operational highlights for our regulated distribution segment for the nine months ended June 30, 2016 and 2015 are presented below.

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 1,017,984	$ 997,066	$ 20,918
Operating expenses	617,625	617,451	174
Operating income	400,359	379,615	20,744
Miscellaneous income (expense)	209	(1,221)	1,430
Interest charges	58,390	60,914	(2,524)
Income before income taxes	342,178	317,480	24,698
Income tax expense	124,755	121,776	2,979
Net income	$ 217,423	$ 195,704	$ 21,719
Consolidated regulated distribution sales volumes — MMcf	215,632	265,503	(49,871)
Consolidated regulated distribution transportation volumes — MMcf	103,304	107,205	(3,901)
Total consolidated regulated distribution throughput — MMcf	318,936	372,708	(53,772)
Consolidated regulated distribution average cost of gas per Mcf sold	$ 4.10	$ 5.26	$ (1.16)

Income for our regulated distribution segment increased 11 percent, primarily due to a $20.9 million increase in gross profit. The year-over-year increase in gross profit primarily reflects:

- a $37.2 million net increase in rate adjustments. Our Mid-Tex Division accounted for $16.3 million of this increase. We also experienced increases in our Mississippi and West Texas Divisions.
- The impact of weather that was 25 percent warmer than the prior-year period, before adjusting for weather normalization mechanisms. Therefore, although sales volumes declined 19 percent, gross margin experienced just a $3.6 million decline from lower consumption. Warmer weather also contributed to a $2.5 million decrease in service and other revenues.
- Customer growth, primarily in our Mid-Tex, Louisiana and Tennessee service areas, which contributed an incremental $4.9 million.
- a $14.5 million decrease in revenue-related taxes primarily in our Mid-Tex and West Texas Divisions, offset by a corresponding $15.4 million decrease in the related tax expense.

Net income for the nine months ended June 30, 2016 includes a $4.9 million income tax benefit for equity awards that vested during the current-year period as a result of adopting the new stock-based accounting guidance.

The following table shows our operating income by regulated distribution division, in order of total rate base, for the nine months ended June 30, 2016 and 2015 . 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		
	2016	2015	Change
		(In thousands)	
Mid-Tex	$ 182,594	$ 166,586	$ 16,008
Kentucky/Mid-States	56,334	59,256	(2,922)
Louisiana	48,082	47,380	702
West Texas	38,937	33,820	5,117
Mississippi	40,491	37,356	3,135
Colorado-Kansas	31,308	29,129	2,179
Other	2,613	6,088	(3,475)
Total	$ 400,359	$ 379,615	$ 20,744

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 2016 , we completed 15 regulatory proceedings, resulting in a $63.7 million increase in annual operating income as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Annual formula rate mechanisms	$ 59,414
Rate case filings	4,456
Other rate activity	(183)
	$ 63,687

Additionally, the following ratemaking efforts seeking $24.5 million in annual operating income were in progress as of June 30, 2016 :

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	Rate Case (1)	Kentucky	$ 5,531
Kentucky/Mid-States	Expedited Rate Filing (2)	Virginia	537
Louisiana	Formula Rate Mechanism (2)	Trans LA	6,216
Louisiana	Formula Rate Mechanism (2)	LGS	8,686
Mississippi	Infrastructure Mechanism	Mississippi	3,519
			$ 24,489

(1) The parties filed a unanimous settlement that, if accepted by the Kentucky Pubic Service Commission, will result in an increase to operating revenue of $2.7 million on August 15, 2016.

(2) The proposed increase for Virginia and Louisiana customers was implemented on April 1, 2016 (Trans LA & Virginia) and July 1, 2016 (LGS), subject to refund.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have formula rate mechanisms in our Louisiana, Mississippi and Tennessee operations and in substantially all of our Texas divisions. Additionally, we have specific infrastructure programs in substantially all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	**Infrastructure Programs**	**Formula Rate Mechanisms**
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes, until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following annual formula rate mechanisms were approved during the nine months ended June 30, 2016 .

Division	**Jurisdiction**	**Test Year Ended**	**Increase in Annual Operating Income**	**Effective Date**
			(In thousands)	
2016 Filings:				
Kentucky/Mid-States	Tennessee	05/31/2017	$ 4,888	06/01/2016
Mid-Tex	Mid-Tex Cities RRM	12/31/2015	25,816	06/01/2016
Mid-Tex	Mid-Tex DARR	09/30/2015	5,429	06/01/2016
Mid-Tex	Mid-Tex Environs	12/31/2015	1,325	05/03/2016
West Texas	West Texas Environs	12/31/2015	646	05/03/2016
West Texas	West Texas ALDC	12/31/2015	3,484	04/26/2016
Colorado-Kansas	Colorado	12/31/2016	764	01/01/2016
Mississippi	Mississippi-SRF (1)	10/31/2016	9,192	01/01/2016
Mississippi	Mississippi-SGR (2)	10/31/2016	250	12/01/2015
Kentucky/Mid-States	Kentucky-PRP	09/30/2016	3,786	10/01/2015
Kentucky/Mid-States	Virginia-SAVE	09/30/2016	118	10/01/2015
West Texas	West Texas Cities	09/30/2015	3,716	10/01/2015
Total 2016 Filings			$ 59,414	

(1) The commission issued a final order approving a $9.2 million increase in annual operating income on December 21, 2015 with an effective date of January 1, 2016.

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

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 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, 2016 .

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2016 Rate Case Filings:			
Colorado-Kansas	Kansas	$ 2,372	03/17/2016
Colorado-Kansas	Colorado	2,084	01/01/2016
Total 2016 Rate Case Filings		$ 4,456	

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2016 .

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2016 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem (1)	$ (183)	02/01/2016
Total 2016 Other Rate Activity			$ (183)	

(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 and stores natural gas for our Mid-Tex Division and third party local distribution companies and manages five underground storage facilities in Texas. We also provide interruptible transportation, storage and ancillary services to electric generation and industrial customers as well as producers, marketers and other shippers.

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 and storage 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 the volumes of gas transported for shippers through our pipeline system and the rates for such transportation.

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 transporter 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. Additionally, the Atmos Pipeline–Texas Division annually uses GRIP to recover capital costs incurred in the prior calendar year.

Three Months Ended June 30, 2016 compared with Three Months Ended June 30, 2015

Financial and operational highlights for our regulated pipeline segment for the three months ended June 30, 2016 and 2015 are presented below.

	Three Months Ended June 30		
	2016	**2015**	**Change**
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 83,503	$ 71,989	$ 11,514
Third-party transportation	22,715	22,724	(9)
Storage and park and lend services	931	664	267
Other	2,100	1,631	469
Gross profit	109,249	97,008	12,241
Operating expenses	48,712	44,581	4,131
Operating income	60,537	52,427	8,110
Miscellaneous expense	(359)	(211)	(148)
Interest charges	9,002	8,299	703
Income before income taxes	51,176	43,917	7,259
Income tax expense	18,046	15,349	2,697
Net income	$ 33,130	$ 28,568	$ 4,562
Gross pipeline transportation volumes — MMcf	156,489	165,898	(9,409)
Consolidated pipeline transportation volumes — MMcf	128,801	134,823	(6,022)

Net income for our regulated pipeline segment increased 16 percent, primarily due to a $12.2 million increase in gross profit, offset by a $4.1 million increase in operating expenses. The increase in gross profit primarily reflects an $11.3 million increase in rates from the GRIP filings approved in fiscal 2015 and 2016.

Operating expenses increased $4.1 million , primarily due to increased levels of pipeline maintenance activities and higher depreciation expense associated with increased capital investments.

On May 3, 2016, a GRIP filing was approved by the Railroad Commission of Texas for $40.7 million of additional annual operating income, effective with bills rendered on and after May 3, 2016.

Nine Months Ended June 30, 2016 compared with Nine Months Ended June 30, 2015

Financial and operational highlights for our regulated pipeline segment for the nine months ended June 30, 2016 and 2015 are presented below.

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$ 224,662	$ 192,734	$ 31,928
Third-party transportation	63,597	71,203	(7,606)
Storage and park and lend services	2,495	2,737	(242)
Other	8,875	5,631	3,244
Gross profit	299,629	272,305	27,324
Operating expenses	141,189	125,270	15,919
Operating income	158,440	147,035	11,405
Miscellaneous expense	(1,164)	(842)	(322)
Interest charges	27,294	25,014	2,280
Income before income taxes	129,982	121,179	8,803
Income tax expense	46,081	42,894	3,187
Net income	$ 83,901	$ 78,285	$ 5,616
Gross pipeline transportation volumes — MMcf	520,233	567,906	(47,673)
Consolidated pipeline transportation volumes — MMcf	373,000	381,828	(8,828)

Net income for our regulated pipeline segment increased seven percent, primarily due to a $27.3 million increase in gross profit, partially offset by a $15.9 million increase in operating expenses. The increase in gross profit primarily reflects a $28.4 million increase in rates from the GRIP filings approved in fiscal 2015 and 2016 and a $3.6 million increase from the sale of excess retention gas. These increases were partially offset by a $4.0 million decrease in through-system volumes and lower storage and blending fees due to warmer weather in the current-year period compared to the prior-year period.

Operating expenses increased $15.9 million , primarily due to increased levels of pipeline maintenance activities to improve the safety and reliability of our system and increased property taxes and depreciation expense associated with increased capital investments.

Nonregulated Segment

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

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

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

Our nonregulated activities are significantly influenced by competitive factors in the industry and general economic conditions. Therefore, the margins earned from these activities are dependent upon our ability to attract and retain customers and to minimize the cost of buying, selling and delivering natural gas to offer more competitive pricing to those customers.

Natural gas prices can influence:

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

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

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Increased or decreased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

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

Three Months Ended June 30, 2016 compared with Three Months Ended June 30, 2015

Financial and operating highlights for our nonregulated segment for the three months ended June 30, 2016 and 2015 are presented below.

	Three Months Ended June 30		
	2016	**2015**	**Change**
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 8,899	$ 10,648	$ (1,749)
Storage and transportation services	3,616	3,607	9
Other	6,047	1,508	4,539
Total realized margins	18,562	15,763	2,799
Unrealized margins	4,252	2,016	2,236
Gross profit	22,814	17,779	5,035
Operating expenses	9,416	9,399	17
Operating income	13,398	8,380	5,018
Miscellaneous income	574	345	229
Interest charges	221	240	(19)
Income before income taxes	13,751	8,485	5,266
Income tax expense	5,544	3,236	2,308
Net income	$ 8,207	$ 5,249	$ 2,958
Gross nonregulated delivered gas sales volumes — MMcf	88,472	89,052	(580)
Consolidated nonregulated delivered gas sales volumes — MMcf	76,798	75,929	869
Net physical position (Bcf)	30.6	22.1	8.5

The $5.0 million quarter-over-quarter increase in gross profit reflects a $2.8 million increase in realized margins, combined with a $2.2 million increase in unrealized margins. The following were the key drivers for the $2.8 million increase in realized margins:

- Other realized margins increased $4.5 million . The increase primarily reflects larger settlement gains on short financial positions established during the first and second quarter of fiscal 2016.
- Margins from gas delivery and related services margins decreased $1.7 million , primarily due to a decrease in per-unit margins from 12 cents to 10 cents per Mcf, primarily due to increased demand from low-margin power generation and marketing customers due to warmer weather.

Unrealized margins increased $2.2 million , primarily due to the period-over-period favorable movement of the physical mark on the fair value of natural gas inventory hedged positions.

Nine Months Ended June 30, 2016 compared with Nine Months Ended June 30, 2015

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$ 37,454	$ 39,280	$ (1,826)
Storage and transportation services	10,143	10,273	(130)
Other	(8,718)	(1,322)	(7,396)
Total realized margins	38,879	48,231	(9,352)
Unrealized margins	12,792	8,493	4,299
Gross profit	51,671	56,724	(5,053)
Operating expenses	27,085	27,832	(747)
Operating income	24,586	28,892	(4,306)
Miscellaneous income	1,245	897	348
Interest charges	1,408	706	702
Income before income taxes	24,423	29,083	(4,660)
Income tax expense	9,883	11,512	(1,629)
Net income	$ 14,540	$ 17,571	$ (3,031)
Gross nonregulated delivered gas sales volumes — MMcf	292,619	319,423	(26,804)
Consolidated nonregulated delivered gas sales volumes — MMcf	257,733	272,260	(14,527)
Net physical position (Bcf)	30.6	22.1	8.5

The $5.1 million year-over-year decrease in gross profit reflects a $9.4 million decrease in realized margins, partially offset by a $4.3 million increase in unrealized margins. The following were the key drivers for the $9.4 million decrease in realized margins:

- Margins from gas delivery and related services decreased $1.8 million year-over-year. Consolidated sales volumes decreased five percent due to warmer weather. However, lower net transportation costs and other variable costs driven by fewer deliveries resulted in an increase in per-unit margins from 12 cents to 13 cents per Mcf, which partially offset the effect of reduced sales volumes.
- Other realized margins decreased $7.4 million . The decrease primarily reflects higher realized losses incurred during the first six months of fiscal 2016 on the settlement of long financial positions during a period of falling prices. Additionally, storage fees rose primarily due to increased park and loan activity. The aforementioned settlement gains realized during the third quarter partially offset these period over period decreases.

Unrealized margins increased $4.3 million , primarily due to the period-over-period favorable movement of the physical mark on the fair value of natural gas inventory hedged positions.

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 45 to 55 percent. We also evaluate the levels of committed borrowing capacity that we require. We currently have over $1 billion of capacity under 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 filed a registration statement with the SEC on March 28, 2016 to issue, from time to time, up to $2.5 billion in common stock and/or debt securities, which replaced our registration statement that expired on March 28, 2016. On March 28, 2016, we entered into an at-the-market (ATM) equity distribution agreement under which we may issue and sell, shares of our common stock, up to an aggregate offering price of

$200 million. The shares will be issued under our shelf registration statement. Proceeds from the ATM program will be used primarily to repay short-term debt outstanding under our $1.25 billion commercial paper program, to fund capital spending primarily to enhance the safety and reliability of our system and for general corporate purposes. During the third fiscal quarter of 2016, we issued 1.4 million shares of common stock and received $98.7 million in net proceeds under the ATM program. At June 30, 2016 , $2.4 billion of securities remain available for issuance under the shelf registration statement.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2016 , September 30, 2015 and June 30, 2015 :

	June 30, 2016		September 30, 2015		June 30, 2015	
	(In thousands, except percentages)					
Short-term debt	$ 670,466	10.2%	$ 457,927	7.5%	$ 251,977	4.2%
Long-term debt [(1)]	2,455,645	37.2%	2,455,388	40.2%	2,455,303	41.3%
Shareholders' equity	3,466,724	52.6%	3,194,797	52.3%	3,238,255	54.5%
Total	$ 6,592,835	100.0%	$ 6,108,112	100.0%	$ 5,945,535	100.0%

[(1)] In June 2017, $250 million of long-term debt will mature. We plan to issue new senior notes to replace this maturing debt. We have executed forward starting interest rate swaps to effectively fix the Treasury yield component associated with this anticipated issuance at 3.37%.

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, 2016 and 2015 are presented below.

	Nine Months Ended June 30		
	2016	2015	Change
	(In thousands)		
Total cash provided by (used in)			
Operating activities	$ 624,598	$ 717,582	$ (92,984)
Investing activities	(794,381)	(668,602)	(125,779)
Financing activities	207,336	(48,085)	255,421
Change in cash and cash equivalents	37,553	895	36,658
Cash and cash equivalents at beginning of period	28,653	42,258	(13,605)
Cash and cash equivalents at end of period	$ 66,206	$ 43,153	$ 23,053

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, 2016 , we generated cash flow of $624.6 million from operating activities compared with $717.6 million for the nine months ended June 30, 2015 . The $93.0 million decrease in operating cash flows primarily reflects the timing of deferred gas cost recoveries.

Cash flows from investing activities

In executing our regulatory strategy, we target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions 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 our ongoing construction program, which 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. Over the last three fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system. We anticipate our annual capital spending will be in the range of $1 billion to $1.4 billion through fiscal 2020.

For the nine months ended June 30, 2016 , capital expenditures were $796.0 million , compared with $667.5 million in the prior-year period. The $128.5 million increase primarily reflects an 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 combined with a planned increase in spending in our regulated distribution operations.

Cash flows from financing activities

For the nine months ended June 30, 2016 , our financing activities generated $207.3 million of cash compared with $48.1 million of cash used in the prior-year period. The $255.4 million increase of cash generated is primarily due to higher net short-term debt borrowings due to increased capital expenditures and period-over-period changes in working capital funding needs compared to the prior year, as well as proceeds received from the issuance of common stock under our ATM program in the third fiscal quarter of 2016.

The following table summarizes our share issuances for the nine months ended June 30, 2016 and 2015 .

	Nine Months Ended June 30	
	2016	2015
Shares issued:		
Direct Stock Purchase Plan	107,736	137,049
1998 Long-Term Incentive Plan	597,470	664,074
Retirement Savings Plan and Trust	282,578	296,067
At-the-Market (ATM) Equity Sales Program	1,360,756	—
Total shares issued	2,348,540	1,097,190

The year-over-year increase in the number of shares issued primarily reflects shares issued under the ATM Program. For the nine months ended June 30, 2016, we did not cancel and retire any shares attributable to federal income tax withholdings on equity awards. For the nine months ended June 30, 2015, we canceled and retired 148,464 such shares.

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, 2016 , the amount available to us under our credit facilities, net of commercial paper and outstanding letters of credit, was $0.6 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). On May 13, 2016, S&P upgraded our senior unsecured debt rating to A from A- and upgraded our short-term debt rating to A-1 from A-2, with a ratings outlook of stable, citing strong financial performance largely due to our ability to timely recover capital investments. As of June 30, 2016 , all three rating agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

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

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of June 30, 2016 . 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 8 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, 2016 .

Risk Management Activities

We conduct risk management activities through our regulated distribution and nonregulated segments. In our regulated distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. Additionally, we manage interest rate risk by entering into financial instruments to effectively fix the Treasury yield component of the interest cost associated with anticipated financings.

In our nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

The following table shows the components of the change in fair value of our regulated distribution segment's financial instruments for the three and nine months ended June 30, 2016 and 2015 :

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(In thousands)			
Fair value of contracts at beginning of period	$ (187,864)	$ (137,710)	$ (119,361)	$ 14,284
Contracts realized/settled	(107)	(48)	(20,865)	(33,859)
Fair value of new contracts	2,377	1,514	2,434	1,365
Other changes in value	(59,709)	85,993	(107,511)	(32,041)
Fair value of contracts at end of period	(245,303)	(50,251)	(245,303)	(50,251)
Netting of cash collateral	16,330	—	16,330	—
Cash collateral and fair value of contracts at period end	$ (228,973)	$ (50,251)	$ (228,973)	$ (50,251)

The fair value of our regulated distribution segment's financial instruments at June 30, 2016 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2016				
	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	$ (61,922)	$ (183,381)	$ —	$ —	$ (245,303)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (61,922)	$ (183,381)	$ —	$ —	$ (245,303)

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the three and nine months ended June 30, 2016 and 2015 :

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(In thousands)			
Fair value of contracts at beginning of period	$ (16,085)	$ (36,140)	$ (34,620)	$ (3,033)
Contracts realized/settled	1,303	11,502	22,050	23,013
Fair value of new contracts	—	—	—	—
Other changes in value	(3,000)	4,121	(5,212)	(40,497)
Fair value of contracts at end of period	(17,782)	(20,517)	(17,782)	(20,517)
Netting of cash collateral	22,737	31,323	22,737	31,323
Cash collateral and fair value of contracts at period end	$ 4,955	$ 10,806	$ 4,955	$ 10,806

The fair value of our nonregulated segment's financial instruments at June 30, 2016 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2016				
	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	$ (18,691)	$ 621	$ 288	$ —	$ (17,782)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (18,691)	$ 621	$ 288	$ —	$ (17,782)

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2016 and 2015 , our total net periodic pension and other benefits costs were $34.5 million and $44.2 million . A substantial portion of those costs relating to our regulated distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2016 net periodic pension cost is approximately 20 percent lower than in fiscal 2015. The decrease is attributable to the net impact of changes in the various assumptions used to establish those costs as of September 30, 2015, our most recent measurement date. The most significant changes include:

- An increase in the discount rate from 4.43 percent to 4.55 percent
- A decrease in the expected return on plan assets from 7.25 percent to 7.00 percent
- Utilization of updated mortality tables issued in October 2015 by the Society of Actuaries

The amount with which we fund our defined benefit plan is determined in accordance with the Pension Protection Act of 2006 (PPA) and are influenced by the funded position of the plan when the funding requirements are determined on January 1 of each year. Based upon the determination as of January 1, 2015, we are not required to make a minimum contribution to our defined benefit plan during fiscal 2016. However, we made a voluntary contribution of $15.0 million during the third quarter of fiscal 2016.

For the nine months ended June 30, 2016 we contributed $12.8 million to our postretirement medical plans. We anticipate contributing between $15 million and $25 million to our postretirement plans during fiscal 2016 .

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

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our regulated distribution, regulated pipeline and nonregulated segments for the three and nine month periods ended June 30, 2016 and 2015 .

Regulated Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
METERS IN SERVICE, end of period				
Residential	2,903,099	2,872,584	2,903,099	2,872,584
Commercial	266,435	262,353	266,435	262,353
Industrial	1,463	1,518	1,463	1,518
Public authority and other	8,377	8,419	8,377	8,419
Total meters	3,179,374	3,144,874	3,179,374	3,144,874
INVENTORY STORAGE BALANCE — Bcf	51.3	42.6	51.3	42.6
SALES VOLUMES — MMcf [(1)]				
Gas sales volumes				
Residential	16,407	16,667	125,334	159,067
Commercial	14,718	15,216	73,990	87,852
Industrial	2,671	2,925	10,586	11,713
Public authority and other	1,187	1,318	5,722	6,871
Total gas sales volumes	34,983	36,126	215,632	265,503
Transportation volumes	33,367	33,743	112,477	117,019
Total throughput	68,350	69,869	328,109	382,522
OPERATING REVENUES (000's) [(1)]				
Gas sales revenues				
Residential	$ 260,634	$ 253,033	$ 1,240,184	$ 1,538,771
Commercial	113,075	114,942	507,580	666,220
Industrial	9,456	13,089	41,309	62,694
Public authority and other	7,309	8,465	34,402	46,355
Total gas sales revenues	390,474	389,529	1,823,475	2,314,040
Transportation revenues	18,097	16,506	60,202	57,635
Other gas revenues	5,655	10,759	18,836	22,504
Total operating revenues	$ 414,226	$ 416,794	$ 1,902,513	$ 2,394,179
Average cost of gas per Mcf sold	$ 3.97	$ 4.15	$ 4.10	$ 5.26

See footnote following these tables.

Regulated Pipeline and Nonregulated Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
CUSTOMERS, end of period				
Industrial	767	750	767	750
Municipal	133	129	133	129
Other	518	516	518	516
Total	1,418	1,395	1,418	1,395
NONREGULATED INVENTORY STORAGE BALANCE — Bcf	40.9	28.2	40.9	28.2
REGULATED PIPELINE VOLUMES — MMcf (1)	156,489	165,898	520,233	567,906
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf (1)	88,472	89,052	292,619	319,423
OPERATING REVENUES (000's) (1)				
Regulated pipeline	$ 109,249	$ 97,008	$ 299,629	$ 272,305
Nonregulated	214,555	278,769	774,474	1,179,379
Total operating revenues	$ 323,804	$ 375,777	$ 1,074,103	$ 1,451,684

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, 2015 . During the nine months ended June 30, 2016 , 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, 2016 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, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1 . ***Legal Proceedings***

During the nine months ended June 30, 2016 , 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, 2015 . 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 3, 2016

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
10	Equity Distribution Agreement, dated as of March 28, 2016, among Atmos Energy Corporation, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC.	Exhibit 1.1 to Form 8-K dated March 28, 2016 (File No. 1-10042)
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.

Exhibit 12

Atmos Energy Corporation
Computation of Earnings to Fixed Charges

	Three Months Ended June 30		Nine Months Ended June 30	
	2016	2015	2016	2015
	(Dollars in thousands)			
Income from continuing operations before provision for income taxes per statement of income	$ 110,299	$ 90,286	$ 496,583	$ 467,742
Add:				
Portion of rents representative of the interest factor	3,193	3,041	9,469	9,320
Interest on debt & amortization of debt expense	27,698	27,955	85,741	85,166
Income as adjusted	$ 141,190	$ 121,282	$ 591,793	$ 562,228
Fixed charges:				
Interest on debt & amortization of debt expense (1)	$ 27,698	$ 27,955	$ 85,741	$ 85,166
Capitalized interest (2)	760	493	2,129	1,525
Rents	9,581	9,122	28,408	27,960
Portion of rents representative of the interest factor (3)	3,193	3,041	9,469	9,320
Fixed charges (1)+(2)+(3)	$ 31,651	$ 31,489	$ 97,339	$ 96,011
Ratio of earnings to fixed charges	4.46	3.85	6.08	5.86

Exhibit 15

Board of Directors
Atmos Energy Corporation

We are aware of the incorporation by reference in the Registration Statements (Form S-3, No. 33-37869; Form S-3, No. 33-58220; Form S-3D/A, No. 33-70212; Form S-3, No. 33-56915; Form S-3/A, No. 333-03339; Form S-3/A, No. 333-32475; Form S-3/A, No. 333-50477; Form S-3, No. 333-95525; Form S-3/A, No. 333-93705; Form S-3, No. 333-75576; Form S-3D, No. 333-113603; Form S-3, No. 333-118706; Form S-3D, No. 333-155666; Form S-3D, No. 333-208317; Form S-3ASR, No. 333-210424; Form S-4, No. 333-13429; Form S-8, No. 33-57687; Form S-8, No. 33-57695; Form S-8, No. 333-32343; Form S-8, No. 333-46337; Form S-8, No. 333-73143; Form S-8, No. 333-73145; Form S-8, No. 333-63738; Form S-8, No. 333-88832; Form S-8, No. 333-116367; Form S-8, No. 333-138209; Form S-8, No. 333-145817; Form S-8, No. 333-155570; Form S-8, No. 333-166639; Form S-8, No. 333-177593; Form S-8, No. 333-199301; and Form S-8, No. 333-210461) of Atmos Energy Corporation and in the related Prospectuses of our report dated August 3, 2016 , relating to the unaudited condensed consolidated interim financial statements of Atmos Energy Corporation, which are included in its Form 10-Q for the quarter ended June 30, 2016 .

/s/ ERNST & YOUNG LLP

Dallas, Texas
August 3, 2016

EXHIBIT 31

RULE 13a-14(a)/15d-14(a) CERTIFICATIONS

I, Kim R. Cocklin, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Atmos Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2016

/s/ KIM R. COCKLIN

Kim R. Cocklin
Chief Executive Officer

I, Bret J. Eckert, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Atmos Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing equivalent functions):
   (a) All significant deficiencies or material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2016

/s/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and
Chief Financial Officer

Exhibit 32

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)**

In connection with the Quarterly Report of Atmos Energy Corporation (the "Company") on Form 10-Q for the third quarter of the fiscal year ended September 30, 2016 , as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kim R. Cocklin, Chief Executive Officer of the Company, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

August 3, 2016

/s/ KIM R. COCKLIN

Kim R. Cocklin
Chief Executive Officer

A signed original of this written statement has been provided to Atmos Energy Corporation and will be retained by Atmos Energy Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

In connection with the Quarterly Report of Atmos Energy Corporation (the "Company") on Form 10-Q for the third quarter of the fiscal year ended September 30, 2016 , as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bret J. Eckert, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

August 3, 2016

/s/ BRET J. ECKERT

Bret J. Eckert
Senior Vice President and
Chief Financial Officer

A signed original of this written statement has been provided to Atmos Energy Corporation and will be retained by Atmos Energy Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

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

Form 10-Q

(Mark One)

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

For the quarterly period ended December 31, 2016

or

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

For the transition period from to

Commission File Number 1-10042

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

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of February 3, 2017.

Class	Shares Outstanding
No Par Value	105,175,480

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	December 31, 2016	September 30, 2016
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 10,492,625	$ 10,142,506
Less accumulated depreciation and amortization	1,939,663	1,873,900
Net property, plant and equipment	8,552,962	8,268,606
Current assets		
Cash and cash equivalents	44,624	47,534
Accounts receivable, net	458,813	215,880
Gas stored underground	163,763	179,070
Current assets of disposal group classified as held for sale	235,482	151,117
Other current assets	76,750	88,085
Total current assets	979,432	681,686
Goodwill	729,673	726,962
Noncurrent assets of disposal group classified as held for sale	—	28,616
Deferred charges and other assets	317,088	305,019
	$ 10,579,155	$ 10,010,889
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: December 31, 2016 — 105,109,905 shares; September 30, 2016 — 103,930,560 shares	$ 526	$ 520
Additional paid-in capital	2,451,277	2,388,027
Accumulated other comprehensive loss	(92,654)	(188,022)
Retained earnings	1,339,826	1,262,534
Shareholders' equity	3,698,975	3,463,059
Long-term debt	2,314,199	2,188,779
Total capitalization	6,013,174	5,651,838
Current liabilities		
Accounts payable and accrued liabilities	268,647	196,485
Current liabilities of disposal group classified as held for sale	109,298	72,900
Other current liabilities	381,123	439,085
Short-term debt	940,747	829,811
Current maturities of long-term debt	250,000	250,000
Total current liabilities	1,949,815	1,788,281
Deferred income taxes	1,725,433	1,603,056
Regulatory cost of removal obligation	430,407	424,281
Pension and postretirement liabilities	301,715	297,743
Noncurrent liabilities of disposal group held for sale	—	316
Deferred credits and other liabilities	158,611	245,374
	$ 10,579,155	$ 10,010,889

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended December 31	
	2016	2015
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Distribution segment	$ 754,656	$ 649,443
Pipeline and storage segment	109,952	98,416
Intersegment eliminations	(84,440)	(73,106)
	780,168	674,753
Purchased gas cost		
Distribution segment	395,346	313,991
Pipeline and storage segment	355	(559)
Intersegment eliminations	(84,396)	(73,106)
	311,305	240,326
Gross profit	468,863	434,427
Operating expenses		
Operation and maintenance	124,938	119,828
Depreciation and amortization	76,958	70,656
Taxes, other than income	57,049	51,214
Total operating expenses	258,945	241,698
Operating income	209,918	192,729
Miscellaneous expense, net	(994)	(879)
Interest charges	31,030	29,537
Income from continuing operations before income taxes	177,894	162,313
Income tax expense	63,856	60,767
Income from continuing operations	114,038	101,546
Income from discontinued operations, net of tax ($6,841 and $885)	10,994	1,315
Net Income	$ 125,032	$ 102,861
Basic and diluted net income per share		
Income per share from continuing operations	$ 1.08	$ 0.99
Income per share from discontinued operations	0.11	0.01
Net income per share - basic and diluted	$ 1.19	$ 1.00
Cash dividends per share	$ 0.45	$ 0.42
Basic and diluted weighted average shares outstanding	105,284	102,713

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended December 31	
	2016	2015
	(Unaudited) (In thousands)	
Net income	$ 125,032	$ 102,861
Other comprehensive income (loss), net of tax		
Net unrealized holding losses on available-for-sale securities, net of tax of $476 and $442	(828)	(768)
Cash flow hedges:		
Amortization and unrealized gain on interest rate agreements, net of tax of $52,429 and $2,749	91,214	4,783
Net unrealized gains on commodity cash flow hedges, net of tax of $3,183 and $1,505	4,982	2,353
Total other comprehensive income	95,368	6,368
Total comprehensive income	$ 220,400	$ 109,229

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
	2016	2015
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 125,032	$ 102,861
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	77,143	71,239
Deferred income taxes	67,241	59,299
Discontinued cash flow hedging for natural gas marketing commodity contracts	(10,579)	—
Other	4,842	3,471
Net assets / liabilities from risk management activities	3,969	(7,495)
Net change in operating assets and liabilities	(150,685)	(159,234)
Net cash provided by operating activities	116,963	70,141
Cash Flows From Investing Activities		
Capital expenditures	(297,962)	(290,412)
Acquisition	(85,714)	—
Available-for-sale securities activities, net	(10,263)	(2,263)
Other, net	1,802	2,382
Net cash used in investing activities	(392,137)	(290,293)
Cash Flows From Financing Activities		
Net increase in short-term debt	110,936	305,309
Net proceeds from equity offering	49,400	—
Issuance of common stock through stock purchase and employee retirement plans	8,998	8,729
Proceeds from issuance of long-term debt	125,000	—
Interest rate agreements cash collateral	25,670	—
Cash dividends paid	(47,740)	(43,636)
Net cash provided by financing activities	272,264	270,402
Net increase (decrease) in cash and cash equivalents	(2,910)	50,250
Cash and cash equivalents at beginning of period	47,534	28,653
Cash and cash equivalents at end of period	$ 44,624	$ 78,903

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
December 31, 2016

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") is engaged primarily in the regulated natural gas distribution and pipeline business. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states our regulated divisions and subsidiaries operate.

Our distribution business delivers natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six natural gas distribution divisions, which at December 31, 2016, covered service areas located in eight states. In addition, we transport natural gas for others through our distribution system.

Our pipeline and storage business includes the transportation of natural gas to our North Texas and Louisiana distribution systems and the management of our underground storage facilities used to support our North Texas distribution business.

Through December 31, 2016, Atmos Energy was also engaged in certain nonregulated businesses. As more fully described in Note 6, effective January 1, 2017, we sold all of the equity interests of Atmos Energy Marketing, LLC (AEM) to CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy Inc. As a result of the sale, Atmos Energy has fully exited the nonregulated gas marketing business. Additionally, as further described in Note 3, we modified our reporting segments as a result of the sale.

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, 2016. 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, 2016. Because of seasonal and other factors, the results of operations for the three-month period ended December 31, 2016 are not indicative of our results of operations for the full 2017 fiscal year, which ends September 30, 2017.

Except for the completion of the sale of AEM on January 3, 2017, as discussed in Note 6, 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, 2016.

As discussed in Note 3, due to the realignment of our reportable segments, prior periods' segment information has been recast in accordance with applicable accounting guidance. Additionally, as discussed in Note 6, due to the sale of AEM, prior period amounts have been presented as discontinued operations. The segment realignment and the presentation of discontinued operations do not impact our reported net income, financial position and cash flows.

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, an entity 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 may need to use more judgment and make more estimates than under current guidance. The new guidance will become effective for us 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.

As of December 31, 2016, we substantially completed the evaluation of our sources of revenue and are currently assessing the effect that the new guidance will have on our financial position, results of operations and cash flows. The conclusion of our assessment is contingent, in part, upon the completion of deliberations currently in progress by our industry, notably in connection with efforts to produce an accounting guide intended to be developed by the American Institute of Certified Public Accountants (AICPA).

In association with this undertaking, the AICPA formed a number of industry task forces, including a Power & Utilities (P&U) Task Force. Industry representatives and organizations, the largest auditing firms, the AICPA's Revenue Recognition Working Group and its Financial Reporting Executive Committee have undertaken, and continue to undertake, consideration of several items relevant to our industry as further discussed below. Where applicable or necessary, the FASB's Transition Resource Group (TRG) is also participating.

Currently, the industry is working to address several items including 1) the evaluation of collectability from customers if a utility has regulatory mechanisms to help assure recovery of uncollected accounts from ratepayers; 2) the accounting for funds received from third parties to partially or fully reimburse the cost of construction of an asset and 3) the accounting for alternative revenue programs, such as performance-based ratemaking. Existing alternative revenue program guidance, though excluded by the FASB in updating specific guidance associated with revenue from contracts with customers, was relocated without substantial modification to accounting guidance for rate-regulated entities. It will require separate presentation of such revenues (subject to the above-noted deliberations) in the statement of income, effective at the same time as updated guidance associated with revenue from contracts with customers becomes effective.

Currently, a timeline for the resolution of these deliberations has not been established. Additionally, we are actively working with our peers in the rate-regulated natural gas industry to conclude on the accounting treatment for several other issues that are not expected to be addressed by the P&U Task Force. Given the uncertainty with respect to the conclusions that might arise from these deliberations, we are currently unable to determine the effect the new guidance will have on our financial position, results of operations, cash flows, business processes or the transition method we will utilize to adopt the new guidance.

In May 2015, the FASB issued guidance removing the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. The guidance was effective for us on October 1, 2016 to be applied retrospectively. We measure certain pension plan assets using the net asset value per share practical expedient which are disclosed on an annual basis in our Form 10-K. The adoption of the new standard will have no impact on our results of operations, consolidated balance sheets or cash flows.

In January 2016, the FASB issued guidance related to the classification and measurement of financial instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning October 1, 2018; limited early adoption is permitted. We are currently evaluating the potential impact of this new guidance.

In February 2016, the FASB issued a comprehensive new leasing standard that will require lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The new standard will be effective for us beginning on October 1, 2019; early adoption is permitted. The new leasing standard requires modified retrospective transition, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. We are currently evaluating the effect on our financial position, results of operations and cash flows.

In June 2016, the FASB issued new guidance which will require credit losses on most financial assets measured at amortized cost and certain other instruments to be measured using an expected credit loss model. Under this model, entities will estimate credit losses over the entire contractual term of the instrument from the date of initial recognition of that instrument. In contrast, current U.S. GAAP is based on an incurred loss model that delays recognition of credit losses until it is probable the loss has been incurred. The new guidance also introduces a new impairment recognition model for available-for-sale securities that will require credit losses for available-for-sale debt securities to be recorded through an allowance account. The new standard will be effective for us beginning on October 1, 2021; early adoption is permitted beginning on October 1, 2019. We are currently evaluating the potential impact of this new guidance.

In January 2017, the FASB issued new guidance that simplifies the accounting for goodwill impairments by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the total amount of goodwill allocated to that reporting unit. The new standard will be effective for our fiscal 2021 goodwill impairment test; however, early adoption is permitted for goodwill impairment tests performed on testing dates after January 1, 2017. The adoption of the new standard will have no impact on our results of operations, consolidated balance sheets or cash flows.

Regulatory assets and liabilities

Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates. We record certain costs as regulatory assets when future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process.

Substantially all of our regulatory assets are recorded as a component of deferred charges and other assets and substantially all of our regulatory liabilities are recorded as a component of deferred credits and other liabilities. Deferred gas costs are recorded either in other current assets or liabilities and the regulatory cost of removal obligation is reported separately.

Significant regulatory assets and liabilities as of December 31, 2016 and September 30, 2016 included the following:

	December 31, 2016	September 30, 2016
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs(1)	$ 128,947	$ 132,348
Infrastructure mechanisms(2)	49,098	42,719
Deferred gas costs	18,345	45,184
Recoverable loss on reacquired debt	13,122	13,761
Deferred pipeline record collection costs	8,125	7,336
APT annual adjustment mechanism	5,194	7,171
Rate case costs	1,460	1,539
Other	13,030	13,565
	$ 237,321	$ 263,623
Regulatory liabilities:		
Regulatory cost of removal obligations	$ 479,667	$ 476,891
Deferred gas costs	17,416	20,180
Asset retirement obligations	13,404	13,404
Other	6,920	4,250
	$ 517,407	$ 514,725

(1) Includes $12.1 million and $12.4 million of pension and postretirement expense deferred pursuant to regulatory authorization.

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

3. Segment Information

Through November 30, 2016, our consolidated operations were managed and reviewed through three segments:

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

As a result of the announced sale of Atmos Energy Marketing, we revised the information used by the chief operating decision maker to manage the Company, effective December 1, 2016. Accordingly, we will manage and review our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states and storage assets located in Kentucky and Tennessee, which are used to support our natural gas distribution operations in those states. These storage assets were formerly included in our nonregulated segment.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana which were formerly included in our nonregulated segment.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

Our determination of reportable segments considers how our chief operating decision maker allocates resources between our strategic operating units under which we manage sales of various products and services through our distribution, pipeline and storage and natural gas marketing businesses. Although our distribution segment operations are geographically dispersed, they are aggregated and reported as a single segment as each natural gas distribution division has similar economic characteristics. In addition, the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana have similar economic characteristics and have been aggregated and reported as a single segment.

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, 2016. We evaluate performance based on net income or loss of the respective operating segments. We allocate interest and pension expense to the pipeline and storage segment; however, there is no debt or pension liability recorded on the pipeline and storage segment balance sheet. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Prior periods' segment information has been recast as required by applicable accounting guidance. The segment realignment does not impact our reported consolidated revenues or net income.

Income statements for the three months ended December 31, 2016 and 2015 by segment are presented in the following tables:

	Three Months Ended December 31, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 754,266	$ 25,902	$ —	$ —	$ 780,168
Intersegment revenues	390	84,050	—	(84,440)	—
	754,656	109,952	—	(84,440)	780,168
Purchased gas cost	395,346	355	—	(84,396)	311,305
Gross profit	359,310	109,597	—	(44)	468,863
Operating expenses					
Operation and maintenance	92,714	32,268	—	(44)	124,938
Depreciation and amortization	61,157	15,801	—	—	76,958
Taxes, other than income	50,546	6,503	—	—	57,049
Total operating expenses	204,417	54,572	—	(44)	258,945
Operating income	154,893	55,025	—	—	209,918
Miscellaneous expense	(633)	(361)	—	—	(994)
Interest charges	21,118	9,912	—	—	31,030
Income from continuing operations before income taxes	133,142	44,752	—	—	177,894
Income tax expense	47,778	16,078	—	—	63,856
Income from continuing operations	85,364	28,674	—	—	114,038
Income from discontinued operations, net of tax	—	—	10,994	—	10,994
Net income	$ 85,364	$ 28,674	$ 10,994	$ —	$ 125,032
Capital expenditures	$ 222,484	$ 75,478	$ —	$ —	$ 297,962

	Three Months Ended December 31, 2015				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 649,113	$ 25,640	$ —	$ —	$ 674,753
Intersegment revenues	330	72,776	—	(73,106)	—
	649,443	98,416	—	(73,106)	674,753
Purchased gas cost	313,991	(559)	—	(73,106)	240,326
Gross profit	335,452	98,975	—	—	434,427
Operating expenses					
Operation and maintenance	92,189	27,639	—	—	119,828
Depreciation and amortization	57,614	13,042	—	—	70,656
Taxes, other than income	45,558	5,656	—	—	51,214
Total operating expenses	195,361	46,337	—	—	241,698
Operating income	140,091	52,638	—	—	192,729
Miscellaneous expense	(477)	(402)	—	—	(879)
Interest charges	20,390	9,147	—	—	29,537
Income from continuing operations before income taxes	119,224	43,089	—	—	162,313
Income tax expense	45,288	15,479	—	—	60,767
Income from continuing operations	73,936	27,610	—	—	101,546
Income from discontinued operations, net of tax	—	—	1,315	—	1,315
Net income	$ 73,936	$ 27,610	$ 1,315	$ —	$ 102,861
Capital expenditures	$ 165,407	$ 124,981	$ 24	$ —	$ 290,412

Balance sheet information at December 31, 2016 and September 30, 2016 by segment is presented in the following tables:

	December 31, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 6,362,710	$ 2,190,252	$ —	$ —	$ 8,552,962
Investment in subsidiaries	834,469	—	—	(834,469)	—
Current assets					
Cash and cash equivalents	43,733	—	891	—	44,624
Assets from risk management activities	8,057	—	—	—	8,057
Current assets of disposal group classified as held for sale	—	—	253,950	(18,468)	235,482
Other current assets	666,474	46,009	(6,824)	(14,390)	691,269
Intercompany receivables	1,052,199	—	—	(1,052,199)	—
Total current assets	1,770,463	46,009	248,017	(1,085,057)	979,432
Goodwill	586,661	143,012	—	—	729,673
Noncurrent assets from risk management activities	1,282	—	—	—	1,282
Deferred charges and other assets	289,224	26,582	—	—	315,806
	$ 9,844,809	$ 2,405,855	$ 248,017	$ (1,919,526)	$ 10,579,155
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,698,975	$ 731,631	$ 102,838	$ (834,469)	$ 3,698,975
Long-term debt	2,314,199	—	—	—	2,314,199
Total capitalization	6,013,174	731,631	102,838	(834,469)	6,013,174
Current liabilities					
Current maturities of long-term debt	250,000	—	—	—	250,000
Short-term debt	940,747	—	—	—	940,747
Liabilities from risk management activities	25,060	—	—	—	25,060
Current liabilities of disposal group classified as held for sale	—	—	120,566	(11,268)	109,298
Other current liabilities	602,247	43,028	1,025	(21,590)	624,710
Intercompany payables	—	1,048,091	4,108	(1,052,199)	—
Total current liabilities	1,818,054	1,091,119	125,699	(1,085,057)	1,949,815
Deferred income taxes	1,156,716	560,401	8,316	—	1,725,433
Noncurrent liabilities from risk management activities	97,921	—	—	—	97,921
Regulatory cost of removal obligation	407,767	22,640	—	—	430,407
Pension and postretirement liabilities	301,715	—	—	—	301,715
Deferred credits and other liabilities	49,462	64	11,164	—	60,690
	$ 9,844,809	$ 2,405,855	$ 248,017	$ (1,919,526)	$ 10,579,155

	September 30, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 6,208,465	$ 2,060,141	$ —	$ —	$ 8,268,606
Investment in subsidiaries	768,415	—	—	(768,415)	—
Current assets					
Cash and cash equivalents	22,117	—	25,417	—	47,534
Assets from risk management activities	3,029	—	—	—	3,029
Current assets of disposal group classified as held for sale	—	—	162,508	(11,391)	151,117
Other current assets	486,934	39,078	5	(46,011)	480,006
Intercompany receivables	971,665	—	—	(971,665)	—
Total current assets	1,483,745	39,078	187,930	(1,029,067)	681,686
Goodwill	583,950	143,012	—	—	726,962
Noncurrent assets from risk management activities	1,822	—	—	—	1,822
Noncurrent assets of disposal group classified as held for sale	—	—	28,785	(169)	28,616
Deferred charges and other assets	275,418	27,779	—	—	303,197
	$ 9,321,815	$ 2,270,010	$ 216,715	$ (1,797,651)	$ 10,010,889
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,463,059	$ 701,818	$ 66,597	$ (768,415)	$ 3,463,059
Long-term debt	2,188,779	—	—	—	2,188,779
Total capitalization	5,651,838	701,818	66,597	(768,415)	5,651,838
Current liabilities					
Current maturities of long-term debt	250,000	—	—	—	250,000
Short-term debt	829,811	—	35,000	(35,000)	829,811
Liabilities from risk management activities	56,771	1,967	—	(1,967)	56,771
Current liabilities of the disposal group classified as held for sale	—	—	81,908	(9,008)	72,900
Other current liabilities	549,019	37,944	3,263	(11,427)	578,799
Intercompany payables	—	957,526	14,139	(971,665)	—
Total current liabilities	1,685,601	997,437	134,310	(1,029,067)	1,788,281
Deferred income taxes	1,055,348	543,390	4,318	—	1,603,056
Noncurrent liabilities from risk management activities	184,048	169	—	(169)	184,048
Regulatory cost of removal obligation	397,162	27,119	—	—	424,281
Pension and postretirement liabilities	297,743	—	—	—	297,743
Noncurrent liabilities of disposal group classified as held for sale	—	—	316	—	316
Deferred credits and other liabilities	50,075	77	11,174	—	61,326
	$ 9,321,815	$ 2,270,010	$ 216,715	$ (1,797,651)	$ 10,010,889

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three months ended December 31, 2016 and 2015 are calculated as follows:

	Three Months Ended December 31, 2015	
	2016	2015
	(In thousands, except per share amounts)	
Basic and Diluted Earnings Per Share from continuing operations		
Income from continuing operations	$ 114,038	$ 101,546
Less: Income from continuing operations allocated to participating securities	153	170
Income from continuing operations available to common shareholders	$ 113,885	$ 101,376
Basic and diluted weighted average shares outstanding	105,284	102,713
Income from continuing operations per share — Basic and Diluted	$ 1.08	$ 0.99
Basic and Diluted Earnings Per Share from discontinued operations		
Income from discontinued operations	$ 10,994	$ 1,315
Less: Income from discontinued operations allocated to participating securities	14	1
Income from discontinued operations available to common shareholders	$ 10,980	$ 1,314
Basic and diluted weighted average shares outstanding	105,284	102,713
Income from discontinued operations per share — Basic and Diluted	$ 0.11	$ 0.01
Net income per share — Basic and Diluted	$ 1.19	$ 1.00

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, 2016. Except as noted below, there were no material changes in the terms of our debt instruments during the three months ended December 31, 2016.

Long-term debt at December 31, 2016 and September 30, 2016 consisted of the following:

	December 31, 2016	September 30, 2016
	(In thousands)	
Unsecured 6.35% Senior Notes, due June 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	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
Floating-rate term loan, due 2019	125,000	—
Total long-term debt	2,585,000	2,460,000
Less:		
Original issue discount on unsecured senior notes and debentures	4,184	4,270
Debt issuance cost	16,617	16,951
Current maturities	250,000	250,000
	$ 2,314,199	$ 2,188,779

On September 22, 2016, we entered into a three year, $200 million multi-draw floating-rate term loan agreement with a syndicate of three lenders. Borrowings under the term loan may be made in increments of $1.0 million or higher, may be repaid at any time during the loan period and will bear interest at a rate dependent upon our credit ratings at the time of such borrowing and based, at our election, on a base rate or LIBOR for the applicable interest period. The term loan will be used to refinance existing indebtedness and for working capital, capital expenditures and other general corporate purposes. At December 31, 2016, there was $125.0 million outstanding under the term loan.

We utilize short-term debt 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 $1.5 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide approximately $1.6 billion of total working capital funding. The primary source of our funding is our commercial paper program, which is supported by a five-year unsecured $1.5 billion credit facility that expires September 25, 2021. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 1.25 percent, based on the Company's credit ratings. Additionally, the facility contains a $250 million accordion feature, which provides the opportunity to increase the total committed loan to $1.75 billion. This facility was amended in October 2016 to increase the total availability from $1.25 billion. At December 31, 2016 and September 30, 2016 a total of $940.7 million and $829.8 million was outstanding under our commercial paper program.

Additionally, we have a $25 million unsecured facility and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. At December 31, 2016, there were no borrowings outstanding under either of these facilities; however, outstanding letters of credit reduced the total amount available to us under our $10 million revolving facility to $4.1 million.

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At December 31, 2016, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 50 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.

These credit facilities and our public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers. Additionally, our public debt indentures relating to our senior notes and debentures, as well as certain of our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. We were in compliance with all of our debt covenants as of December 31, 2016. 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.

As of December 31, 2016, AEM had one uncommitted $25 million 364-day bilateral credit facility that was scheduled to expire on July 31, 2017 and one committed $15 million 364-day bilateral credit facility that was scheduled to expire on September 30, 2017. In connection with the sale of AEM discussed in Note 6, both facilities were terminated on January 3, 2017. There were no amounts outstanding under these facilities as of December 31, 2016.

6. Divestitures and Acquisitions

Divestiture of Atmos Energy Marketing (AEM)

On October 29, 2016, we entered into a Membership Interest Purchase Agreement (the Agreement) with CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy, Inc. (CES) to sell all of the equity interests of AEM. The transaction closed on January 3, 2017, with an effective date of January 1, 2017. CES paid a cash purchase price of $38.3 million plus estimated working capital of $103.2 million for total cash consideration of $141.5 million. Of this amount, $7.0 million was placed into escrow and will be paid to the Company within 24 months, net of any indemnification claims agreed upon between the two companies. We expect to recognize a net gain of $0.03 per diluted share on the sale and complete the working capital true–up during the second quarter of fiscal 2017.

The operating results of our natural gas marketing reportable segment have been reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Accordingly, expenses related to allocable general corporate overhead and interest expense are not included in these results. The decision to report this segment as a discontinued operation was predicated, in part, on the following qualitative and quantitative factors: 1) the disposal results in the company becoming a fully regulated entity; 2) the fact that an entire reportable segment will be disposed and 3) the fact the disposed segment represented in excess of 30 percent of consolidated revenues over the last five fiscal years.

The tables below set forth selected financial and operational information related to assets, liabilities and operating results related to discontinued operations. Additionally, assets and liabilities related to our natural gas marketing operations are classified as "held for sale" in other current assets and liabilities in our condensed consolidated balance sheets at December 31, 2016 and in other current assets, deferred charges and other assets, other current liabilities and deferred credits and other liabilities in our consolidated balance sheets at September 30, 2016. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported consolidated net income.

The following table presents statement of income data related to discontinued operations.

	Three Months Ended December 31 2016	2015
	(In thousands)	
Operating revenues	$ 303,474	$ 259,258
Purchased gas cost	277,554	249,789
Gross profit	25,920	9,469
Operating expenses	7,874	5,993
Operating income	18,046	3,476
Other nonoperating expense	(211)	(1,276)
Income from discontinued operations before income taxes	17,835	2,200
Income tax expense	6,841	885
Net income from discontinued operations	$ 10,994	$ 1,315

The following table presents a reconciliation of the carrying amounts of major classes of assets and liabilities of our natural gas marketing's operations to total assets and liabilities classified as held for sale.

	December 31, 2016	September 30, 2016
	(In thousands)	
Assets:		
Net property, plant and equipment	$ 11,599	$ 11,905
Accounts receivable	139,741	93,551
Gas stored underground	77,559	54,246
Other current assets	9,447	14,711
Goodwill[(2)]	13,734	16,445
Deferred charges and other assets	1,870	435
Total assets of the disposal group classified as held for sale in the statement of financial position [(1)]	253,950	191,293
Cash	891	25,417
Other assets	(6,824)	5
Total assets of disposal group in the statement of financial position	$ 248,017	$ 216,715
Liabilities:		
Accounts payable and accrued liabilities	$ 113,368	$ 72,268
Other current liabilities	6,876	9,640
Deferred credits and other	322	316
Total liabilities of the disposal group classified as held for sale in the statement of financial position [(1)]	120,566	82,224
Intercompany note payable	—	35,000
Tax liabilities	19,469	15,471
Intercompany payables	4,108	14,139
Other liabilities	1,036	3,179
Total liabilities of disposal group in the statement of financial position	$ 145,179	$ 150,013

(1) Amounts in the comparative period are classified as current and long term in the statement of financial position.

(2) The period-over-period change in natural gas marketing goodwill is the result of the reallocation of goodwill between the retained portion and held-for-sale portion of the former Atmos Energy Marketing reporting unit, based on relative fair value.

The following table presents statement of cash flow data related to discontinued operations.

	Three Months Ended December 31	
	2016	2015
	(In thousands)	
Depreciation and amortization	$ 185	$ 583
Capital expenditures	$ —	$ 24
Noncash gain in commodity contract cash flow hedges	$ 18,744	$ 3,858

Acquisition of EnLink Pipeline

On December 20, 2016, we executed a purchase and sale agreement to acquire the general partnership and limited partnership interests in EnLink North Texas Pipeline, LP (EnLink Pipeline) from EnLink Energy GP, LLC and EnLink Midstream Operating, LP for an all–cash price of $85 million, plus estimated working capital. After considering estimated working capital, the total proceeds paid were $85.7 million. The final purchase is subject to adjustment after the estimated working capital is finalized during the second quarter of fiscal 2017.

EnLink Pipeline's primary asset is a 140–mile natural gas pipeline located on the north side of the Dallas–Fort Worth Metroplex. As of December 31, 2016, the $85 million purchase price was preliminarily allocated, based on fair value using observable market inputs, to the net book value of the acquired pipeline. The final purchase price allocation is subject to adjustment pending the completion of analysis of the fair value of certain contracts included in the acquisition. We expect to complete this evaluation during the second quarter of fiscal 2017.

7. Shareholders' Equity

Shelf Registration and At-the-Market Equity Sales Program

On March 28, 2016, we filed a registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue, from time to time, up to $2.5 billion in common stock and/or debt securities. We also filed a prospectus supplement under the registration statement relating to an at-the-market (ATM) equity distribution program under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. During the first fiscal quarter of 2017, we sold 690,812 shares of common stock under our existing ATM program for $50.0 million and received net proceeds of $49.4 million. At December 31, 2016, approximately $2.4 billion of securities remain available for issuance under the shelf registration statement and approximately $50 million of equity remained available for issuance under the ATM program.

Accumulated Other Comprehensive Income (Loss)

We record deferred gains (losses) in AOCI related to available-for-sale securities, interest rate 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 (loss).

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2016	$ 4,484	$ (187,524)	$ (4,982)	$ (188,022)
Other comprehensive income (loss) before reclassifications	(828)	91,127	9,847	100,146
Amounts reclassified from accumulated other comprehensive income	—	87	(4,865)	(4,778)
Net current-period other comprehensive income (loss)	(828)	91,214	4,982	95,368
December 31, 2016	$ 3,656	$ (96,310)	$ —	$ (92,654)

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2015	$ 4,949	$ (88,842)	$ (25,437)	$ (109,330)
Other comprehensive income (loss) before reclassifications	(768)	4,696	(11,656)	(7,728)
Amounts reclassified from accumulated other comprehensive income	—	87	14,009	14,096
Net current-period other comprehensive income (loss)	(768)	4,783	2,353	6,368
December 31, 2015	$ 4,181	$ (84,059)	$ (23,084)	$ (102,962)

The following tables detail reclassifications out of AOCI for the three months ended December 31, 2016 and 2015. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended December 31, 2016	
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**	**Affected Line Item in the Statement of Income**
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$ (137)	Interest charges
Commodity contracts	7,976	Purchased gas cost[1]
	7,839	Total before tax
	(3,061)	Tax expense
Total reclassifications	$ 4,778	Net of tax

	Three Months Ended December 31, 2015	
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**	**Affected Line Item in the Statement of Income**
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$ (137)	Interest charges
Commodity contracts	(22,965)	Purchased gas cost[1]
	(23,102)	Total before tax
	9,006	Tax benefit
Total reclassifications	$ (14,096)	Net of tax

[1]Amounts are presented as part of income from discontinued operations on the condensed consolidated statements of income.

8. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three months ended December 31, 2016 and 2015 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.

	Three Months Ended December 31			
	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 5,216	$ 4,698	$ 3,109	$ 2,706
Interest cost	6,297	7,095	2,670	3,106
Expected return on assets	(6,994)	(6,881)	(1,796)	(1,566)
Amortization of transition obligation	—	—	—	21
Amortization of prior service credit	(58)	(57)	(411)	(411)
Amortization of actuarial (gain) loss	4,249	3,320	(707)	(542)
Net periodic pension cost	$ 8,710	$ 8,175	$ 2,865	$ 3,314

The assumptions used to develop our net periodic pension cost for the three months ended December 31, 2016 and 2015 are as follows:

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Discount rate	3.73%	4.55%	3.73%	4.55%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.00%	7.00%	4.45%	4.45%

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 plan as of January 1, 2016. Based on that determination, we were not required to make a minimum contribution to our defined benefit plan during the first quarter of fiscal 2017.

We contributed $3.0 million to our other post-retirement benefit plans during the three months ended December 31, 2016. We expect to contribute a total of between $10 million and $20 million to these plans during fiscal 2017.

9. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 11 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016, there were no material changes in the status of such litigation and environmental-related matters or claims during the three months ended December 31, 2016.

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

Our Mid-Tex Division 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. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. There were no material changes to the purchase commitments for the three months ended December 31, 2016.

Regulatory Matters

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

As of December 31, 2016, formula rate mechanisms were in progress in our Louisiana, Tennessee, Mississippi and West Texas service areas, infrastructure mechanisms were in progress in our Mississippi, Colorado and Kansas service areas and an ad valorem tax rider filing was in progress in our Kansas service area. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

10. Financial Instruments

We currently use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments and the related accounting for these financial instruments are fully described in Notes 2 and 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. During the three months ended December 31, 2016 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 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 2016-2017 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we anticipate hedging approximately 27 percent, or 16.2 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Natural Gas Marketing Commodity Risk Management Activities

Our natural gas marketing segment was 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. Through December 31, 2016, we managed 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. These financial instruments have maturity dates ranging from one to 60 months. Effective January 1, 2017, as a result of the sale of AEM, these activities will be discontinued.

Due to the anticipated sale of AEM, we determined that the cash flows associated with our natural gas marketing commodity cash flow hedges were no longer probable of occurring; therefore, we discontinued hedge accounting as of December 31, 2016. As a result, we reclassified the gain in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of purchased gas costs and recognized a pre-tax gain of $10.6 million for the three months ended December 31, 2016, which is included in discontinued operations on the condensed consolidated statement of income.

Interest Rate Risk Management Activities

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

As of December 31, 2016, 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 December 31, 2016, we had $18.2 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 December 31, 2016, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of December 31, 2016, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Quantity (MMcf)
Commodity contracts	Fair Value	(22,403)
	Not designated	109,012
		86,609

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments as of December 31, 2016 and September 30, 2016. 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	Assets	Liabilities
		(In thousands)	
December 31, 2016			
Designated As Hedges:			
Commodity contracts	Other current liabilities	$ —	$ (19,740)
Interest rate contracts	Other current liabilities	—	(25,060)
Interest rate contracts	Deferred credits and other liabilities	—	(97,921)
Total		—	(142,721)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	89,309	(71,433)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	19,714	(16,591)
Total		109,023	(88,024)
Gross Financial Instruments		109,023	(230,745)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		(97,841)	97,841
Net Financial Instruments		11,182	(132,904)
Cash collateral		3,788	9,909
Net Assets/Liabilities from Risk Management Activities		$ 14,970	$ (122,995)

	Balance Sheet Location	Assets	Liabilities
		(In thousands)	
September 30, 2016			
Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	$ 6,612	$ (21,903)
Interest rate contracts	Other current assets / Other current liabilities	—	(68,481)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	2,178	(3,779)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(198,008)
Total		8,790	(292,171)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	21,186	(18,812)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	14,165	(12,701)
Total		35,351	(31,513)
Gross Financial Instruments		44,141	(323,684)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		(39,290)	39,290
Net Financial Instruments		4,851	(284,394)
Cash collateral		6,775	43,575
Net Assets/Liabilities from Risk Management Activities		$ 11,626	$ (240,819)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our natural gas marketing segment is recorded as a component of purchased gas cost, which is included in discontinued operations on the condensed consolidated statements of income, and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended December 31, 2016 and 2015, we recognized gains arising from fair value and cash flow hedge ineffectiveness of $3.4 million and $7.9 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our natural gas marketing segment commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three months ended December 31, 2016 and 2015 is presented below.

	Three Months Ended December 31	
	2016	2015
	(In thousands)	
Commodity contracts	$ (9,567)	$ 5,744
Fair value adjustment for natural gas inventory designated as the hedged item	12,858	2,161
Total decrease in purchased gas cost	$ 3,291	$ 7,905
The decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$ (597)	$ 1,289
Timing ineffectiveness	3,888	6,616
	$ 3,291	$ 7,905

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 our interest rate and natural gas marketing segment cash flow hedges on our condensed consolidated income statements for the three months ended December 31, 2016 and 2015 is presented below.

	Three Months Ended December 31	
	2016	2015
	(In thousands)	
Loss reclassified from AOCI for effective portion of commodity contracts	$ (2,612)	$ (22,965)
Gain (loss) arising from ineffective portion of commodity contracts	111	(43)
Gain on discontinuance of cash flow hedging of natural gas marketing commodity contracts reclassified from AOCI	10,579	—
Total impact on purchased gas cost	8,078	(23,008)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(137)	(137)
Total Impact from Cash Flow Hedges	$ 7,941	$ (23,145)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three months ended December 31, 2016 and 2015. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended December 31	
	2016	2015
	(In thousands)	
Increase (decrease) in fair value:		
Interest rate agreements	$ 91,127	$ 4,696
Forward commodity contracts	9,847	(11,656)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate agreements	87	87
Forward commodity contracts	(4,865)	14,009
Total other comprehensive income from hedging, net of tax(1)	$ 96,196	$ 7,136

(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 natural gas marketing segment commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of December 31, 2016. 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
	(In thousands)
Next twelve months	$ (523)
Thereafter	(17,694)
Total[(1)]	$ (18,217)

(1) Utilizing an income tax rate of 37 percent.

Financial Instruments Not Designated as Hedges

The impact of natural gas marketing segment financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended December 31, 2016 and 2015 was a decrease (increase) in purchased gas cost of $6.8 million and $(2.2) million, which is included in discontinued operations on the condensed consolidated statements of income.

As discussed above, financial instruments used in our distribution segment are not designated as hedges. However, there is no earnings impact on our 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.

11. 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, 2016. During the three months ended December 31, 2016, 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 7 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2016.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2016 and September 30, 2016. Assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	December 31, 2016
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 109,023	$ —	$ (94,053)	$ 14,970
Hedged portion of gas stored underground	76,735	—	—	—	76,735
Available-for-sale securities					
Registered investment companies	38,836	—	—	—	38,836
Bond mutual funds	10,378	—	—	—	10,378
Bonds	—	31,303	—	—	31,303
Money market funds	—	1,613	—	—	1,613
Total available-for-sale securities	49,214	32,916	—	—	82,130
Total assets	$ 125,949	$ 141,939	$ —	$ (94,053)	$ 173,835
Liabilities:					
Financial instruments	$ —	$ 230,745	$ —	$ (107,750)	$ 122,995

	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, 2016
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 44,141	$ —	$ (32,515)	$ 11,626
Hedged portion of gas stored underground	52,578	—	—	—	52,578
Available-for-sale securities					
Registered investment companies	38,677	—	—	—	38,677
Bonds	—	31,394	—	—	31,394
Money market funds	—	2,630	—	—	2,630
Total available-for-sale securities	38,677	34,024	—	—	72,701
Total assets	$ 91,255	$ 78,165	$ —	$ (32,515)	$ 136,905
Liabilities:					
Financial instruments	$ —	$ 323,684	$ —	$ (82,865)	$ 240,819

(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. As of December 31, 2016, we had $13.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $9.9 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $3.8 million 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. As of September 30, 2016, we had $50.4 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $43.6 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $6.8 million is classified as current risk management assets.

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

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of December 31, 2016				
Domestic equity mutual funds	$ 27,792	$ 5,853	$ (903)	$ 32,742
Foreign equity mutual funds	5,102	992	—	6,094
Bond mutual funds	10,428	—	(50)	10,378
Bonds	31,380	19	(96)	31,303
Money market funds	1,613	—	—	1,613
	$ 76,315	$ 6,864	$ (1,049)	$ 82,130
As of September 30, 2016				
Domestic equity mutual funds	$ 26,692	$ 6,419	$ (590)	$ 32,521
Foreign equity mutual funds	4,954	1,202	—	6,156
Bonds	31,296	108	(10)	31,394
Money market funds	2,630	—	—	2,630
	$ 65,572	$ 7,729	$ (600)	$ 72,701

At December 31, 2016 and September 30, 2016, our available-for-sale securities included $40.4 million and $41.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At December 31, 2016, we maintained investments in bonds that have contractual maturity dates ranging from January 2017 through September 2020.

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

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of December 31, 2016 and September 30, 2016:

	December 31, 2016	September 30, 2016
	(In thousands)	
Carrying Amount	$ 2,585,000	$ 2,460,000
Fair Value	$ 2,788,228	$ 2,844,990

12. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 16 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. During the three months ended December 31, 2016, there were no material changes in our concentration of credit risk.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of December 31, 2016 and the related condensed consolidated statements of income, comprehensive income and cash flows for the three-month periods ended December 31, 2016 and 2015. 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, 2016, 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 14, 2016, 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, 2016, is fairly stated, in all material respects, in relation to the consolidated balance sheets from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
February 7, 2017

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, 2016.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit and capital 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 commodity price volatility, counterparty creditworthiness or performance and interest rate risk; 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 natural gas distribution business; increased costs of providing health care benefits along with pension and postretirement health care benefits and increased funding requirements; the inability to continue to hire, train and retain appropriate personnel; 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 climate changes or related additional legislation or regulation in the future; the inherent hazards and risks involved in operating our distribution and pipeline and storage businesses; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses, as well as our natural gas marketing business through December 31, 2016. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six natural gas distribution divisions, which at December 31, 2016 covered service areas located in eight states. In addition, we transport natural gas for others through our distribution and pipeline systems.

Through our natural gas marketing businesses, we have provided natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast.

As discussed in Note 3, beginning with the quarter ended December 31, 2016, we will manage and review our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states, and storage assets located in Kentucky and Tennessee, which are used to support our natural gas distribution operations in those states. These storage assets were formerly included in our nonregulated segment.
- The *pipeline and storage segment*, is comprised primarily of the pipeline and storage operations of our Atmos Energy Pipeline-Texas division and our natural gas transmission operations in Louisiana which were formerly included in our nonregulated segment..
- The *natural gas marketing segment*, is comprised of our discontinued natural gas marketing business.

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, 2016 and include the following:

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

Our critical accounting policies are reviewed periodically by the Audit Committee of our Board of Directors. There were no significant changes to these critical accounting policies during the three months ended December 31, 2016.

RESULTS OF OPERATIONS

Executive Summary

Atmos Energy strives to operate its businesses safely and reliably while delivering superior shareholder value. In recent years, we have implemented rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved rate from customer usage patterns. Additionally, we have significantly increased investments in the safety and reliability of our natural gas distribution and transmission infrastructure. This increased level of investment and timely recovery of these investments through our regulatory mechanisms has resulted in increased earnings and operating cash flows in recent years.

The pursuit of our strategy was the primary driver for our decision to sell our nonregulated natural gas marketing business and fully exit that business. The sale was announced in October 2016 and closed in January 2017 with the receipt of $134.5 million in cash proceeds, including estimated working capital. We expect to record a net gain of $0.03 per diluted share on the sale in the second quarter of fiscal 2017. The proceeds received from the transaction will be used to fund infrastructure in our remaining businesses. As a result of the sale, the results of operations for the divested business have been presented as discontinued operations.

	Three Months Ended December 31		
	2016	2015	Change
	(In thousands, except per share data)		
Distribution operations	$ 85,364	$ 73,936	$ 11,428
Pipeline and storage operations	28,674	27,610	1,064
Net income from continuing operations	114,038	101,546	12,492
Net income from discontinued operations	10,994	1,315	9,679
Net income	$ 125,032	$ 102,861	$ 22,171
Diluted EPS from continued operations	$ 1.08	$ 0.99	$ 0.09
Diluted EPS from discontinued operations	0.11	0.01	0.10
Consolidated diluted EPS	$ 1.19	$ 1.00	$ 0.19

Net income from continuing operations increased 12.3 percent, quarter-over-quarter primarily due to positive rate outcomes and customer growth in our distribution business. During the first quarter of fiscal 2017, our distribution segment had completed three regulatory proceedings, resulting in an increase in annual operating income of $4.6 million and had nine ratemaking efforts in progress at December 31, 2016 seeking $28.9 million of additional annual operating income. Additionally, on January 6, 2017, our Atmos Pipeline - Texas Division filed its statement of intent seeking $55.2 million in additional operating income. Our discontinued natural gas marketing results improved quarter-over-quarter primarily due to a pre-tax gain of $10.6 million recognized in the current quarter related to the discontinuance of cash flow hedging for our natural gas marketing commodity contracts.

Capital expenditures for the first three months of fiscal 2017 were $298.0 million. Approximately 78 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 $1.1 billion and $1.25 billion for fiscal 2017. We funded our capital expenditure program primarily through operating cash flows of $117.0 million, $125 million in borrowings under our three-year $200 million multi-draw term loan, $49.4 million in proceeds from the issuance of common stock under our at-the-market equity distribution program and net short-term debt borrowings.

As a result of our sustained financial performance, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 7.1 percent for fiscal 2017.

Distribution Segment

The distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states, and storage assets located in Kentucky and Tennessee, which are used to support our regulated natural gas distribution operations in those states. These storage assets were previously included in our former nonregulated segment. The primary factors that impact the results of this segment 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 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 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 includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

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

Three Months Ended December 31, 2016 compared with Three Months Ended December 31, 2015

Financial and operational highlights for our distribution segment for the three months ended December 31, 2016 and 2015 are presented below.

	Three Months Ended December 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 359,310	$ 335,452	$ 23,858
Operating expenses	204,417	195,361	9,056
Operating income	154,893	140,091	14,802
Miscellaneous expense	(633)	(477)	(156)
Interest charges	21,118	20,390	728
Income before income taxes	133,142	119,224	13,918
Income tax expense	47,778	45,288	2,490
Net income	$ 85,364	$ 73,936	$ 11,428
Consolidated distribution sales volumes — MMcf	74,430	72,254	2,176
Consolidated distribution transportation volumes — MMcf	36,175	32,211	3,964
Total consolidated distribution throughput — MMcf	110,605	104,465	6,140
Consolidated distribution average cost of gas per Mcf sold	$ 5.31	$ 4.35	$ 0.96

Income for our distribution segment increased 15 percent, primarily due to a $23.9 million increase in gross profit, partially offset with a $9.1 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $15.9 million net increase in rate adjustments, primarily in our Mid-Tex, Louisiana and West Texas Divisions.
- a $2.6 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $2.2 million increase in the related tax expense.
- Customer growth, primarily in our Mid-Tex, Louisiana and Tennessee service areas, which contributed an incremental $1.7 million.

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 higher levels of pipeline maintenance and higher depreciation and property tax expense associated with increased capital investments.

Additionally, interest expense increased $0.7 million due to higher average short-term debt balances and interest rates and expense associated with $125.0 million of incremental debt financing issued during the first quarter of fiscal 2017.

The following table shows our operating income by distribution division, in order of total rate base, for the three months ended December 31, 2016 and 2015. The presentation of our distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended December 31		
	2016	2015	Change
	(In thousands)		
Mid-Tex	$ 72,743	$ 67,919	$ 4,824
Kentucky/Mid-States	22,738	19,138	3,600
Louisiana	19,863	15,843	4,020
West Texas	14,928	12,889	2,039
Mississippi	11,958	12,792	(834)
Colorado-Kansas	11,705	10,092	1,613
Other	958	1,418	(460)
Total	$ 154,893	$ 140,091	$ 14,802

Recent Ratemaking Developments

The amounts described in the following sections represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling. During the first three months of fiscal 2017, we completed three regulatory proceedings, resulting in a $4.6 million increase in annual operating income as summarized below:

Rate Action		Annual Increase to Operating Income (In thousands)
Annual formula rate mechanisms	$	4,603
Rate case filings		6
Other rate activity		
	$	4,609

Additionally, the following ratemaking efforts seeking $28.9 million in annual operating income were in progress as of December 31, 2016:

Division	Rate Action	Jurisdiction		Operating Income Requested (In thousands)
Louisiana	Formula Rate Mechanism	Trans La	$	4,392
Kentucky/Mid-States	Formula Rate Mechanism (1)	Tennessee		5,514
Mississippi	Formula Rate Mechanism (2)	Mississippi		6,292
Mississippi	Infrastructure Mechanism (3)	Mississippi		3,334
Mississippi	Infrastructure Mechanism (3)	Mississippi		1,292
Colorado-Kansas	Infrastructure Mechanism (4)	Colorado		1,350
Colorado-Kansas	Infrastructure Mechanism	Kansas		801
Colorado-Kansas	Ad Valorem Tax Rider (5)	Kansas		784
West Texas	Formula Rate Filing	WT Cities		5,152
			$	28,911

(1) The Tennessee Regulatory Authority issued a final order approving a $4.6 million increase in operating income, to be included in the Company's 2017 ARM filing, that was filed on February 1, 2017.

(2) The Mississippi Public Service Commission (MPSC) issued a final order approving a $4.4 million stable rate increase in operating income effective February 1, 2017.

(3) The MPSC issued final orders approving $4.6 million SIR and SGR increases in operating income effective January 1, 2017.

(4) The Colorado Public Utilities Commission issued a final order approving a $1.4 million increase in annual operating income effective January 1, 2017.

(5) The Kansas Corporation Commission issued a final order approving a $0.8 million increase in annual operating income effective February 1, 2017. 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.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have formula rate mechanisms in our Louisiana, Mississippi and Tennessee operations and in substantially all of our Texas divisions. Additionally, we have specific infrastructure programs in substantially all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	**Infrastructure Programs**	**Formula Rate Mechanisms**
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes (Texas only), until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following annual formula rate mechanisms were approved during the three months ended December 31, 2016.

Division	**Jurisdiction**	**Test Year Ended**	**Increase in Annual Operating Income**	**Effective Date**
			(In thousands)	
2017 Filings:				
Kentucky/Mid-States	Kentucky	09/30/2017	$ 4,981	10/14/2016
Kentucky/Mid-States	Virginia	09/30/2017	(378)	10/01/2016
Total 2017 Filings			$ 4,603	

The Louisiana Public Service Commission (LPSC) issued final orders approving a $14.9 million increase in annual operating income in the Company's 2016 formula rate filings for Trans La and LGS. These rates had been implemented in April 2016 and July 2016, subject to refund.

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 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 three months ended December 31, 2016.

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2017 Rate Case Filings:			
Kentucky/Mid-States [(1)]	Virginia	$ 6	12/27/2016
Total 2017 Rate Case Filings		$ 6	

(1) The Virginia State Corporation Commission issued a final order approving a re-basing of the Company's SAVE rates into base rates and a decrease to depreciation expense. The Company had implemented rates on April 1, 2016, subject to refund, of $0.5 million.

Other Ratemaking Activity

The Company had no other ratemaking activity during the three months ended December 31, 2016.

Pipeline and Storage Segment

Our pipeline and storage segment consists of the pipeline and storage operations of our Atmos Pipeline–Texas Division (APT) and our natural gas transmission operations in Louisiana, which were previously included in our former nonregulated segment. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. APT provides transportation and storage services to our Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, as well as marketers and producers. As part of its pipeline operations, APT manages five underground storage reservoirs in Texas.

Our natural gas transmission operations in Louisiana are comprised of a proprietary 21-mile pipeline located in New Orleans, Louisiana that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. They also manage two asset management plans with distribution affiliates of the Company which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex and Louisiana service areas. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation and storage 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 the volumes of gas transported for shippers through our pipeline system and the rates for such transportation.

The results of APT are also significantly impacted by the natural gas requirements of the Mid–Tex Division because it is the primary transporter of natural gas for our Mid–Tex Division. Additionally, its operations may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

APT annually uses GRIP to recover capital costs incurred in the prior calendar year. However, GRIP also requires a utility to file a statement of intent at least once every five years to review its costs and expenses, including capital costs filed for recovery under GRIP. On January 6, 2017, APT filed its statement of intent seeking $55.2 million in additional annual operating income. APT customarily submits an annual GRIP filing during the second fiscal quarter of each fiscal year. However, APT is precluded from submitting a GRIP filing until a final order has been issued on the statement of intent. Accordingly, APT will not be submitting its annual GRIP filing during the second quarter of fiscal 2017. The Railroad Commission of Texas has 185 days to issue a final order in this proceeding.

On December 21, 2016, the Louisiana Public Service Commission approved an annual increase of five percent to the demand fee charged by our natural gas transmission pipeline for each of the next 10 years, effective October 1, 2017. This agreement will replace the existing agreement that will expire in September 2017.

Three Months Ended December 31, 2016 compared with Three Months Ended December 31, 2015

Financial and operational highlights for our pipeline and storage segment for the three months ended December 31, 2016 and 2015 are presented below.

	Three Months Ended December 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Mid-Tex / Affiliate transportation	$ 82,483	$ 70,033	$ 12,450
Third-party transportation	22,205	22,093	112
Other	4,909	6,849	(1,940)
Gross profit	109,597	98,975	10,622
Operating expenses	54,572	46,337	8,235
Operating income	55,025	52,638	2,387
Miscellaneous expense	(361)	(402)	41
Interest charges	9,912	9,147	765
Income before income taxes	44,752	43,089	1,663
Income tax expense	16,078	15,479	599
Net income	$ 28,674	$ 27,610	$ 1,064
Gross pipeline transportation volumes — MMcf	186,780	179,852	6,928
Consolidated pipeline transportation volumes — MMcf	134,976	129,159	5,817

Net income for our pipeline and storage segment increased four percent, primarily due to a $10.6 million increase in gross profit, offset by an $8.2 million increase in operating expenses. The increase in gross profit primarily reflects a $10.8 million increase in rates from the GRIP filings approved in fiscal 2016.

Operating expenses increased $8.2 million, primarily due to increased levels of pipeline maintenance activities and higher depreciation expense and property taxes associated with increased capital investments.

Additionally, interest expense increased $0.8 million due to higher average short-term debt balances and interest rates and expense associated with $125.0 million of incremental debt financing issued during the first quarter of fiscal 2017.

Natural Gas Marketing Segment

Through December 31, 2016, we were engaged in an unregulated natural gas marketing business, which was conducted by Atmos Energy Marketing (AEM). AEM's primary business is to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. Additionally, AEM utilizes proprietary and customer–owned transportation and storage assets to provide various services its customers request. AEM serves most of its customers under contracts generally having one to two year terms. As a result, AEM's margins arise from the types of commercial transactions it has structured with its customers and its ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

As more fully described in Note 6, effective January 1, 2017, we sold all of the equity interests of AEM to CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy Inc. As a result of the sale, Atmos Energy has fully exited the nonregulated natural gas marketing business. Accordingly, these operations have been reported as discontinued operations.

Three Months Ended December 31, 2016 compared with Three Months Ended December 31, 2015

Financial and operating highlights for our natural gas marketing segment for the three months ended December 31, 2016 and 2015 are presented below.

	Three Months Ended December 31		
	2016	2015	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 25,920	$ 9,469	$ 16,451
Operating expenses	7,874	5,993	1,881
Operating income	18,046	3,476	14,570
Miscellaneous income	30	76	(46)
Interest charges	241	1,352	(1,111)
Income before income taxes	17,835	2,200	15,635
Income tax expense	6,841	885	5,956
Net income from discontinued operations	$ 10,994	$ 1,315	$ 9,679
Gross natural gas marketing delivered gas sales volumes — MMcf	90,223	93,196	(2,973)
Consolidated natural gas marketing delivered gas sales volumes — MMcf	78,646	81,594	(2,948)
Net physical position (Bcf)	18.6	21.3	(2.7)

The $9.6 million quarter-over-quarter increase in net income from discontinued operations primarily reflects the recognition of a net $6.6 million noncash gain from unwinding hedge accounting for certain of the natural gas marketing business's financial positions. Due to the anticipated sale of AEM, we determined that the cash flows associated with our natural gas marketing commodity cash flow hedges were no longer probable of occurring; therefore, we discontinued hedge accounting as of December 31, 2016. As a result, we reclassified the gains in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of purchased gas costs and recognized a pre-tax gain of $10.6 million for the three months ended December 31, 2016.

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 45 to 55 percent. We also evaluate the levels of committed borrowing capacity that we require. We currently have over $1.5 billion of capacity under 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 registration statement on file with the SEC that permits us to issue a total of $2.5 billion in common stock and/or debt securities. Under the shelf registration statement, we have filed a prospectus supplement for an at–the-market (ATM) equity distribution program under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. At December 31, 2016, approximately $2.4 billion of securities remain available for issuance under the shelf registration statement and approximately $50 million of equity remained available for issuance under the ATM program.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of December 31, 2016, September 30, 2016 and December 31, 2015:

	December 31, 2016		September 30, 2016		December 31, 2015	
	(In thousands, except percentages)					
Short-term debt	$ 940,747	13.1%	$ 829,811	12.3%	$ 763,236	11.8%
Long-term debt[(1)]	2,564,199	35.6%	2,438,779	36.2%	2,437,910	37.7%
Shareholders' equity	3,698,975	51.3%	3,463,059	51.5%	3,272,109	50.5%
Total	$ 7,203,921	100.0%	$ 6,731,649	100.0%	$ 6,473,255	100.0%

(1) In June 2017, $250 million of long-term debt will mature. We plan to issue new senior notes to replace this maturing debt. We have executed forward starting interest rate swaps to effectively fix the Treasury yield component associated with this anticipated issuance at 3.37%.

Cash Flows

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

Cash flows from operating, investing and financing activities for the three months ended December 31, 2016 and 2015 are presented below.

	Three Months Ended December 31		
	2016	2015	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 116,963	$ 70,141	$ 46,822
Investing activities	(392,137)	(290,293)	(101,844)
Financing activities	272,264	270,402	1,862
Change in cash and cash equivalents	(2,910)	50,250	(53,160)
Cash and cash equivalents at beginning of period	47,534	28,653	18,881
Cash and cash equivalents at end of period	$ 44,624	$ 78,903	$ (34,279)

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

For the three months ended December 31, 2016, we generated cash flow of $117.0 million from operating activities compared with $70.1 million for the three months ended December 31, 2015. The $46.8 million increase in operating cash flows primarily reflects favorable deferred gas cost recoveries attributable to higher sales volumes than in the prior-year quarter.

Cash flows from investing activities

In executing our regulatory strategy, we target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions 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 our ongoing construction program, which enables us to enhance the safety and reliability of the systems used to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. Over the last three fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system. We anticipate our annual capital spending will be in the range of $1 billion to $1.4 billion through fiscal 2020.

For the three months ended December 31, 2016, cash used for investing activities was $392.1 million compared to $290.3 million in the prior-year period. The $101.8 million year-over-year change is primarily due to the purchase of EnLink Pipeline for $85.7 million.

Cash flows from financing activities

For the three months ended December 31, 2016, our financing activities generated $272.3 million of cash compared with $270.4 million in the prior-year period. The $1.9 million increase of cash generated is primarily due to borrowings under our three year, $200 million multi-draw floating-rate term loan agreement, proceeds received from the issuance of common stock under our ATM program during the current quarter and the return of cash collateral related to our forward-starting interest rate swaps due to an increase in interest rates in the current period. These additional proceeds resulted in lower net short-term borrowings compared to the prior-year quarter.

The following table summarizes our share issuances for the three months ended December 31, 2016 and 2015.

	Three Months Ended December 31	
	2016	**2015**
Shares issued:		
Direct Stock Purchase Plan	27,071	35,417
1998 Long-Term Incentive Plan	365,471	458,607
Retirement Savings Plan and Trust	95,991	106,474
At-the-Market (ATM) Equity Distribution Program	690,812	—
Total shares issued	1,179,345	600,498

The year-over-year increase in the number of shares issued primarily reflects shares issued under the ATM Program.

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 $1.5 billion commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders that provide a total of approximately $1.6 billion of working capital funding. As of December 31, 2016, the amount available to us under our credit facilities, net of commercial paper and outstanding letters of credit, was $0.6 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 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 December 31, 2016, all three rating agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

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

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of December 31, 2016. 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 9 to the unaudited condensed consolidated financial statements, there were no significant changes in our contractual obligations and commercial commitments during the three months ended December 31, 2016.

Risk Management Activities

In our distribution and pipeline and storage segments, 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. Through December 31, 2016, we managed our exposure to the risk of natural gas price changes in our natural gas marketing segment by locking 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.

The following table shows the components of the change in fair value of our financial instruments for the three months ended December 31, 2016 and 2015:

	Three Months Ended December 31	
	2016	2015
	(In thousands)	
Fair value of contracts at beginning of period	$ (279,543)	$ (153,981)
Contracts realized/settled	9,963	6,268
Fair value of new contracts	963	(183)
Other changes in value	146,895	17,614
Fair value of contracts at end of period	(121,722)	(130,282)
Netting of cash collateral	13,697	39,248
Cash collateral and fair value of contracts at period end	$ (108,025)	$ (91,034)

The fair value of our financial instruments at December 31, 2016 is presented below by time period and fair value source:

Source of Fair Value	Fair Value of Contracts at December 31, 2016 — Maturity in Years: Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$ (26,924)	$ (95,506)	$ 708	$ —	$ (121,722)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (26,924)	$ (95,506)	$ 708	$ —	$ (121,722)

Pension and Postretirement Benefits Obligations

For the three months ended December 31, 2016 and 2015, our total net periodic pension and other benefits costs were $11.6 million and $11.5 million. A substantial portion of those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2017 costs were determined using a September 30, 2016 measurement date. As of September 30, 2016, interest and corporate bond rates were lower than the rates as of September 30, 2015. Therefore, we decreased the discount rate used to measure our fiscal 2017 net periodic cost from 4.55 percent to 3.73 percent. We maintained the expected return on plan assets of 7.00 percent in the determination of our fiscal 2017 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2017 net periodic pension cost to be generally consistent with fiscal 2016.

The amount with which we fund our defined benefit plan is determined in accordance with the Pension Protection Act of 2006 (PPA) and is influenced by the funded position of the plan when the funding requirements are determined on January 1 of each year. Based upon the determination as of January 1, 2016, we are not required to make a minimum contribution to our defined benefit plan during fiscal 2017. However, we will consider whether a voluntary contribution is prudent to maintain certain funding levels.

For the three months ended December 31, 2016 we contributed $3.0 million to our postretirement medical plans. We anticipate contributing a total of between $10 million and $20 million to our postretirement plans during fiscal 2017.

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

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our distribution and pipeline and storage segments for the three-month periods ended December 31, 2016 and 2015.

Distribution Sales and Statistical Data

	Three Months Ended December 31	
	2016	2015
METERS IN SERVICE, end of period		
Residential	2,923,480	2,891,676
Commercial	268,574	265,766
Industrial	1,693	1,839
Public authority and other	8,359	8,421
Total meters	3,202,106	3,167,702
INVENTORY STORAGE BALANCE — Bcf	56.7	58.5
SALES VOLUMES — MMcf[1]		
Gas sales volumes		
Residential	41,500	40,169
Commercial	23,736	23,418
Industrial	7,432	6,993
Public authority and other	1,762	1,674
Total gas sales volumes	74,430	72,254
Transportation volumes	39,065	35,124
Total throughput	113,495	107,378
OPERATING REVENUES (000's)[1]		
Gas sales revenues		
Residential	$ 481,673	$ 415,985
Commercial	200,488	172,025
Industrial	30,031	24,758
Public authority and other	12,109	10,533
Total gas sales revenues	724,301	623,301
Transportation revenues	22,481	19,482
Other gas revenues	7,874	6,660
Total operating revenues	$ 754,656	$ 649,443
Average cost of gas per Mcf sold	$ 5.31	$ 4.35

See footnote following these tables.

Pipeline and Storage Operations Sales and Statistical Data

	Three Months Ended December 31	
	2016	**2015**
CUSTOMERS, end of period		
Industrial	90	86
Other	222	262
Total	312	348
INVENTORY STORAGE BALANCE — Bcf	1.7	3.7
PIPELINE TRANSPORTATION VOLUMES — MMcf(1)	186,780	179,852
OPERATING REVENUES (000's)(1)	$ 109,952	$ 98,416

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, 2016. During the three months ended December 31, 2016, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2016 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the first quarter of the fiscal year ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the three months ended December 31, 2016, there were no material changes in the status of the litigation and other matters that were disclosed in Note 11 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. 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/ CHRISTOPHER T. FORSYTHE

Christopher T. Forsythe
Senior Vice President and
Chief Financial Officer
(Duly authorized signatory)

Date: February 7, 2017

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
2.1	Membership Interest Purchase Agreement by and between Atmos Energy Holdings, Inc. as Seller and CenterPoint Energy Services, Inc. as Buyer, dated as of October 29, 2016	Exhibit 2.1 to Form 8-K dated October 29, 2016 (File No. 1-10042)
10	Equity Distribution Agreement, dated as of March 28, 2016, among Atmos Energy Corporation, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC.	Exhibit 1.1 to Form 8-K dated March 28, 2016 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

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

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2017

or

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

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

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

(972) 934-9227

(Registrant's telephone number, including area code)

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

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

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

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐ Emerging growth company ☐

(Do not check if a smaller reporting company)

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

Number of shares outstanding of each of the issuer's classes of common stock, as of April 28, 2017.

Class	Shares Outstanding
No Par Value	105,288,359

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AOCI	Accumulated other comprehensive income
Bcf	Billion cubic feet
FASB	Financial Accounting Standards Board
Fitch	Fitch Ratings, Ltd.
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
PPA	Pension Protection Act of 2006
PRP	Pipeline Replacement Program
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
WNA	Weather Normalization Adjustment

PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2017	September 30, 2016
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 10,725,834	$ 10,142,506
Less accumulated depreciation and amortization	1,987,347	1,873,900
Net property, plant and equipment	8,738,487	8,268,606
Current assets		
Cash and cash equivalents	45,403	47,534
Accounts receivable, net	336,637	215,880
Gas stored underground	120,026	179,070
Current assets of disposal group classified as held for sale	—	151,117
Other current assets	61,018	88,085
Total current assets	563,084	681,686
Goodwill	729,673	726,962
Noncurrent assets of disposal group classified as held for sale	—	28,616
Deferred charges and other assets	330,222	305,019
	$ 10,361,466	$ 10,010,889
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: March 31, 2017 — 105,275,505 shares; September 30, 2016 — 103,930,560 shares	$ 526	$ 520
Additional paid-in capital	2,464,252	2,388,027
Accumulated other comprehensive loss	(86,894)	(188,022)
Retained earnings	1,456,980	1,262,534
Shareholders' equity	3,834,864	3,463,059
Long-term debt	2,314,620	2,188,779
Total capitalization	6,149,484	5,651,838
Current liabilities		
Accounts payable and accrued liabilities	185,212	196,485
Current liabilities of disposal group classified as held for sale	—	72,900
Other current liabilities	390,253	439,085
Short-term debt	670,607	829,811
Current maturities of long-term debt	250,000	250,000
Total current liabilities	1,496,072	1,788,281
Deferred income taxes	1,810,160	1,603,056
Regulatory cost of removal obligation	444,848	424,281
Pension and postretirement liabilities	305,845	297,743
Noncurrent liabilities of disposal group held for sale	—	316
Deferred credits and other liabilities	155,057	245,374
	$ 10,361,466	$ 10,010,889

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended March 31	
	2017	2016
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Distribution segment	$ 962,541	$ 862,127
Pipeline and storage segment	111,972	102,153
Intersegment eliminations	(86,327)	(74,240)
Total operating revenues	988,186	890,040
Purchased gas cost		
Distribution segment	513,096	450,671
Pipeline and storage segment	725	925
Intersegment eliminations	(86,327)	(74,240)
Total purchased gas cost	427,494	377,356
Operation and maintenance expense	132,239	127,857
Depreciation and amortization expense	77,667	71,391
Taxes, other than income	65,614	61,780
Operating income	285,172	251,656
Miscellaneous income (expense)	833	(329)
Interest charges	26,944	27,559
Income from continuing operations before income taxes	259,061	223,768
Income tax expense	97,049	80,765
Income from continuing operations	162,012	143,003
Loss from discontinued operations, net of tax ($0 and ($804))	—	(1,193)
Gain on sale of discontinued operations, net of tax ($10,215 and $0)	2,716	—
Net Income	$ 164,728	$ 141,810
Basic and diluted net income per share		
Income per share from continuing operations	$ 1.52	$ 1.39
Income (loss) per share from discontinued operations	0.03	(0.01)
Net income per share - basic and diluted	$ 1.55	$ 1.38
Cash dividends per share	$ 0.45	$ 0.42
Basic and diluted weighted average shares outstanding	105,935	102,946

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Six Months Ended March 31	
	2017	2016
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Distribution segment	$ 1,717,197	$ 1,511,570
Pipeline and storage segment	221,924	200,569
Intersegment eliminations	(170,767)	(147,346)
Total operating revenues	1,768,354	1,564,793
Purchased gas cost		
Distribution segment	908,442	764,662
Pipeline and storage segment	1,080	366
Intersegment eliminations	(170,723)	(147,346)
Total purchased gas cost	738,799	617,682
Operation and maintenance expense	257,177	247,685
Depreciation and amortization expense	154,625	142,047
Taxes, other than income	122,663	112,994
Operating income	495,090	444,385
Miscellaneous expense	(161)	(1,208)
Interest charges	57,974	57,096
Income from continuing operations before income taxes	436,955	386,081
Income tax expense	160,905	141,532
Income from continuing operations	276,050	244,549
Income from discontinued operations, net of tax ($6,841 and $81)	10,994	122
Gain on sale of discontinued operations, net of tax ($10,215 and $0)	2,716	—
Net Income	$ 289,760	$ 244,671
Basic and diluted net income per share		
Income per share from continuing operations	$ 2.61	$ 2.38
Income per share from discontinued operations	0.13	—
Net income per share - basic and diluted	$ 2.74	$ 2.38
Cash dividends per share	$ 0.90	$ 0.84
Basic and diluted weighted average shares outstanding	105,610	102,837

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
	(Unaudited) (In thousands)			
Net income	$ 164,728	$ 141,810	$ 289,760	$ 244,671
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $879, $(505), $403 and $(947)	1,530	(879)	702	(1,647)
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $2,432, $(30,819), $54,861 and $(28,070)	4,230	(53,618)	95,444	(48,835)
Net unrealized gains on commodity cash flow hedges, net of tax of $0, $140, $3,183 and $1,645	—	220	4,982	2,573
Total other comprehensive income (loss)	5,760	(54,277)	101,128	(47,909)
Total comprehensive income	$ 170,488	$ 87,533	$ 390,888	$ 196,762

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended March 31	
	2017	2016
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 289,760	$ 244,671
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	154,810	143,211
Deferred income taxes	148,657	132,456
Gain on sale of discontinued operations	(12,931)	—
Discontinued cash flow hedging for natural gas marketing commodity contracts	(10,579)	—
Other	10,391	8,771
Net assets / liabilities from risk management activities	26,757	9,528
Net change in operating assets and liabilities	(54,862)	(85,682)
Net cash provided by operating activities	552,003	452,955
Cash Flows From Investing Activities		
Capital expenditures	(559,385)	(536,004)
Acquisition	(85,714)	—
Proceeds from the sale of discontinued operations	133,560	—
Available-for-sale securities activities, net	(8,918)	(2,117)
Other, net	3,787	4,597
Net cash used in investing activities	(516,670)	(533,524)
Cash Flows From Financing Activities		
Net increase (decrease) in short-term debt	(159,204)	169,002
Net proceeds from equity offering	49,400	—
Issuance of common stock through stock purchase and employee retirement plans	16,984	17,641
Proceeds from issuance of long-term debt	125,000	—
Interest rate agreements cash collateral	25,670	—
Cash dividends paid	(95,314)	(86,809)
Net cash provided by (used in) financing activities	(37,464)	99,834
Net increase (decrease) in cash and cash equivalents	(2,131)	19,265
Cash and cash equivalents at beginning of period	47,534	28,653
Cash and cash equivalents at end of period	$ 45,403	$ 47,918

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
March 31, 2017

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") is engaged in the regulated natural gas distribution and pipeline and storage businesses. 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 divisions and subsidiaries operate.

Our distribution business delivers natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six natural gas distribution divisions, which at March 31, 2017, covered service areas located in eight states. In addition, we transport natural gas for others through our distribution system and manage our storage assets located in Kentucky and Tennessee, which are used solely to support our regulated natural gas distribution operations in those states.

Our pipeline and storage business includes the transportation of natural gas to our North Texas and Louisiana distribution systems and the management of our underground storage facilities used to support our North Texas distribution business.

Effective January 1, 2017, we completed the sale of all of the equity interests of Atmos Energy Marketing (AEM) to CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy, Inc. (CES). Accordingly, AEM's historical financial results are reflected in the Company's condensed consolidated financial statements as discontinued operations, which required retrospective application to financial information for all periods presented. Refer to Note 6 for further information. Our discontinued natural gas marketing segment was primarily engaged in a nonregulated natural gas marketing business, conducted by AEM. This business provided natural gas management and transportation services to municipalities, regulated 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, 2016. 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, 2016. Because of seasonal and other factors, the results of operations for the six-month period ended March 31, 2017 are not indicative of our results of operations for the full 2017 fiscal year, which ends September 30, 2017.

We renewed our $25 million unsecured credit facility on April 1, 2017 as discussed in Note 5. In addition, in April 2017, we completed a State of Texas use tax audit that covered the period from October 2011 to June 2015, which resulted in an $18.7 million refund. We are in discussions with the State to update this audit through March 2017. No other 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, 2016.

As discussed in Note 3, due to the realignment of our reportable segments, prior periods' segment information has been recast in accordance with applicable accounting guidance. Additionally, as discussed in Note 6, due to the sale of AEM, prior period amounts have been presented as discontinued operations. The segment realignment and the presentation of discontinued operations do not impact our reported net income, financial position and cash flows.

During the second quarter of fiscal 2017, 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, an entity 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 may need to use more judgment and make more estimates than under current guidance.

The new guidance will become effective for us 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.

As of March 31, 2017, we have substantially completed the evaluation of our sources of revenue and are currently assessing the effect that the new guidance will have on our financial position, results of operations and cash flows. The conclusion of our assessment is contingent, in part, upon the completion of deliberations currently in progress by our industry, notably in connection with efforts to produce an accounting guide intended to be developed by the American Institute of Certified Public Accountants (AICPA).

In association with this undertaking, the AICPA formed a number of industry task forces, including a Power & Utilities (P&U) Task Force. Industry representatives and organizations, the largest auditing firms, the AICPA's Revenue Recognition Working Group and its Financial Reporting Executive Committee have undertaken, and continue to undertake, consideration of several items relevant to our industry as further discussed below. Where applicable or necessary, the FASB's Transition Resource Group (TRG) is also participating.

Currently, the industry is working to address several items including the evaluation of collectability from customers if a utility has regulatory mechanisms to help assure recovery of uncollected accounts from ratepayers and the accounting for funds received from third parties to partially or fully reimburse the cost of construction of an asset. A timeline for the resolution of these deliberations has not been established. Additionally, we are actively working with our peers in the rate-regulated natural gas industry and with the public accounting profession to conclude on the accounting treatment for several other issues that are not expected to be addressed by the P&U Task Force. Based on the apparent progress of these deliberations to date, we currently do not believe the implementation of the new guidance will have a material effect on our financial position, results of operations, cash flows or business processes. We are currently still evaluating the transition method we will utilize to adopt the new guidance as well as the impact to our financial statement presentation and related disclosures.

In May 2015, the FASB issued guidance removing the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. The guidance was effective for us on October 1, 2016 to be applied retrospectively. We measure certain pension plan assets using the net asset value per share practical expedient which are disclosed on an annual basis in our Form 10-K. The adoption of the new standard will have no impact on our results of operations, consolidated balance sheets or cash flows.

In January 2016, the FASB issued guidance related to the classification and measurement of financial instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning October 1, 2018; limited early adoption is permitted. We are currently evaluating the potential impact of this new guidance.

In February 2016, the FASB issued a comprehensive new leasing standard that will require lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The new standard will be effective for us beginning on October 1, 2019; early adoption is permitted. The new leasing standard requires modified retrospective transition, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. We are currently evaluating the effect on our financial position, results of operations and cash flows.

In June 2016, the FASB issued new guidance which will require credit losses on most financial assets measured at amortized cost and certain other instruments to be measured using an expected credit loss model. Under this model, entities will estimate credit losses over the entire contractual term of the instrument from the date of initial recognition of that instrument. In contrast, current U.S. GAAP is based on an incurred loss model that delays recognition of credit losses until it is probable the loss has been incurred. The new guidance also introduces a new impairment recognition model for available-for-sale securities that will require credit losses for available-for-sale debt securities to be recorded through an allowance account. The new standard will be effective for us beginning on October 1, 2021; early adoption is permitted beginning on October 1, 2019. We are currently evaluating the potential impact of this new guidance.

In January 2017, the FASB issued new guidance that simplifies the accounting for goodwill impairments by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the total amount of goodwill allocated to that reporting unit. The new standard will be effective for our fiscal 2021 goodwill impairment test; however, early adoption is permitted for goodwill impairment tests performed on testing dates after January 1, 2017. The adoption of the new standard will have no impact on our results of operations, consolidated balance sheets or cash flows.

In March 2017, the FASB issued new guidance related to the income statement presentation of the components of net periodic benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. The new guidance requires entities to disaggregate the current service cost component of the net benefit cost from the other components and present it with other current compensation costs for related employees in the statement of income. The other components of net benefit cost will be presented outside of income from operations on the statement of income. In addition, only the service cost component of net benefit cost is eligible for capitalization (e.g., as part of inventory or property, plant, and equipment). The new guidance is effective for us in the fiscal year beginning on October 1, 2018 and for interim periods within that year. We are currently evaluating the potential impact of this new guidance.

Regulatory assets and liabilities

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

Significant regulatory assets and liabilities as of March 31, 2017 and September 30, 2016 included the following:

	March 31, 2017	September 30, 2016
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$ 125,547	$ 132,348
Infrastructure mechanisms[2]	61,470	42,719
Deferred gas costs	9,561	45,184
Recoverable loss on reacquired debt	12,482	13,761
Deferred pipeline record collection costs	9,079	7,336
APT annual adjustment mechanism	4,452	7,171
Rate case costs	1,467	1,539
Other	13,264	13,565
	$ 237,322	$ 263,623
Regulatory liabilities:		
Regulatory cost of removal obligations	$ 486,110	$ 476,891
Deferred gas costs	49,672	20,180
Asset retirement obligations	13,404	13,404
Other	10,679	4,250
	$ 559,865	$ 514,725

(1) Includes $11.8 million and $12.4 million of pension and postretirement expense deferred pursuant to regulatory authorization.

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

3. Segment Information

Through November 30, 2016, our consolidated operations were managed and reviewed through three segments:

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

As a result of the sale of Atmos Energy Marketing, we revised the information used by the chief operating decision maker to manage the Company. Accordingly, we have been managing and reviewing our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states and storage assets located in Kentucky and Tennessee, which are used solely to support our natural gas distribution operations in those states. These storage assets were formerly included in our nonregulated segment.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana which were formerly included in our nonregulated segment.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

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 distribution segment operations are geographically dispersed, they are aggregated and reported as a single segment as each natural gas distribution division has similar economic characteristics. In addition, because the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana have similar economic characteristics, they have been aggregated and reported as a single segment.

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, 2016. We evaluate performance based on net income or loss of the respective operating segments. We allocate interest and pension expense to the pipeline and storage segment; however, there is no debt or pension liability recorded on the pipeline and storage segment balance sheet. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Prior periods' segment information has been recast as required by applicable accounting guidance. The segment realignment does not impact our reported consolidated revenues or net income.

Income statements for the three and six months ended March 31, 2017 and 2016 by segment are presented in the following tables:

	Three Months Ended March 31, 2017				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 962,217	$ 25,969	$ —	$ —	$ 988,186
Intersegment revenues	324	86,003	—	(86,327)	—
Total operating revenues	962,541	111,972	—	(86,327)	988,186
Purchased gas cost	513,096	725	—	(86,327)	427,494
Operation and maintenance expense	103,703	28,536	—	—	132,239
Depreciation and amortization expense	61,302	16,365	—	—	77,667
Taxes, other than income	57,636	7,978	—	—	65,614
Operating income	226,804	58,368	—	—	285,172
Miscellaneous income (expense)	1,029	(196)	—	—	833
Interest charges	16,925	10,019	—	—	26,944
Income from continuing operations before income taxes	210,908	48,153	—	—	259,061
Income tax expense	79,763	17,286	—	—	97,049
Income from continuing operations	131,145	30,867	—	—	162,012
Income from discontinued operations, net of tax	—	—	—	—	—
Gain on sale of discontinued operations, net of tax	—	—	2,716	—	2,716
Net income	$ 131,145	$ 30,867	$ 2,716	$ —	$ 164,728
Capital expenditures	$ 208,185	$ 53,238	$ —	$ —	$ 261,423

	Three Months Ended March 31, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 861,756	$ 28,284	$ —	$ —	$ 890,040
Intersegment revenues	371	73,869	—	(74,240)	—
Total operating revenues	862,127	102,153	—	(74,240)	890,040
Purchased gas cost	450,671	925	—	(74,240)	377,356
Operation and maintenance expense	100,146	27,711	—	—	127,857
Depreciation and amortization expense	57,941	13,450	—	—	71,391
Taxes, other than income	54,978	6,802	—	—	61,780
Operating income	198,391	53,265	—	—	251,656
Miscellaneous income (expense)	38	(367)	—	—	(329)
Interest charges	18,414	9,145	—	—	27,559
Income from continuing operations before income taxes	180,015	43,753	—	—	223,768
Income tax expense	64,935	15,830	—	—	80,765
Income from continuing operations	115,080	27,923	—	—	143,003
Loss from discontinued operations, net of tax	—	—	(1,193)	—	(1,193)
Net income (loss)	$ 115,080	$ 27,923	$ (1,193)	$ —	$ 141,810
Capital expenditures	$ 175,186	$ 70,357	$ 49	$ —	$ 245,592

	Six Months Ended March 31, 2017				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,716,483	$ 51,871	$ —	$ —	$ 1,768,354
Intersegment revenues	714	170,053	—	(170,767)	—
Total operating revenues	1,717,197	221,924	—	(170,767)	1,768,354
Purchased gas cost	908,442	1,080	—	(170,723)	738,799
Operation and maintenance expense	196,417	60,804	—	(44)	257,177
Depreciation and amortization expense	122,459	32,166	—	—	154,625
Taxes, other than income	108,182	14,481	—	—	122,663
Operating income	381,697	113,393	—	—	495,090
Miscellaneous income (expense)	396	(557)	—	—	(161)
Interest charges	38,043	19,931	—	—	57,974
Income from continuing operations before income taxes	344,050	92,905	—	—	436,955
Income tax expense	127,541	33,364	—	—	160,905
Income from continuing operations	216,509	59,541	—	—	276,050
Income from discontinued operations, net of tax	—	—	10,994	—	10,994
Gain on sale of discontinued operations, net of tax	—	—	2,716	—	2,716
Net income	$ 216,509	$ 59,541	$ 13,710	$ —	$ 289,760
Capital expenditures	$ 430,669	$ 128,716	$ —	$ —	$ 559,385

	Six Months Ended March 31, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,510,869	$ 53,924	$ —	$ —	$ 1,564,793
Intersegment revenues	701	146,645	—	(147,346)	—
Total operating revenues	1,511,570	200,569	—	(147,346)	1,564,793
Purchased gas cost	764,662	366	—	(147,346)	617,682
Operation and maintenance expense	192,335	55,350	—	—	247,685
Depreciation and amortization expense	115,555	26,492	—	—	142,047
Taxes, other than income	100,536	12,458	—	—	112,994
Operating income	338,482	105,903	—	—	444,385
Miscellaneous expense	(439)	(769)	—	—	(1,208)
Interest charges	38,804	18,292	—	—	57,096
Income from continuing operations before income taxes	299,239	86,842	—	—	386,081
Income tax expense	110,223	31,309	—	—	141,532
Income from continuing operations	189,016	55,533	—	—	244,549
Income from discontinued operations, net of tax	—	—	122	—	122
Net income	$ 189,016	$ 55,533	$ 122	$ —	$ 244,671
Capital expenditures	$ 340,593	$ 195,338	$ 73	$ —	$ 536,004

Balance sheet information at March 31, 2017 and September 30, 2016 by segment is presented in the following tables:

	March 31, 2017				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 6,516,911	$ 2,221,576	$ —	$ —	$ 8,738,487
Investment in subsidiaries	764,702	13,851	—	(778,553)	—
Current assets					
Cash and cash equivalents	45,403	—	—	—	45,403
Other current assets	495,270	24,154	—	(1,743)	517,681
Intercompany receivables	1,015,217	—	—	(1,015,217)	—
Total current assets	1,555,890	24,154	—	(1,016,960)	563,084
Goodwill	586,661	143,012	—	—	729,673
Deferred charges and other assets	302,827	27,395	—	—	330,222
	$ 9,726,991	$ 2,429,988	$ —	$ (1,795,513)	$ 10,361,466
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,834,864	$ 778,553	$ —	$ (778,553)	$ 3,834,864
Long-term debt	2,314,620	—	—	—	2,314,620
Total capitalization	6,149,484	778,553	—	(778,553)	6,149,484
Current liabilities					
Current maturities of long-term debt	250,000	—	—	—	250,000
Short-term debt	670,607	—	—	—	670,607
Other current liabilities	543,577	33,631	—	(1,743)	575,465
Intercompany payables	—	1,015,217	—	(1,015,217)	—
Total current liabilities	1,464,184	1,048,848	—	(1,016,960)	1,496,072
Deferred income taxes	1,230,279	579,881	—	—	1,810,160
Regulatory cost of removal obligation	422,191	22,657	—	—	444,848
Pension and postretirement liabilities	305,845	—	—	—	305,845
Deferred credits and other liabilities	155,008	49	—	—	155,057
	$ 9,726,991	$ 2,429,988	$ —	$ (1,795,513)	$ 10,361,466

	September 30, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 6,208,465	$ 2,060,141	$ —	$ —	$ 8,268,606
Investment in subsidiaries	768,415	13,854	—	(782,269)	—
Current assets					
Cash and cash equivalents	22,117	—	25,417	—	47,534
Current assets of disposal group classified as held for sale	—	—	162,508	(11,391)	151,117
Other current assets	489,963	39,078	5	(46,011)	483,035
Intercompany receivables	971,665	—	—	(971,665)	—
Total current assets	1,483,745	39,078	187,930	(1,029,067)	681,686
Goodwill	583,950	143,012	—	—	726,962
Noncurrent assets of disposal group classified as held for sale	—	—	28,785	(169)	28,616
Deferred charges and other assets	277,240	27,779	—	—	305,019
	$ 9,321,815	$ 2,283,864	$ 216,715	$ (1,811,505)	$ 10,010,889
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,463,059	$ 715,672	$ 66,597	$ (782,269)	$ 3,463,059
Long-term debt	2,188,779	—	—	—	2,188,779
Total capitalization	5,651,838	715,672	66,597	(782,269)	5,651,838
Current liabilities					
Current maturities of long-term debt	250,000	—	—	—	250,000
Short-term debt	829,811	—	35,000	(35,000)	829,811
Current liabilities of the disposal group classified as held for sale	—	—	81,908	(9,008)	72,900
Other current liabilities	605,790	39,911	3,263	(13,394)	635,570
Intercompany payables	—	957,526	14,139	(971,665)	—
Total current liabilities	1,685,601	997,437	134,310	(1,029,067)	1,788,281
Deferred income taxes	1,055,348	543,390	4,318	—	1,603,056
Regulatory cost of removal obligation	397,162	27,119	—	—	424,281
Pension and postretirement liabilities	297,743	—	—	—	297,743
Noncurrent liabilities of disposal group classified as held for sale	—	—	316	—	316
Deferred credits and other liabilities	234,123	246	11,174	(169)	245,374
	$ 9,321,815	$ 2,283,864	$ 216,715	$ (1,811,505)	$ 10,010,889

4. Earnings Per Share

We use the two-class method of computing earnings per share because we have participating securities in the form of non-vested restricted stock units with a nonforfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator. Basic and diluted earnings per share for the three and six months ended March 31, 2017 and 2016 are calculated as follows:

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
	(In thousands, except per share amounts)			
Basic and Diluted Earnings Per Share from continuing operations				
Income from continuing operations	$ 162,012	$ 143,003	$ 276,050	$ 244,549
Less: Income from continuing operations allocated to participating securities	193	231	348	405
Income from continuing operations available to common shareholders	$ 161,819	$ 142,772	$ 275,702	$ 244,144
Basic and diluted weighted average shares outstanding	105,935	102,946	105,610	102,837
Income from continuing operations per share — Basic and Diluted	$ 1.52	$ 1.39	$ 2.61	$ 2.38
Basic and Diluted Earnings Per Share from discontinued operations				
Income (loss) from discontinued operations	$ 2,716	$ (1,193)	$ 13,710	$ 122
Less: Income from discontinued operations allocated to participating securities	2	—	15	—
Income (loss) from discontinued operations available to common shareholders	$ 2,714	$ (1,193)	$ 13,695	$ 122
Basic and diluted weighted average shares outstanding	105,935	102,946	105,610	102,837
Income (loss) from discontinued operations per share — Basic and Diluted	$ 0.03	$ (0.01)	$ 0.13	$ —
Net income per share — Basic and Diluted	$ 1.55	$ 1.38	$ 2.74	$ 2.38

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, 2016. Except as noted below, there were no material changes in the terms of our debt instruments during the six months ended March 31, 2017.

Long-term debt at March 31, 2017 and September 30, 2016 consisted of the following:

	March 31, 2017	September 30, 2016
	(In thousands)	
Unsecured 6.35% Senior Notes, due June 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	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
Floating-rate term loan, due 2019	125,000	—
Total long-term debt	2,585,000	2,460,000
Less:		
Original issue discount on unsecured senior notes and debentures	4,099	4,270
Debt issuance cost	16,281	16,951
Current maturities	250,000	250,000
	$ 2,314,620	$ 2,188,779

On September 22, 2016, we entered into a three year, $200 million multi-draw floating-rate term loan agreement with a syndicate of three lenders. Borrowings under the term loan may be made in increments of $1.0 million or higher, may be repaid at any time during the loan period and will bear interest at a rate dependent upon our credit ratings at the time of such borrowing and based, at our election, on a base rate or LIBOR for the applicable interest period. The term loan will be used to refinance existing indebtedness and for working capital, capital expenditures and other general corporate purposes. At March 31, 2017, there was $125.0 million outstanding under the term loan.

We utilize short-term debt 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 $1.5 billion commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $1.5 billion of total working capital funding. The primary source of our funding is our commercial paper program, which is supported by a five-year unsecured $1.5 billion credit facility that expires September 25, 2021. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 1.25 percent, based on the Company's credit ratings. Additionally, the facility contains a $250 million accordion feature, which provides the opportunity to increase the total committed loan to $1.75 billion. This facility was amended in October 2016 to increase the total availability from $1.25 billion. At March 31, 2017 and September 30, 2016 a total of $670.6 million and $829.8 million was outstanding under our commercial paper program.

Additionally, we have a $25 million unsecured facility, which was renewed on April 1, 2017, and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. At March 31, 2017, there were no borrowings outstanding under either of these facilities; however, outstanding letters of credit reduced the total amount available to us under our $10 million unsecured revolving facility to $4.1 million.

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At March 31, 2017, 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.

These credit facilities and our public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers. Additionally, our public debt indentures relating to our senior notes and debentures, as well as certain of our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. We were in compliance with all of our debt covenants as of March 31, 2017. 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.

AEM had one uncommitted $25 million 364-day bilateral credit facility that was scheduled to expire on July 31, 2017 and one committed $15 million 364-day bilateral credit facility that was scheduled to expire on September 30, 2017. In connection with the sale of AEM discussed in Note 6, both facilities were terminated on January 3, 2017.

6. Divestitures and Acquisitions

Divestiture of Atmos Energy Marketing (AEM)

On October 29, 2016, we entered into a Membership Interest Purchase Agreement (the Agreement) with CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy, Inc. (CES) to sell all of the equity interests of AEM. The transaction closed on January 3, 2017, with an effective date of January 1, 2017. CES paid a cash purchase price of $38.3 million plus estimated working capital of $103.2 million for total cash consideration of $141.5 million. Of this amount, $7.0 million was placed into escrow and will be paid to the Company within 24 months, net of any indemnification claims agreed upon between the two companies. We recognized a net gain of $0.03 per diluted share on the sale in the second quarter of fiscal 2017 and expect to complete the working capital true–up during the third quarter of fiscal 2017.

The operating results of our natural gas marketing reportable segment have been reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Accordingly, expenses related to allocable general corporate overhead and interest expense are not included in these results. The decision to report this segment as a discontinued operation was predicated, in part, on the following qualitative and quantitative factors: 1) the disposal results in the company becoming a fully regulated entity; 2) the fact that an entire reportable segment will be disposed and 3) the fact the disposed segment represented in excess of 30 percent of consolidated revenues over the last five fiscal years.

The tables below set forth selected financial and operational information related to assets, liabilities and operating results related to discontinued operations. Operating expenses include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income. Additionally, assets and liabilities related to our natural gas marketing operations are classified as "held for sale" on our consolidated balance sheet at September 30, 2016. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported consolidated net income.

The following tables present statement of income data related to discontinued operations.

	Three Months Ended March 31	
	2017	2016
	(In thousands)	
Operating revenues	$ —	$ 269,519
Purchased gas cost	—	264,259
Operating expenses	—	6,900
Operating loss	—	(1,640)
Other nonoperating expense	—	(357)
Loss from discontinued operations before income taxes	—	(1,997)
Income tax benefit	—	(804)
Loss from discontinued operations	—	(1,193)
Gain on sale from discontinued operations, net of tax ($10,215 and $0)	2,716	—
Net income (loss) from discontinued operations	$ 2,716	$ (1,193)

	Six Months Ended March 31	
	2017	2016
	(In thousands)	
Operating revenues	$ 303,474	$ 528,776
Purchased gas cost	277,554	514,047
Operating expenses	7,874	12,893
Operating income	18,046	1,836
Other nonoperating expense	(211)	(1,633)
Income from discontinued operations before income taxes	17,835	203
Income tax expense	6,841	81
Income from discontinued operations	10,994	122
Gain on sale from discontinued operations, net of tax ($10,215 and $0)	2,716	—
Net income from discontinued operations	$ 13,710	$ 122

The following table presents a reconciliation of the carrying amounts of major classes of assets and liabilities of our natural gas marketing's operations to total assets and liabilities classified as held for sale.

	March 31, 2017	September 30, 2016
	(In thousands)	
Assets:		
Net property, plant and equipment	$ —	$ 11,905
Accounts receivable	—	93,551
Gas stored underground	—	54,246
Other current assets	—	14,711
Goodwill	—	16,445
Deferred charges and other assets	—	435
Total assets of the disposal group classified as held for sale in the statement of financial position [(1)]	—	191,293
Cash	—	25,417
Other assets	—	5
Total assets of disposal group in the statement of financial position	$ —	$ 216,715
Liabilities:		
Accounts payable and accrued liabilities	$ —	$ 72,268
Other current liabilities	—	9,640
Deferred credits and other	—	316
Total liabilities of the disposal group classified as held for sale in the statement of financial position [(1)]	—	82,224
Intercompany note payable	—	35,000
Tax liabilities	—	15,471
Intercompany payables	—	14,139
Other liabilities	—	3,284
Total liabilities of disposal group in the statement of financial position	$ —	$ 150,118

(1) Amounts in the comparative period are classified as current and long term in the statement of financial position.

The following table presents statement of cash flow data related to discontinued operations.

	Six Months Ended March 31	
	2017	2016
	(In thousands)	
Depreciation and amortization expense	$ 185	$ 1,164
Capital expenditures	$ —	$ 73
Noncash gain (loss) in commodity contract cash flow hedges	$ 18,744	$ (4,218)

Acquisition of EnLink Pipeline

On December 20, 2016, we executed a purchase and sale agreement to acquire the general partnership and limited partnership interests in EnLink North Texas Pipeline, LP (EnLink Pipeline) from EnLink Energy GP, LLC and EnLink Midstream Operating, LP for an all–cash price of $85 million, plus estimated working capital. After considering estimated working capital, the total proceeds paid were $85.7 million. The final purchase price is subject to adjustment after the estimated working capital is finalized during the third quarter of fiscal 2017.

EnLink Pipeline's primary asset is a 140–mile natural gas pipeline located on the north side of the Dallas–Fort Worth Metroplex. As of March 31, 2017, the $85 million purchase price has been allocated, based on fair value using observable market inputs, to the net book value of the acquired pipeline. The final purchase price allocation is subject to adjustment pending the completion of our analysis of the fair value of certain contracts included in the acquisition, which we expect to finalize in the third quarter of fiscal 2017.

7. Shareholders' Equity

Shelf Registration and At-the-Market Equity Sales Program

On March 28, 2016, we filed a registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue, from time to time, up to $2.5 billion in common stock and/or debt securities. We also filed a prospectus supplement under the registration statement relating to an at-the-market (ATM) equity distribution program under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. During the first fiscal quarter of 2017, we sold 690,812 shares of common stock under our existing ATM program for $50.0 million and received net proceeds of $49.4 million. At March 31, 2017, approximately $2.4 billion of securities remain available for issuance under the shelf registration statement and approximately $50.0 million of equity remained available for issuance under the ATM program.

Accumulated Other Comprehensive Income (Loss)

We record deferred gains (losses) in AOCI related to available-for-sale securities, interest rate 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 (loss).

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
		(In thousands)		
September 30, 2016	$ 4,484	$ (187,524)	$ (4,982)	$ (188,022)
Other comprehensive income before reclassifications	634	95,271	9,847	105,752
Amounts reclassified from accumulated other comprehensive income	68	173	(4,865)	(4,624)
Net current-period other comprehensive income	702	95,444	4,982	101,128
March 31, 2017	$ 5,186	$ (92,080)	$ —	$ (86,894)

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
		(In thousands)		
September 30, 2015	$ 4,949	$ (88,842)	$ (25,437)	$ (109,330)
Other comprehensive loss before reclassifications	(1,568)	(49,008)	(19,185)	(69,761)
Amounts reclassified from accumulated other comprehensive income	(79)	173	21,758	21,852
Net current-period other comprehensive income (loss)	(1,647)	(48,835)	2,573	(47,909)
March 31, 2016	$ 3,302	$ (137,677)	$ (22,864)	$ (157,239)

The following tables detail reclassifications out of AOCI for the three and six months ended March 31, 2017 and 2016. Amounts in parentheses below indicate decreases to net income in the statement of income.

	Three Months Ended March 31, 2017		
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**		**Affected Line Item in the Statement of Income**
	(In thousands)		
Available-for-sale securities	$	(107)	Operation and maintenance expense
		(107)	Total before tax
		39	Tax benefit
	$	(68)	Net of tax
Cash flow hedges			
Interest rate agreements	$	(136)	Interest charges
Commodity contracts		—	Purchased gas cost
		(136)	Total before tax
		50	Tax benefit
	$	(86)	Net of tax
Total reclassifications	$	(154)	Net of tax

	Three Months Ended March 31, 2016		
Accumulated Other Comprehensive Income Components	**Amount Reclassified from Accumulated Other Comprehensive Income**		**Affected Line Item in the Statement of Income**
	(In thousands)		
Available-for-sale securities	$	124	Operation and maintenance expense
		124	Total before tax
		(45)	Tax expense
	$	79	Net of tax
Cash flow hedges			
Interest rate agreements	$	(136)	Interest charges
Commodity contracts		(12,703)	Purchased gas cost(1)
		(12,839)	Total before tax
		5,004	Tax benefit
	$	(7,835)	Net of tax
Total reclassifications	$	(7,756)	Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2017 — Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$ (107)	Operation and maintenance expense
	(107)	Total before tax
	39	Tax benefit
	$ (68)	Net of tax
Cash flow hedges		
Interest rate agreements	$ (273)	Interest charges
Commodity contracts	7,976	Purchased gas cost(1)
	7,703	Total before tax
	(3,011)	Tax expense
	$ 4,692	Net of tax
Total reclassifications	$ 4,624	Net of tax

Accumulated Other Comprehensive Income Components	Six Months Ended March 31, 2016 — Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$ 124	Operation and maintenance expense
	124	Total before tax
	(45)	Tax expense
	$ 79	Net of tax
Cash flow hedges		
Interest rate agreements	$ (273)	Interest charges
Commodity contracts	(35,668)	Purchased gas cost(1)
	(35,941)	Total before tax
	14,010	Tax benefit
	$ (21,931)	Net of tax
Total reclassifications	$ (21,852)	Net of tax

(1) Amounts are presented as part of income from discontinued operations on the condensed consolidated statements of income.

8. Interim Pension and Other Postretirement Benefit Plan Information

The components of our net periodic pension cost for our pension and other postretirement benefit plans for the three and six months ended March 31, 2017 and 2016 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.

	Three Months Ended March 31			
	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 5,217	$ 4,697	$ 3,109	$ 2,706
Interest cost	6,297	7,094	2,670	3,106
Expected return on assets	(6,994)	(6,880)	(1,797)	(1,566)
Amortization of transition obligation	—	—	—	20
Amortization of prior service credit	(58)	(56)	(411)	(411)
Amortization of actuarial (gain) loss	4,249	3,320	(707)	(542)
Net periodic pension cost	$ 8,711	$ 8,175	$ 2,864	$ 3,313

	Six Months Ended March 31			
	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 10,433	$ 9,395	$ 6,218	$ 5,412
Interest cost	12,594	14,189	5,340	6,212
Expected return on assets	(13,988)	(13,761)	(3,593)	(3,132)
Amortization of transition obligation	—	—	—	41
Amortization of prior service credit	(116)	(113)	(822)	(822)
Amortization of actuarial (gain) loss	8,498	6,640	(1,414)	(1,084)
Net periodic pension cost	$ 17,421	$ 16,350	$ 5,729	$ 6,627

The assumptions used to develop our net periodic pension cost for the three and six months ended March 31, 2017 and 2016 are as follows:

	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
Discount rate	3.73%	4.55%	3.73%	4.55%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.00%	7.00%	4.45%	4.45%

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 plan as of January 1, 2017. Based on that determination, we are not required to make a minimum contribution to our defined benefit plan during fiscal 2017; however, we may consider whether a voluntary contribution is prudent to maintain certain funding levels.

We contributed $6.6 million to our other post-retirement benefit plans during the six months ended March 31, 2017. We expect to contribute a total of between $10 million and $20 million to these plans during fiscal 2017.

9. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 11 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016, there were no material changes in the status of such litigation and environmental-related matters or claims during the six months ended March 31, 2017.

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 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. These purchase commitment contracts are detailed in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. There were no material changes to the purchase commitments for the six months ended March 31, 2017.

Regulatory Matters

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

As of March 31, 2017, formula rate mechanisms were in progress in our Louisiana, Tennessee and Mid-Tex service areas and infrastructure mechanisms were in progress in our Mid-Tex, Mississippi and West Texas service areas. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments.*

10. Financial Instruments

We currently use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments and the related accounting for these financial instruments are fully described in Notes 2 and 13 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. During the six months ended March 31, 2017, except for the change in the scope of our natural gas marketing commodity risk management activities as a result of the sale of AEM, there were no material 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 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 2016-2017 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 27 percent, or 16.2 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Natural Gas Marketing Commodity Risk Management Activities

Our natural gas marketing segment was 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. Through December 31, 2016, we managed 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. Effective January 1, 2017, as a result of the sale of AEM, these activities were discontinued.

Due to the anticipated sale of AEM, we determined that the cash flows associated with our natural gas marketing commodity cash flow hedges were no longer probable of occurring; therefore, we discontinued hedge accounting as of December 31, 2016. As a result, we reclassified the gain in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of purchased gas costs and recognized a pre-tax gain of $10.6 million, which is included in income from discontinued operations on the condensed consolidated statement of income for the three months ended December 31, 2016.

Interest Rate Risk Management Activities

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

As of March 31, 2017, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $250 million and $450 million unsecured senior notes in fiscal 2017 and fiscal 2019, at 3.37% and 3.78%, which we designated as cash flow hedges at the time the swaps were executed. As of March 31, 2017, we had $18.1 million of net realized losses in accumulated other comprehensive income (AOCI) associated with the settlement of financial instruments used to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes, which will be recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for these settled amounts extend through fiscal 2045.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our condensed consolidated balance sheet and income statements.

As of March 31, 2017, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of March 31, 2017, we had 8,909 MMcf of net short commodity contracts outstanding. These contracts have not been designated as hedges.

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments as of March 31, 2017 and September 30, 2016. 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	Assets	Liabilities
		(In thousands)	
March 31, 2017			
Designated As Hedges:			
Interest rate contracts	Other current liabilities	$ —	$ (22,199)
Interest rate contracts	Deferred credits and other liabilities	—	(94,256)
Total		—	(116,455)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	3,096	(645)
Total		3,096	(645)
Gross Financial Instruments		3,096	(117,100)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		—	—
Net Financial Instruments		3,096	(117,100)
Cash collateral		—	—
Net Assets/Liabilities from Risk Management Activities		$ 3,096	$ (117,100)

	Balance Sheet Location	Assets	Liabilities
		(In thousands)	
September 30, 2016			
Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	$ 6,612	$ (21,903)
Interest rate contracts	Other current assets / Other current liabilities	—	(68,481)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	2,178	(3,779)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(198,008)
Total		8,790	(292,171)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	21,186	(18,812)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	14,165	(12,701)
Total		35,351	(31,513)
Gross Financial Instruments		44,141	(323,684)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		(39,290)	39,290
Net Financial Instruments		4,851	(284,394)
Cash collateral		6,775	43,575
Net Assets/Liabilities from Risk Management Activities		$ 11,626	$ (240,819)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our natural gas marketing segment was recorded as a component of purchased gas cost, which is included in discontinued operations on the condensed consolidated statements of income, and primarily results from differences in the location and timing of the derivative instrument and the hedged item. For the three months ended March 31, 2016, we recognized a loss arising from fair value and cash flow hedge ineffectiveness of $3.3 million. For the six months ended March 31, 2017 and 2016, we recognized gains arising from fair value and cash flow hedge ineffectiveness of $3.4 million and $4.6 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our natural gas marketing segment commodity contracts designated as fair value hedges and the related hedged item on the results of discontinued operations on our condensed consolidated income statement for the three and six months ended March 31, 2017 and 2016 is presented below.

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
	(In thousands)			
Commodity contracts	$ —	$ 4,594	$ (9,567)	$ 10,338
Fair value adjustment for natural gas inventory designated as the hedged item	—	(7,939)	12,858	(5,778)
Total (increase) decrease in purchased gas cost reflected in income from discontinued operations	$ —	$ (3,345)	$ 3,291	$ 4,560
The (increase) decrease in purchased gas cost reflected in income from discontinued operations is comprised of the following:				
Basis ineffectiveness	$ —	$ (2,095)	$ (597)	$ (806)
Timing ineffectiveness	—	(1,250)	3,888	5,366
	$ —	$ (3,345)	$ 3,291	$ 4,560

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.

Cash Flow Hedges

The impact of our interest rate and natural gas marketing segment cash flow hedges on our condensed consolidated income statements for the three and six months ended March 31, 2017 and 2016 is presented below.

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
	(In thousands)			
Loss reclassified from AOCI for effective portion of natural gas marketing commodity contracts	$ —	$ (12,703)	$ (2,612)	$ (35,668)
Gain arising from ineffective portion of natural gas marketing commodity contracts	—	61	111	18
Gain on discontinuance of cash flow hedging of natural gas marketing commodity contracts reclassified from AOCI	—	—	10,579	—
Total impact on purchased gas cost reflected in income from discontinued operations	—	(12,642)	8,078	(35,650)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(136)	(136)	(273)	(273)
Total Impact from Cash Flow Hedges	$ (136)	$ (12,778)	$ 7,805	$ (35,923)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the three and six months ended March 31, 2017 and 2016. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$ 4,144	$ (53,704)	$ 95,271	$ (49,008)
Forward commodity contracts	—	(7,529)	9,847	(19,185)
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	86	86	173	173
Forward commodity contracts	—	7,749	(4,865)	21,758
Total other comprehensive income (loss) from hedging, net of tax(1)	$ 4,230	$ (53,398)	$ 100,426	$ (46,262)

(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 natural gas marketing segment commodity contracts were recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of March 31, 2017. 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
	(In thousands)
Next twelve months	$ (598)
Thereafter	(17,532)
Total(1)	$ (18,130)

(1) Utilizing an income tax rate of 37 percent.

Financial Instruments Not Designated as Hedges

The impact of the natural gas marketing segment's financial instruments that have not been designated as hedges on our condensed consolidated income statements for the three months ended March 31, 2016 was an increase in purchased gas cost of $2.5 million, which is included in discontinued operations on the condensed consolidated statements of income. For the six months ended March 31, 2017 and 2016 purchased gas cost (increased) decreased by $6.8 million and $(4.7) million.

As discussed above, financial instruments used in our distribution segment are not designated as hedges. However, there is no earnings impact on our 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.

11. 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, 2016. During the six months ended March 31, 2017, 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 7 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2016.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3). The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2017 and September 30, 2016. 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	March 31, 2017
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 3,096	$ —	$ —	$ 3,096
Available-for-sale securities					
Registered investment companies	37,995	—	—	—	37,995
Bond mutual funds	10,438	—	—	—	10,438
Bonds	—	30,596	—	—	30,596
Money market funds	—	3,623	—	—	3,623
Total available-for-sale securities	48,433	34,219	—	—	82,652
Total assets	$ 48,433	$ 37,315	$ —	$ —	$ 85,748
Liabilities:					
Financial instruments	$ —	$ 117,100	$ —	$ —	$ 117,100

	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)	September 30, 2016
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 44,141	$ —	$ (32,515)	$ 11,626
Hedged portion of gas stored underground	52,578	—	—	—	52,578
Available-for-sale securities					
Registered investment companies	38,677	—	—	—	38,677
Bonds	—	31,394	—	—	31,394
Money market funds	—	2,630	—	—	2,630
Total available-for-sale securities	38,677	34,024	—	—	72,701
Total assets	$ 91,255	$ 78,165	$ —	$ (32,515)	$ 136,905
Liabilities:					
Financial instruments	$ —	$ 323,684	$ —	$ (82,865)	$ 240,819

(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. As of September 30, 2016, we had $50.4 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $43.6 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $6.8 million is classified as current risk management assets.

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

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
	(In thousands)			
As of March 31, 2017				
Domestic equity mutual funds	$ 25,158	$ 6,956	$ (101)	$ 32,013
Foreign equity mutual funds	4,581	1,401	—	5,982
Bond mutual funds	10,469	—	(31)	10,438
Bonds	30,588	43	(35)	30,596
Money market funds	3,623	—	—	3,623
	$ 74,419	$ 8,400	$ (167)	$ 82,652
As of September 30, 2016				
Domestic equity mutual funds	$ 26,692	$ 6,419	$ (590)	$ 32,521
Foreign equity mutual funds	4,954	1,202	—	6,156
Bonds	31,296	108	(10)	31,394
Money market funds	2,630	—	—	2,630
	$ 65,572	$ 7,729	$ (600)	$ 72,701

At March 31, 2017 and September 30, 2016, our available-for-sale securities included $41.6 million and $41.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At March 31, 2017, we maintained investments in bonds that have contractual maturity dates ranging from April 2017 through September 2020.

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

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of March 31, 2017 and September 30, 2016:

	March 31, 2017	September 30, 2016
	(In thousands)	
Carrying Amount	$ 2,585,000	$ 2,460,000
Fair Value	$ 2,806,986	$ 2,844,990

12. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 16 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. Except for the sale of AEM, during the six months ended March 31, 2017, there were no material changes in our concentration of credit risk.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have reviewed the condensed consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of March 31, 2017 and the related condensed consolidated statements of income and comprehensive income for the three and six-month periods ended March 31, 2017 and 2016 and the condensed consolidated statements of cash flows for the six-month periods ended March 31, 2017 and 2016. 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, 2016, 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 14, 2016 except for the effects of the change in segments described in Note 3 and the discontinued operations described in Note 15, to which the date is April 12, 2017, 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, 2016, is fairly stated, in all material respects, in relation to the consolidated balance sheets from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
May 4, 2017

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, 2016.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit and capital 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 commodity price volatility, counterparty creditworthiness or performance and interest rate risk; 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 natural gas distribution business; increased costs of providing health care benefits along with pension and postretirement health care benefits and increased funding requirements; the inability to continue to hire, train and retain appropriate personnel; 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 climate changes or related additional legislation or regulation in the future; the inherent hazards and risks involved in operating our distribution and pipeline and storage businesses; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses, as well as our natural gas marketing business through December 31, 2016. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six distribution divisions, which at March 31, 2017 covered service areas located in eight states. In addition, we transport natural gas for others through our distribution and pipeline systems.

Through December 31, 2016, our natural gas marketing business provided natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast. We completed the sale of this business in January 2017.

We manage and review our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states, and storage assets located in Kentucky and Tennessee, which are used solely to support our natural gas distribution operations in those states. These storage assets were formerly included in our nonregulated segment.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Energy Pipeline-Texas division and our natural gas transmission operations in Louisiana which were included in our former nonregulated segment.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

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, 2016 and include the following:

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

Our critical accounting policies are reviewed periodically by the Audit Committee of our Board of Directors. There were no significant changes to these critical accounting policies during the six months ended March 31, 2017.

RESULTS OF OPERATIONS

Executive Summary

Atmos Energy strives to operate its businesses safely and reliably while delivering superior shareholder value. In recent years, we have implemented rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved rate from customer usage patterns. Additionally, we have significantly increased investments in the safety and reliability of our natural gas distribution and transmission infrastructure. This increased level of investment and timely recovery of these investments through our regulatory mechanisms has resulted in increased earnings and operating cash flows in recent years.

The pursuit of our strategy was the primary driver for our decision to sell our nonregulated natural gas marketing business and to fully exit that business. The sale was announced in October 2016 and closed in January 2017 with the receipt of $133.6 million in cash proceeds, including estimated working capital. We recorded a net gain of $0.03 per diluted share on the sale in the second quarter of fiscal 2017. The proceeds received from the transaction will be used to fund infrastructure in our remaining businesses. As a result of the sale, the results of operations for the divested business have been presented as discontinued operations.

	Three Months Ended March 31		
	2017	2016	Change
	(In thousands, except per share data)		
Distribution operations	$ 131,145	$ 115,080	$ 16,065
Pipeline and storage operations	30,867	27,923	2,944
Net income from continuing operations	162,012	143,003	19,009
Net income (loss) from discontinued operations	2,716	(1,193)	3,909
Net income	$ 164,728	$ 141,810	$ 22,918
Diluted EPS from continuing operations	$ 1.52	$ 1.39	$ 0.13
Diluted EPS from discontinued operations	0.03	(0.01)	0.04
Consolidated diluted EPS	$ 1.55	$ 1.38	$ 0.17

	Six Months Ended March 31		
	2017	2016	Change
	(In thousands, except per share data)		
Distribution operations	$ 216,509	$ 189,016	$ 27,493
Pipeline and storage operations	59,541	55,533	4,008
Net income from continuing operations	276,050	244,549	31,501
Net income from discontinued operations	13,710	122	13,588
Net income	$ 289,760	$ 244,671	$ 45,089
Diluted EPS from continuing operations	$ 2.61	$ 2.38	$ 0.23
Diluted EPS from discontinued operations	0.13	—	0.13
Consolidated diluted EPS	$ 2.74	$ 2.38	$ 0.36

Net income from continuing operations increased 13 percent, compared to the prior-year period, despite weather that was 29 percent warmer than normal and 12 percent warmer than the prior-year period, primarily due to positive rate outcomes and customer growth in our distribution business. During the six months ended March 31, 2017, our distribution segment completed 11 regulatory proceedings, resulting in an increase in annual operating income of $25.4 million and had nine ratemaking efforts in progress at March 31, 2017 seeking $80.8 million of additional annual operating income. Additionally, on January 6, 2017, our Atmos Pipeline - Texas Division filed its statement of intent seeking $55.2 million in additional annual operating income. Our discontinued natural gas marketing results for the six months ended March 31, 2017 primarily include a pre-tax gain of $10.6 million recognized in the first fiscal quarter related to the discontinuance of cash flow hedging for our natural gas marketing commodity contracts and a $2.7 million net gain on sale recognized in January 2017 upon completion of the sale.

Capital expenditures for the first six months of fiscal 2017 were $559.4 million. Approximately 77 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 $1.1 billion and $1.25 billion for fiscal 2017. We funded our capital expenditure program primarily through operating cash flows of $552.0 million, $125 million in borrowings under our three-year $200 million multi-draw term loan, $49.4 million in proceeds from the issuance of common stock under our at-the-market equity distribution program and net short-term debt borrowings. In addition, we acquired EnLink Pipeline in the first fiscal quarter of 2017 for an all–cash price of $85.0 million, plus estimated working capital. The acquisition of EnLink Pipeline increases the capacity on our APT intrastate pipeline to serve transportation customers in North Texas, which continues to experience significant population growth.

As a result of our sustained financial performance, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 7.1 percent for fiscal 2017.

Distribution Segment

The distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states, and storage assets located in Kentucky and Tennessee, which are solely used to support our regulated natural gas distribution operations in those states. These storage assets were previously included in our former nonregulated segment. The primary factors that impact the results of this segment 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 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 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, which is defined as operating revenues less purchased gas cost, is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas includes franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the associated tax expense as a component of taxes, other than income. Although changes in these revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

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

Three Months Ended March 31, 2017 compared with Three Months Ended March 31, 2016

Financial and operational highlights for our distribution segment for the three months ended March 31, 2017 and 2016 are presented below.

	Three Months Ended March 31		
	2017	**2016**	**Change**
	(In thousands, unless otherwise noted)		
Gross profit	$ 449,445	$ 411,456	$ 37,989
Operating expenses	222,641	213,065	9,576
Operating income	226,804	198,391	28,413
Miscellaneous income	1,029	38	991
Interest charges	16,925	18,414	(1,489)
Income before income taxes	210,908	180,015	30,893
Income tax expense	79,763	64,935	14,828
Net income	$ 131,145	$ 115,080	$ 16,065
Consolidated distribution sales volumes — MMcf	97,754	116,370	(18,616)
Consolidated distribution transportation volumes — MMcf	39,915	40,677	(762)
Total consolidated distribution throughput — MMcf	137,669	157,047	(19,378)
Consolidated distribution average cost of gas per Mcf sold	$ 5.25	$ 3.87	$ 1.38

Income for our distribution segment increased 14 percent, primarily due to a $38.0 million increase in gross profit, which is defined as operating revenues less purchased gas cost, partially offset with a $9.6 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $29.5 million net increase in rate adjustments, primarily in our Mid-Tex, Louisiana and Mississippi Divisions.
- Customer growth, primarily in our Mid-Tex and Tennessee service areas, which contributed an incremental net $2.5 million.
- a $0.6 million net decrease in consumption, primarily due to weather that was 34 percent warmer than normal and 23 percent warmer than the prior-year quarter.

The increase in operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to higher levels of employee-related costs and line locate activities, primarily in our Mid-Tex Division, and higher depreciation and property tax expense associated with increased capital investments, partially offset by lower legal expenses.

The following table shows our operating income by distribution division, in order of total rate base, for the three months ended March 31, 2017 and 2016. The presentation of our distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended March 31		
	2017	2016	Change
	(In thousands)		
Mid-Tex	$ 90,809	$ 80,377	$ 10,432
Kentucky/Mid-States	34,010	30,647	3,363
Louisiana	30,362	24,860	5,502
West Texas	21,023	20,245	778
Mississippi	25,802	23,661	2,141
Colorado-Kansas	18,331	17,986	345
Other	6,467	615	5,852
Total	$ 226,804	$ 198,391	$ 28,413

Six Months Ended March 31, 2017 compared with Six Months Ended March 31, 2016

Financial and operational highlights for our distribution segment for the six months ended March 31, 2017 and 2016 are presented below.

	Six Months Ended March 31		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 808,755	$ 746,908	$ 61,847
Operating expenses	427,058	408,426	18,632
Operating income	381,697	338,482	43,215
Miscellaneous income (expense)	396	(439)	835
Interest charges	38,043	38,804	(761)
Income before income taxes	344,050	299,239	44,811
Income tax expense	127,541	110,223	17,318
Net income	$ 216,509	$ 189,016	$ 27,493
Consolidated regulated distribution sales volumes — MMcf	172,184	188,624	(16,440)
Consolidated regulated distribution transportation volumes — MMcf	76,090	72,888	3,202
Total consolidated regulated distribution throughput — MMcf	248,274	261,512	(13,238)
Consolidated regulated distribution average cost of gas per Mcf sold	$ 5.28	$ 4.05	$ 1.23

Income for our distribution segment increased 15 percent, primarily due to a $61.8 million increase in gross profit, which is defined as operating revenues less purchased gas cost, partially offset with an $18.6 million increase in operating expenses. The year-over-year increase in gross profit primarily reflects:

- a $46.6 million net increase in rate adjustments, primarily in our Mid-Tex, Louisiana and Mississippi Divisions.
- Customer growth, primarily in our Mid-Tex and Tennessee service areas, which contributed an incremental $4.2 million.
- a $3.8 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $2.0 million increase in the related tax expense.
- a $2.7 million increase in transportation primarily in our West Texas and Kentucky/Mid-States Divisions.
- a $1.0 million net decrease in consumption due to warmer weather compared to the prior-year period.

The increase in operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to an increase in employee-related costs, higher levels of line locate and pipeline integrity activities, primarily in our Mid-Tex Division, and higher depreciation and property tax expense associated with increased capital investments.

Net income for the prior-year period includes a $3.3 million income tax benefit for stock awards that vested during fiscal 2016 as a result of adopting new stock-based accounting guidance in the prior year.

The following table shows our operating income by distribution division, in order of total rate base, for the six months ended March 31, 2017 and 2016. The presentation of our distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Six Months Ended March 31		
	2017	2016	Change
		(In thousands)	
Mid-Tex	$ 163,552	$ 148,296	$ 15,256
Kentucky/Mid-States	56,748	49,785	6,963
Louisiana	50,225	40,703	9,522
West Texas	35,951	33,134	2,817
Mississippi	37,760	36,453	1,307
Colorado-Kansas	30,036	28,078	1,958
Other	7,425	2,033	5,392
Total	$ 381,697	$ 338,482	$ 43,215

Recent Ratemaking Developments

The amounts described in the following sections represent the operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of a commission's or other governmental authority's final ruling. During the first six months of fiscal 2017, we completed 11 regulatory proceedings, resulting in a $25.4 million increase in annual operating income as summarized below:

Rate Action	Annual Increase in Operating Income
	(In thousands)
Annual formula rate mechanisms	$ 24,637
Rate case filings	6
Other rate activity	784
	$ 25,427

Additionally, the following ratemaking efforts seeking $80.8 million in annual operating income were in progress as of March 31, 2017:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	Formula Rate Mechanism [1]	Tennessee	$ 2,200
Louisiana	Formula Rate Mechanism [2]	Trans La	4,392
Louisiana	Formula Rate Mechanism	LGS	6,237
Mid-Tex	Formula Rate Mechanism	Dallas	9,976
Mid-Tex	Formula Rate Mechanism	Mid-Tex Cities	43,320
Mid-Tex	Infrastructure Mechanism	Environs	1,568
Mississippi	Infrastructure Mechanism	Mississippi	7,600
West Texas	Infrastructure Mechanism [3]	Cities of Amarillo,Channing, Lubbock, & Dalhart	4,682
West Texas	Infrastructure Mechanism	Environs	872
			$ 80,847

(1) The Tennessee Regulatory Authority (TRA) is currently evaluating a gross filing amount of $6.8 million, of which the TRA issued a final order approving a $4.6 million increase related to the prior year's true-up. The remaining $2.2 million is still under review.

(2) The proposed increase for Trans La customers was implemented on April 1, 2017, subject to refund.

(3) The 2016 GRIP increase was implemented on April 25, 2017.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have formula rate mechanisms in our Louisiana, Mississippi and Tennessee operations and in substantially all of our Texas divisions. Additionally, we have specific infrastructure programs in substantially all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state.

	Annual Formula Rate Mechanisms	
State	**Infrastructure Programs**	**Formula Rate Mechanisms**
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes (Texas only), until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following annual formula rate mechanisms were approved during the six months ended March 31, 2017.

Division	Jurisdiction	Test Year Ended	Increase in Annual Operating Income	Effective Date
			(In thousands)	
2017 Filings:				
Kentucky/Mid-States	Tennessee	05/31/2016	$ 4,612	06/01/2017
West Texas	West Texas Cities	09/30/2016	4,255	03/15/2017
Colorado-Kansas	Kansas	09/30/2016	801	02/09/2017
Mississippi	Mississippi SRF	10/31/2017	4,390	01/12/2017
Mississippi	Mississippi SIR	10/31/2017	3,334	01/01/2017
Mississippi	Mississippi SGR	10/31/2017	1,292	01/01/2017
Colorado-Kansas	Colorado	12/31/2017	1,350	01/01/2017
Kentucky/Mid-States	Kentucky	09/30/2017	4,981	10/14/2016
Kentucky/Mid-States	Virginia	09/30/2017	(378)	10/01/2016
Total 2017 Filings			$ 24,637	

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 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 six months ended March 31, 2017.

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2017 Rate Case Filings:			
Kentucky/Mid-States (1)	Virginia	$ 6	12/27/2016
Total 2017 Rate Case Filings		$ 6	

(1) The Virginia State Corporation Commission issued a final order approving a re-basing of the Company's SAVE rates into base rates and a decrease to depreciation expense. The Company had implemented rates on April 1, 2016, subject to refund, of $0.5 million.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the six months ended March 31, 2017.

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2017 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem(1)	$ 784	2/1/2017
Total 2017 Other Rate Activity			$ 784	

(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.

Pipeline and Storage Segment

Our pipeline and storage segment consists of the pipeline and storage operations of our Atmos Pipeline–Texas Division (APT) and our natural gas transmission operations in Louisiana, which were previously included in our former nonregulated segment. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. APT provides transportation and storage services to our Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, as well as marketers and producers. As part of its pipeline operations, APT manages five underground storage reservoirs in Texas.

Our natural gas transmission operations in Louisiana are comprised of a proprietary 21-mile pipeline located in New Orleans, Louisiana that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. They also manage two asset management plans which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Texas and Louisiana service areas. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation and storage 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 in Texas could influence the volumes of gas transported for shippers through our Texas pipeline system and the rates for such transportation.

The results of APT are also significantly impacted by the natural gas requirements of its local distribution company customers. Additionally, its operations may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

APT annually uses GRIP to recover capital costs incurred in the prior calendar year. However, GRIP also requires a utility to file a statement of intent at least once every five years to review its costs and expenses, including capital costs filed for recovery under GRIP. On January 6, 2017, APT filed its statement of intent seeking $55.2 million in additional annual operating income. APT customarily submits an annual GRIP filing during the second fiscal quarter of each fiscal year. However, APT is precluded from submitting a GRIP filing until a final order has been issued on the statement of intent. Accordingly, APT did not submit its annual GRIP filing during the second quarter of fiscal 2017. The Railroad Commission of Texas has 185 days to issue a final order in this proceeding.

On December 21, 2016, the Louisiana Public Service Commission approved an annual increase of five percent to the demand fee charged by our natural gas transmission pipeline for each of the next 10 years, effective October 1, 2017. This agreement will replace the existing agreement that expires in September 2017.

Three Months Ended March 31, 2017 compared with Three Months Ended March 31, 2016

Financial and operational highlights for our pipeline and storage segment for the three months ended March 31, 2017 and 2016 are presented below.

	Three Months Ended March 31		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Mid-Tex / Affiliate transportation	$ 84,277	$ 74,653	$ 9,624
Third-party transportation	22,839	20,391	2,448
Other	4,131	6,184	(2,053)
Gross profit	111,247	101,228	10,019
Operating expenses	52,879	47,963	4,916
Operating income	58,368	53,265	5,103
Miscellaneous expense	(196)	(367)	171
Interest charges	10,019	9,145	874
Income before income taxes	48,153	43,753	4,400
Income tax expense	17,286	15,830	1,456
Net income	$ 30,867	$ 27,923	$ 2,944
Gross pipeline transportation volumes — MMcf	195,233	187,922	7,311
Consolidated pipeline transportation volumes — MMcf	131,151	115,040	16,111

Net income for our pipeline and storage segment increased 11 percent, primarily due to a $10.0 million increase in gross profit, which is defined as operating revenues less purchased gas cost, offset by a $4.9 million increase in operating expenses. The increase in gross profit primarily reflects a $10.8 million increase in rates from the GRIP filings approved in fiscal 2016. Gross pipeline transportation volumes increased four percent, despite weather that was 34 percent warmer than normal and 23 percent warmer than the prior-year quarter primarily due to volumes associated with EnLink Pipeline, which we acquired in the first fiscal quarter of 2017.

Operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased $4.9 million, primarily due to higher depreciation expense and property taxes associated with increased capital investments.

Six Months Ended March 31, 2017 compared with Six Months Ended March 31, 2016

Financial and operational highlights for our pipeline and storage segment for the six months ended March 31, 2017 and 2016 are presented below.

	Six Months Ended March 31		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Mid-Tex / Affiliate transportation	$ 166,760	$ 144,686	$ 22,074
Third-party transportation	45,044	42,484	2,560
Other	9,040	13,033	(3,993)
Gross profit	220,844	200,203	20,641
Operating expenses	107,451	94,300	13,151
Operating income	113,393	105,903	7,490
Miscellaneous expense	(557)	(769)	212
Interest charges	19,931	18,292	1,639
Income before income taxes	92,905	86,842	6,063
Income tax expense	33,364	31,309	2,055
Net income	$ 59,541	$ 55,533	$ 4,008
Gross pipeline transportation volumes — MMcf	382,013	367,774	14,239
Consolidated pipeline transportation volumes — MMcf	266,127	244,199	21,928

Net income for our pipeline and storage segment increased seven percent, primarily due to a $20.6 million increase in gross profit, which is defined as operating revenues less purchased gas cost, offset by a $13.2 million increase in operating expenses. The increase in gross profit primarily reflects a $21.5 million increase in rates from the GRIP filings approved in fiscal 2016. Gross pipeline transportation volumes increased four percent, despite weather that was 29 percent warmer than normal and 12 percent warmer than the prior-year period, primarily due to volumes associated with EnLink Pipeline.

Operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased $13.2 million, primarily due to increased levels of pipeline maintenance and integrity activities and higher depreciation expense and property taxes associated with increased capital investments.

Natural Gas Marketing Segment

Through December 31, 2016, we were engaged in an unregulated natural gas marketing business, which was conducted by Atmos Energy Marketing (AEM). AEM's primary business was to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. Additionally, AEM utilized proprietary and customer–owned transportation and storage assets to provide various services its customers requested. AEM served most of its customers under contracts generally having one to two year terms. As a result, AEM's margins arose from the types of commercial transactions it had structured with its customers and its ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it had access to serve those customers.

As more fully described in Note 6, effective January 1, 2017, we sold all of the equity interests of AEM to CenterPoint Energy Services, Inc. (CES), a subsidiary of CenterPoint Energy Inc. As a result of the sale, Atmos Energy has fully exited the nonregulated natural gas marketing business. Accordingly, these operations have been reported as discontinued operations.

Three Months Ended March 31, 2017 compared with Three Months Ended March 31, 2016

Financial and operating highlights for our natural gas marketing segment for the three months ended March 31, 2017 and 2016 are presented below.

	Three Months Ended March 31		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ —	$ 5,260	$ (5,260)
Operating expenses	—	6,900	(6,900)
Operating loss	—	(1,640)	1,640
Miscellaneous income	—	39	(39)
Interest charges	—	396	(396)
Loss before income taxes	—	(1,997)	1,997
Income tax benefit	—	(804)	804
Loss from discontinued operations	—	(1,193)	1,193
Gain on sale of discontinued operations, net of tax	2,716	—	2,716
Net income (loss) from discontinued operations	$ 2,716	$ (1,193)	$ 3,909
Gross natural gas marketing delivered gas sales volumes — MMcf	—	102,977	(102,977)
Consolidated natural gas marketing delivered gas sales volumes — MMcf	—	91,366	(91,366)
Net physical position (Bcf)	—	35.2	(35.2)

The $3.9 million quarter-over-quarter increase in net income from discontinued operations primarily reflects the recognition of a net $2.7 million gain on sale upon completion of the sale of AEM to CES in January 2017.

Six Months Ended March 31, 2017 compared with Six Months Ended March 31, 2016

Financial and operating highlights for our natural gas marketing segment for the six months ended March 31, 2017 and 2016 are presented below.

	Six Months Ended March 31		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Gross profit	$ 25,920	$ 14,729	$ 11,191
Operating expenses	7,874	12,893	(5,019)
Operating income	18,046	1,836	16,210
Miscellaneous income	30	115	(85)
Interest charges	241	1,748	(1,507)
Income before income taxes	17,835	203	17,632
Income tax expense	6,841	81	6,760
Income from discontinued operations	10,994	122	10,872
Gain on sale of discontinued operations, net of tax	2,716	—	2,716
Net income from discontinued operations	$ 13,710	$ 122	$ 13,588
Gross nonregulated delivered gas sales volumes — MMcf	90,223	196,173	(105,950)
Consolidated nonregulated delivered gas sales volumes — MMcf	78,646	172,960	(94,314)
Net physical position (Bcf)	—	35.2	(35.2)

The $13.6 million year-over-year increase in net income from discontinued operations primarily reflects the recognition of a net $6.6 million noncash gain from unwinding hedge accounting for certain of the natural gas marketing business's financial positions. Due to the anticipated sale of AEM, we determined that the cash flows associated with our natural gas marketing commodity cash flow hedges were no longer probable of occurring; therefore, we discontinued hedge accounting as of December 31, 2016. As a result, we reclassified the gains in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of purchased gas costs and recognized a pre-tax gain of $10.6 million during the first fiscal quarter of 2017. Additionally, we recognized a $2.7 million net gain on sale upon completion of the sale of AEM to CES in January 2017.

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 45 to 55 percent. We also evaluate the levels of committed borrowing capacity that we require. We currently have over $1.5 billion of capacity under 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 registration statement on file with the SEC that permits us to issue a total of $2.5 billion in common stock and/or debt securities. Under the shelf registration statement, we have filed a prospectus supplement for an at–the-market (ATM) equity distribution program under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. At March 31, 2017, approximately $2.4 billion of securities remain available for issuance under the shelf registration statement and approximately $50 million of equity remained available for issuance under the ATM program.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of March 31, 2017, September 30, 2016 and March 31, 2016:

	March 31, 2017		September 30, 2016		March 31, 2016	
	(In thousands, except percentages)					
Short-term debt	$ 670,607	9.5%	$ 829,811	12.3%	$ 626,929	9.8%
Long-term debt(1)	2,564,620	36.3%	2,438,779	36.2%	2,438,304	38.0%
Shareholders' equity	3,834,864	54.2%	3,463,059	51.5%	3,344,565	52.2%
Total	$ 7,070,091	100.0%	$ 6,731,649	100.0%	$ 6,409,798	100.0%

(1) In June 2017, $250 million of long-term debt will mature. We plan to issue new senior notes to replace this maturing debt. We have executed forward starting interest rate swaps to effectively fix the Treasury yield component associated with this anticipated issuance at 3.37%.

Cash Flows

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

Cash flows from operating, investing and financing activities for the six months ended March 31, 2017 and 2016 are presented below.

	Six Months Ended March 31		
	2017	2016	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 552,003	$ 452,955	$ 99,048
Investing activities	(516,670)	(533,524)	16,854
Financing activities	(37,464)	99,834	(137,298)
Change in cash and cash equivalents	(2,131)	19,265	(21,396)
Cash and cash equivalents at beginning of period	47,534	28,653	18,881
Cash and cash equivalents at end of period	$ 45,403	$ 47,918	$ (2,515)

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

For the six months ended March 31, 2017, we generated cash flow of $552.0 million from operating activities compared with $453.0 million for the six months ended March 31, 2016. The $99.0 million increase in operating cash flows reflects the positive cash effects of successful rate case outcomes achieved in fiscal 2016 and changes in working capital.

Cash flows from investing activities

In executing our regulatory strategy, we target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions 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 our ongoing construction program, which enables us to enhance the safety and reliability of the systems used to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. Over the last three fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system. We anticipate our annual capital spending will be in the range of $1 billion to $1.4 billion through fiscal 2020.

For the six months ended March 31, 2017, cash used for investing activities was $516.7 million compared to $533.5 million in the prior-year period. Capital spending rose a net $23.4 million, or 4.4 percent, as a result of planned increases in our distribution segment to repair and replace vintage pipelines, partially offset by a decrease in spending in our pipeline and storage segment as a result of the substantial completion of an APT project to improve the reliability of gas service to its local distribution company customers. Cash flows from investing activities also include proceeds of $133.6 million received from the sale of AEM, and the $85.7 million purchase price for EnLink Pipeline in the first fiscal quarter of 2017.

Cash flows from financing activities

For the six months ended March 31, 2017, our financing activities used $37.5 million of cash compared with $99.8 million generated in the prior-year period. The $137.3 million increase in cash used for financing is primarily due to net repayments of short-term debt in the current-year period, offset by borrowings under our three year, $200 million multi-draw floating-rate term loan agreement, proceeds received from the issuance of common stock under our ATM program during the first quarter and the return of cash collateral related to our forward-starting interest rate swaps due to an increase in interest rates in the first quarter.

The following table summarizes our share issuances for the six months ended March 31, 2017 and 2016.

	Six Months Ended March 31	
	2017	2016
Shares issued:		
Direct Stock Purchase Plan	54,366	78,652
1998 Long-Term Incentive Plan	426,835	458,929
Retirement Savings Plan and Trust	172,932	193,106
At-the-Market (ATM) Equity Distribution Program	690,812	
Total shares issued	1,344,945	730,687

The year-over-year increase in the number of shares issued primarily reflects shares issued under the ATM Program in the current year.

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 $1.5 billion commercial paper program and three committed revolving credit facilities with third-party lenders that provide a total of approximately $1.5 billion of working capital funding. As of March 31, 2017, the amount available to us under our credit facilities, net of commercial paper and outstanding letters of credit, was $0.9 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 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 March 31, 2017, all three rating agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

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

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

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

Debt Covenants

We were in compliance with all of our debt covenants as of March 31, 2017. 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 9 to the unaudited condensed consolidated financial statements, there were no significant changes in our contractual obligations and commercial commitments during the six months ended March 31, 2017.

Risk Management Activities

In our distribution and pipeline and storage segments, 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. Through December 31, 2016, we managed our exposure to the risk of natural gas price changes in our natural gas marketing segment by locking 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.

The following table shows the components of the change in fair value of our financial instruments for the three and six months ended March 31, 2017 and 2016:

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
	(In thousands)			
Fair value of contracts at beginning of period	$ (121,722)	$ (130,282)	$ (279,543)	$ (153,981)
Contracts realized/settled	1,793	(6,279)	11,756	(11)
Fair value of new contracts	(2,560)	240	(1,597)	57
Other changes in value	8,485	(67,628)	155,380	(50,014)
Fair value of contracts at end of period	(114,004)	(203,949)	(114,004)	(203,949)
Netting of cash collateral	—	25,582	—	25,582
Cash collateral and fair value of contracts at period end	$ (114,004)	$ (178,367)	$ (114,004)	$ (178,367)

The fair value of our financial instruments at March 31, 2017 is presented below by time period and fair value source:

	Fair Value of Contracts at March 31, 2017				
	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	$ (19,748)	$ (94,256)	$ —	$ —	$ (114,004)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ (19,748)	$ (94,256)	$ —	$ —	$ (114,004)

Pension and Postretirement Benefits Obligations

For the six months ended March 31, 2017 and 2016, our total net periodic pension and other benefits costs were $23.2 million and $23.0 million. A substantial portion of those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2017 costs were determined using a September 30, 2016 measurement date. As of September 30, 2016, interest and corporate bond rates were lower than the rates as of September 30, 2015. Therefore, we decreased the discount rate used to measure our fiscal 2017 net periodic cost from 4.55 percent to 3.73 percent. We maintained the expected return on plan assets of 7.00 percent in the determination of our fiscal 2017 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2017 net periodic pension cost to be generally consistent with fiscal 2016.

The amount with which we fund our defined benefit plan is determined in accordance with the Pension Protection Act of 2006 (PPA) and is influenced by the funded position of the plan when the funding requirements are determined on January 1 of each year. Based upon the determination as of January 1, 2017, we are not required to make a minimum contribution to our defined benefit plan during fiscal 2017. However, we will consider whether a voluntary contribution is prudent to maintain certain funding levels.

For the six months ended March 31, 2017 we contributed $6.6 million to our postretirement medical plans. We anticipate contributing a total of between $10 million and $20 million to our postretirement plans during fiscal 2017.

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

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our distribution and pipeline and storage segments for the three and six-month periods ended March 31, 2017 and 2016.

Distribution Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
METERS IN SERVICE, end of period				
Residential	2,929,455	2,899,265	2,929,455	2,899,265
Commercial	269,055	267,213	269,055	267,213
Industrial	1,690	1,828	1,690	1,828
Public authority and other	8,332	8,410	8,332	8,410
Total meters	3,208,532	3,176,716	3,208,532	3,176,716
INVENTORY STORAGE BALANCE — Bcf	40.0	40.2	40.0	40.2
SALES VOLUMES — MMcf[1]				
Gas sales volumes				
Residential	56,931	68,758	98,431	108,927
Commercial	31,739	35,854	55,475	59,272
Industrial	6,708	8,897	14,140	15,890
Public authority and other	2,376	2,861	4,138	4,535
Total gas sales volumes	97,754	116,370	172,184	188,624
Transportation volumes	42,142	43,986	81,207	79,110
Total throughput	139,896	160,356	253,391	267,734
OPERATING REVENUES (000's)[1]				
Gas sales revenues				
Residential	$ 609,771	$ 563,565	$ 1,091,444	$ 979,550
Commercial	251,174	222,480	451,662	394,505
Industrial	47,986	29,643	78,017	54,401
Public authority and other	17,607	16,560	29,716	27,093
Total gas sales revenues	926,538	832,248	1,650,839	1,455,549
Transportation revenues	24,307	22,623	46,788	42,105
Other gas revenues	11,696	7,256	19,570	13,916
Total operating revenues	$ 962,541	$ 862,127	$ 1,717,197	$ 1,511,570
Average cost of gas per Mcf sold	$ 5.25	$ 3.87	$ 5.28	$ 4.05

See footnote following these tables.

Pipeline and Storage Operations Sales and Statistical Data

	Three Months Ended March 31		Six Months Ended March 31	
	2017	2016	2017	2016
CUSTOMERS, end of period				
Industrial	91	88	91	88
Other	226	221	226	221
Total	317	309	317	309
INVENTORY STORAGE BALANCE — Bcf	0.6	1.8	0.6	1.8
PIPELINE TRANSPORTATION VOLUMES — MMcf[(1)]	195,233	187,922	382,013	367,774
OPERATING REVENUES (000's)[(1)]	$ 111,972	$ 102,153	$ 221,924	$ 200,569

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, 2016. During the six months ended March 31, 2017, except for the effects of the sale of AEM on our market risk, there were no material changes in our quantitative and qualitative disclosures about market risk.

Item 4. *Controls and Procedures*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of March 31, 2017 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the second quarter of the fiscal year ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the six months ended March 31, 2017, there were no material changes in the status of the litigation and other matters that were disclosed in Note 11 to our Annual Report on Form 10-K for the fiscal year ended September 30, 2016. 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/ CHRISTOPHER T. FORSYTHE

Christopher T. Forsythe
Senior Vice President and
Chief Financial Officer
(Duly authorized signatory)

Date: May 4, 2017

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
2.1	Membership Interest Purchase Agreement by and between Atmos Energy Holdings, Inc. as Seller and CenterPoint Energy Services, Inc. as Buyer, dated as of October 29, 2016	Exhibit 2.1 to Form 8-K dated October 29, 2016 (File No. 1-10042)
10	Equity Distribution Agreement, dated as of March 28, 2016, among Atmos Energy Corporation, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC.	Exhibit 1.1 to Form 8-K dated March 28, 2016 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

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

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2017

or

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

For the transition period from to

Commission File Number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐ Emerging growth company ☐
(Do not check if a smaller reporting company)

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

Number of shares outstanding of each of the issuer's classes of common stock, as of July 28, 2017.

Class	**Shares Outstanding**
No Par Value	106,065,596

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
GAAP	Generally Accepted Accounting Principles
GRIP	Gas Reliability Infrastructure Program
Gross Profit	Non-GAAP measure defined as operating revenues less purchased gas cost
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, 2017	September 30, 2016
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$ 10,952,422	$ 10,142,506
Less accumulated depreciation and amortization	2,028,041	1,873,900
Net property, plant and equipment	8,924,381	8,268,606
Current assets		
Cash and cash equivalents	69,777	47,534
Accounts receivable, net	250,224	215,880
Gas stored underground	151,656	179,070
Current assets of disposal group classified as held for sale	—	151,117
Other current assets	62,725	88,085
Total current assets	534,382	681,686
Goodwill	729,673	726,962
Noncurrent assets of disposal group classified as held for sale	—	28,616
Deferred charges and other assets	310,339	305,019
	$ 10,498,775	$ 10,010,889
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $0.005 per share); 200,000,000 shares authorized; issued and outstanding: June 30, 2017 — 106,059,875 shares; September 30, 2016 — 103,930,560 shares	$ 530	$ 520
Additional paid-in capital	2,525,752	2,388,027
Accumulated other comprehensive loss	(104,599)	(188,022)
Retained earnings	1,480,027	1,262,534
Shareholders' equity	3,901,710	3,463,059
Long-term debt	3,066,734	2,188,779
Total capitalization	6,968,444	5,651,838
Current liabilities		
Accounts payable and accrued liabilities	164,365	196,485
Current liabilities of disposal group classified as held for sale	—	72,900
Other current liabilities	322,721	439,085
Short-term debt	258,573	829,811
Current maturities of long-term debt	—	250,000
Total current liabilities	745,659	1,788,281
Deferred income taxes	1,853,564	1,603,056
Regulatory cost of removal obligation	457,060	424,281
Pension and postretirement liabilities	304,919	297,743
Noncurrent liabilities of disposal group held for sale	—	316
Deferred credits and other liabilities	169,129	245,374
	$ 10,498,775	$ 10,010,889

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2017	2016
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Distribution segment	$ 494,060	$ 424,905
Pipeline and storage segment	117,283	113,855
Intersegment eliminations	(84,842)	(82,548)
Total operating revenues	526,501	456,212
Purchased gas cost		
Distribution segment	197,767	147,569
Pipeline and storage segment	1,251	(438)
Intersegment eliminations	(84,842)	(82,548)
Total purchased gas cost	114,176	64,583
Operation and maintenance expense	128,690	131,388
Depreciation and amortization expense	80,023	72,880
Taxes, other than income	62,948	58,965
Operating income	140,664	128,396
Miscellaneous (expense) income	(289)	1,118
Interest charges	28,498	27,679
Income from continuing operations before income taxes	111,877	101,835
Income tax expense	41,069	35,692
Income from continuing operations	70,808	66,143
Income from discontinued operations, net of tax ($0 and $3,414)	—	5,050
Net Income	$ 70,808	$ 71,193
Basic and diluted net income per share		
Income per share from continuing operations	$ 0.67	$ 0.64
Income per share from discontinued operations	—	0.05
Net income per share - basic and diluted	$ 0.67	$ 0.69
Cash dividends per share	$ 0.45	$ 0.42
Basic and diluted weighted average shares outstanding	106,364	103,750

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30 2017	Nine Months Ended June 30 2016
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Distribution segment	$ 2,211,257	$ 1,936,475
Pipeline and storage segment	339,207	314,424
Intersegment eliminations	(255,609)	(229,894)
Total operating revenues	2,294,855	2,021,005
Purchased gas cost		
Distribution segment	1,106,209	912,231
Pipeline and storage segment	2,331	(72)
Intersegment eliminations	(255,565)	(229,894)
Total purchased gas cost	852,975	682,265
Operation and maintenance expense	385,867	379,073
Depreciation and amortization expense	234,648	214,927
Taxes, other than income	185,611	171,959
Operating income	635,754	572,781
Miscellaneous expense	(450)	(90)
Interest charges	86,472	84,775
Income from continuing operations before income taxes	548,832	487,916
Income tax expense	201,974	177,224
Income from continuing operations	346,858	310,692
Income from discontinued operations, net of tax ($6,841 and $3,495)	10,994	5,172
Gain on sale of discontinued operations, net of tax ($10,215 and $0)	2,716	—
Net Income	$ 360,568	$ 315,864
Basic and diluted net income per share		
Income per share from continuing operations	$ 3.27	$ 3.01
Income per share from discontinued operations	0.13	0.05
Net income per share - basic and diluted	$ 3.40	$ 3.06
Cash dividends per share	$ 1.35	$ 1.26
Basic and diluted weighted average shares outstanding	105,862	103,137

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	
	2017	2016	2017	2016
	(Unaudited) (In thousands)			
Net income	$ 70,808	$ 71,193	$ 360,568	$ 315,864
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $490, $110, $893 and $(837)	851	151	1,553	(1,496)
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $(10,667), $(22,561), $44,194 and $(50,631)	(18,556)	(39,250)	76,888	(88,085)
Net unrealized gains on commodity cash flow hedges, net of tax of $0, $11,575, $3,183 and $13,220	—	18,105	4,982	20,678
Total other comprehensive income (loss)	(17,705)	(20,994)	83,423	(68,903)
Total comprehensive income	$ 53,103	$ 50,199	$ 443,991	$ 246,961

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2017	2016
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$ 360,568	$ 315,864
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	234,833	216,670
Deferred income taxes	188,256	171,042
Gain on sale of discontinued operations	(12,931)	—
Discontinued cash flow hedging for natural gas marketing commodity contracts	(10,579)	—
Other	14,892	14,430
Net assets / liabilities from risk management activities	25,661	7,973
Net change in operating assets and liabilities	(55,139)	(96,033)
Net cash provided by operating activities	745,561	629,946
Cash Flows From Investing Activities		
Capital expenditures	(812,148)	(789,688)
Acquisition	(86,128)	—
Proceeds from the sale of discontinued operations	140,253	—
Available-for-sale securities activities, net	(14,329)	558
Use tax refund	18,562	—
Other, net	6,435	5,731
Net cash used in investing activities	(747,355)	(783,399)
Cash Flows From Financing Activities		
Net (decrease) increase in short-term debt	(571,238)	212,539
Net proceeds from equity offering	98,755	98,660
Issuance of common stock through stock purchase and employee retirement plans	22,673	26,500
Proceeds from issuance of long-term debt	884,911	—
Settlement of interest rate agreements	(36,996)	—
Interest rate agreements cash collateral	25,670	(16,330)
Repayment of long-term debt	(250,000)	—
Cash dividends paid	(143,075)	(130,363)
Debt issuance costs	(6,663)	—
Net cash provided by financing activities	24,037	191,006
Net increase in cash and cash equivalents	22,243	37,553
Cash and cash equivalents at beginning of period	47,534	28,653
Cash and cash equivalents at end of period	$ 69,777	$ 66,206

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2017

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") is engaged in the regulated natural gas distribution and pipeline and storage businesses. 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 divisions and subsidiaries operate.

Our distribution business delivers natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six natural gas distribution divisions, which at June 30, 2017, covered service areas located in eight states.

Our pipeline and storage business includes the transportation of natural gas to Texas and Louisiana distribution systems and the management of our underground storage facilities used to support Texas distribution businesses.

Effective January 1, 2017, we completed the sale of all of the equity interests of Atmos Energy Marketing (AEM) to CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy, Inc. (CES). Accordingly, AEM's historical financial results are reflected in the Company's condensed consolidated financial statements as discontinued operations, which required retrospective application to financial information for all periods presented. Refer to Note 6 for further information. Our discontinued natural gas marketing segment was primarily engaged in a nonregulated natural gas marketing business, conducted by AEM. This business provided natural gas management and transportation services to municipalities, regulated 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 for the fiscal year ended September 30, 2016, which appear in Exhibit 99.1 to our Current Report on Form 8-K dated April 12, 2017 (the "Fiscal 2016 Financial Statements"). 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 our Fiscal 2016 Financial Statements. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2017 are not indicative of our results of operations for the full 2017 fiscal year, which ends September 30, 2017.

During the third quarter, we completed a State of Texas use tax audit that covered the period from October 2011 to March 2017, which resulted in a refund of $29.8 million. We concluded the appropriate regulatory treatment of this refund was to reduce rate base. We received $18.7 million during the third quarter, which has been included in cash flows from investing activities, and recorded an $11.1 million receivable as of June 30, 2017.

On January 6, 2017, our Atmos Pipeline - Texas Division filed its statement of intent seeking $63.6 million, as adjusted in its rebuttal case, in additional annual operating income. On August 1, 2017, a final order was issued in our APT rate case resulting in a $13.0 million increase in annual operating income. No other 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 of our Fiscal 2016 Financial Statements.

As discussed in Note 3, due to the realignment of our reportable segments, prior periods' segment information has been recast in accordance with applicable accounting guidance. Additionally, as discussed in Note 6, due to the sale of AEM, prior period amounts have been presented as discontinued operations. The segment realignment and the presentation of discontinued operations have not impacted our reported net income, financial position or cash flows.

During the second quarter of fiscal 2017, 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, an entity 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 may need to use more judgment and make more estimates than under current guidance.

The new guidance will become effective for us 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.

As of June 30, 2017, we have substantially completed the evaluation of our sources of revenue and are currently assessing the effect that the new guidance will have on our financial position, results of operations, cash flows and business processes. The conclusion of our assessment is contingent, in part, upon the completion of deliberations currently in progress by our industry, notably in connection with efforts to produce an accounting guide intended to be developed by the American Institute of Certified Public Accountants (AICPA).

In association with this undertaking, the AICPA formed a number of industry task forces, including a Power & Utilities (P&U) Task Force. Industry representatives and organizations, the largest auditing firms, the AICPA's Revenue Recognition Working Group and its Financial Reporting Executive Committee have undertaken, and continue to undertake, consideration of several items relevant to our industry as further discussed below. Where applicable or necessary, the FASB's Transition Resource Group (TRG) is also participating.

Additionally, we are actively working with our peers in the rate-regulated natural gas industry and with the public accounting profession to conclude on the accounting treatment for several other issues that are not expected to be addressed by the P&U Task Force. Based on the progress of these deliberations to date, we currently do not believe the implementation of the new guidance will have a material effect on our financial position, results of operations, cash flows or business processes. We are currently still evaluating the transition method we will utilize to adopt the new guidance as well as the impact to our financial statement presentation and related disclosures.

In May 2015, the FASB issued guidance removing the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. The guidance was effective for us on October 1, 2016, to be applied retrospectively. We measure certain pension plan assets using the net asset value per share practical expedient, which are disclosed on an annual basis in our Form 10-K. The adoption of the new standard should have no material impact on our results of operations, consolidated balance sheets or cash flows.

In January 2016, the FASB issued guidance related to the classification and measurement of financial instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning October 1, 2018; limited early adoption is permitted. We are currently evaluating the potential impact of this new guidance on our financial position, results of operations and cash flows.

In February 2016, the FASB issued a comprehensive new leasing standard that will require lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The new standard will be effective for us beginning on October 1, 2019; early adoption is permitted. The new leasing standard requires modified retrospective transition, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. As of June 30, 2017, we had begun the process of identifying and categorizing our lease contracts, evaluating our current business processes and identifying a lease software solution. We are currently evaluating the effect on our financial position, results of operations and cash flows.

In June 2016, the FASB issued new guidance which will require credit losses on most financial assets measured at amortized cost and certain other instruments to be measured using an expected credit loss model. Under this model, entities will estimate credit losses over the entire contractual term of the instrument from the date of initial recognition of that instrument. In contrast, current U.S. GAAP is based on an incurred loss model that delays recognition of credit losses until it is probable the loss has been incurred. The new guidance also introduces a new impairment recognition model for available-for-sale securities that will require credit losses for available-for-sale debt securities to be recorded through an allowance account. The new standard will be effective for us beginning on October 1, 2021; early adoption is permitted beginning on October 1, 2019. We are currently evaluating the potential impact of this new guidance on our financial position, results of operations and cash flows.

In January 2017, the FASB issued new guidance that simplifies the accounting for goodwill impairments by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the total amount of goodwill allocated to that reporting unit. The new standard will be effective for our fiscal 2021 goodwill impairment test; however, early adoption is permitted for goodwill impairment tests performed on testing dates after January 1, 2017. The adoption of the new standard will have no impact on our results of operations, consolidated balance sheets or cash flows.

In March 2017, the FASB issued new guidance related to the income statement presentation of the components of net periodic benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. The new guidance requires entities to disaggregate the current service cost component of the net benefit cost from the other components and present it with other current compensation costs for related employees in the statement of income. The other components of net benefit cost will be presented outside of income from operations on the statement of income. In addition, only the service cost component of net benefit cost is eligible for capitalization (e.g., as part of inventory or property, plant, and equipment). The new guidance is effective for us in the fiscal year beginning on October 1, 2018 and for interim periods within that year. We are currently evaluating the potential impact of this new guidance on our financial position, results of operations and cash flows.

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, 2017 and September 30, 2016 included the following:

	June 30, 2017	September 30, 2016
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs(1)	$ 122,202	$ 132,348
Infrastructure mechanisms(2)	38,653	42,719
Deferred gas costs	16,405	45,184
Recoverable loss on reacquired debt	11,843	13,761
Deferred pipeline record collection costs	10,327	7,336
APT annual adjustment mechanism	4,973	7,171
Rate case costs	2,480	1,539
Other	9,949	13,565
	$ 216,832	$ 263,623
Regulatory liabilities:		
Regulatory cost of removal obligations	$ 492,404	$ 476,891
Deferred gas costs	16,753	20,180
Asset retirement obligations	13,404	13,404
Other	6,729	4,250
	$ 529,290	$ 514,725

(1) Includes $11.5 million and $12.4 million of pension and postretirement expense deferred pursuant to regulatory authorization.
(2) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all eligible expenses associated with capital expenditures incurred pursuant to these rules, including the recording of interest on deferred expenses until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

3. Segment Information

Through November 30, 2016, our consolidated operations were managed and reviewed through three segments:

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

As a result of the announced sale of Atmos Energy Marketing, we revised the information used by the chief operating decision maker to manage the Company, effective December 1, 2016. Accordingly, we have been managing and reviewing our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states and storage assets located in Kentucky and Tennessee, which are used solely to support our natural gas distribution operations in those states. These storage assets were formerly included in our nonregulated segment.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana, which were formerly included in our nonregulated segment.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

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 distribution segment operations are geographically dispersed, they are aggregated and reported as a single segment as each natural gas distribution division has similar economic characteristics. In addition, because the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana have similar economic characteristics, they have been aggregated and reported as a single segment.

The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Fiscal 2016 Financial Statements. We evaluate performance based on net income or loss of the respective operating segments. We allocate interest and pension expense to the pipeline and storage segment; however, there is no debt or pension liability recorded on the pipeline and storage segment balance sheet. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Prior periods' segment information has been recast as required by applicable accounting guidance. The segment realignment has not impacted our reported consolidated revenues or net income.

Income statements for the three and nine months ended June 30, 2017 and 2016 by segment are presented in the following tables:

	Three Months Ended June 30, 2017				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 493,738	$ 32,763	$ —	$ —	$ 526,501
Intersegment revenues	322	84,520	—	(84,842)	—
Total operating revenues	494,060	117,283	—	(84,842)	526,501
Purchased gas cost	197,767	1,251	—	(84,842)	114,176
Operation and maintenance expense	99,631	29,059	—	—	128,690
Depreciation and amortization expense	62,760	17,263	—	—	80,023
Taxes, other than income	56,850	6,098	—	—	62,948
Operating income	77,052	63,612	—	—	140,664
Miscellaneous expense	(62)	(227)	—	—	(289)
Interest charges	18,394	10,104	—	—	28,498
Income before income taxes	58,596	53,281	—	—	111,877
Income tax expense	22,082	18,987	—	—	41,069
Net income	$ 36,514	$ 34,294	$ —	$ —	$ 70,808
Capital expenditures	$ 205,780	$ 46,983	$ —	$ —	$ 252,763

	Three Months Ended June 30, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 424,553	$ 31,659	$ —	$ —	$ 456,212
Intersegment revenues	352	82,196	—	(82,548)	—
Total operating revenues	424,905	113,855	—	(82,548)	456,212
Purchased gas cost	147,569	(438)	—	(82,548)	64,583
Operation and maintenance expense	101,819	29,569	—	—	131,388
Depreciation and amortization expense	59,193	13,687	—	—	72,880
Taxes, other than income	52,662	6,303	—	—	58,965
Operating income	63,662	64,734	—	—	128,396
Miscellaneous income (expense)	1,243	(125)	—	—	1,118
Interest charges	18,677	9,002	—	—	27,679
Income from continuing operations before income taxes	46,228	55,607	—	—	101,835
Income tax expense	15,867	19,825	—	—	35,692
Income from continuing operations	30,361	35,782	—	—	66,143
Income from discontinued operations, net of tax	—	—	5,050	—	5,050
Net income	$ 30,361	$ 35,782	$ 5,050	$ —	$ 71,193
Capital expenditures	$ 187,470	$ 66,108	$ 106	$ —	$ 253,684

	Nine Months Ended June 30, 2017				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 2,210,221	$ 84,634	$ —	$ —	$ 2,294,855
Intersegment revenues	1,036	254,573	—	(255,609)	—
Total operating revenues	2,211,257	339,207	—	(255,609)	2,294,855
Purchased gas cost	1,106,209	2,331	—	(255,565)	852,975
Operation and maintenance expense	296,048	89,863	—	(44)	385,867
Depreciation and amortization expense	185,219	49,429	—	—	234,648
Taxes, other than income	165,032	20,579	—	—	185,611
Operating income	458,749	177,005	—	—	635,754
Miscellaneous income (expense)	334	(784)	—	—	(450)
Interest charges	56,437	30,035	—	—	86,472
Income from continuing operations before income taxes	402,646	146,186	—	—	548,832
Income tax expense	149,623	52,351	—	—	201,974
Income from continuing operations	253,023	93,835	—	—	346,858
Income from discontinued operations, net of tax	—	—	10,994	—	10,994
Gain on sale of discontinued operations, net of tax	—	—	2,716	—	2,716
Net income	$ 253,023	$ 93,835	$ 13,710	$ —	$ 360,568
Capital expenditures	$ 636,449	$ 175,699	$ —	$ —	$ 812,148

	Nine Months Ended June 30, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$ 1,935,421	$ 85,584	$ —	$ —	$ 2,021,005
Intersegment revenues	1,054	228,840	—	(229,894)	—
Total operating revenues	1,936,475	314,424	—	(229,894)	2,021,005
Purchased gas cost	912,231	(72)	—	(229,894)	682,265
Operation and maintenance expense	294,154	84,919	—	—	379,073
Depreciation and amortization expense	174,748	40,179	—	—	214,927
Taxes, other than income	153,198	18,761	—	—	171,959
Operating income	402,144	170,637	—	—	572,781
Miscellaneous income (expense)	804	(894)	—	—	(90)
Interest charges	57,481	27,294	—	—	84,775
Income from continuing operations before income taxes	345,467	142,449	—	—	487,916
Income tax expense	126,090	51,134	—	—	177,224
Income from continuing operations	219,377	91,315	—	—	310,692
Income from discontinued operations, net of tax	—	—	5,172	—	5,172
Net income	$ 219,377	$ 91,315	$ 5,172	$ —	$ 315,864
Capital expenditures	$ 528,063	$ 261,446	$ 179	$ —	$ 789,688

Balance sheet information at June 30, 2017 and September 30, 2016 by segment is presented in the following tables:

	June 30, 2017				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 6,678,875	$ 2,245,506	$ —	$ —	$ 8,924,381
Investment in subsidiaries	798,994	13,851	—	(812,845)	—
Current assets					
Cash and cash equivalents	69,777	—	—	—	69,777
Other current assets	437,700	29,265	—	(2,360)	464,605
Intercompany receivables	983,866	—	—	(983,866)	—
Total current assets	1,491,343	29,265	—	(986,226)	534,382
Goodwill	586,661	143,012	—	—	729,673
Deferred charges and other assets	280,240	30,099	—	—	310,339
	$ 9,836,113	$ 2,461,733	$ —	$ (1,799,071)	$ 10,498,775
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,901,710	$ 812,845	$ —	$ (812,845)	$ 3,901,710
Long-term debt	3,066,734	—	—	—	3,066,734
Total capitalization	6,968,444	812,845	—	(812,845)	6,968,444
Current liabilities					
Short-term debt	258,573	—	—	—	258,573
Other current liabilities	451,026	38,420	—	(2,360)	487,086
Intercompany payables	—	983,866	—	(983,866)	—
Total current liabilities	709,599	1,022,286	—	(986,226)	745,659
Deferred income taxes	1,251,528	602,036	—	—	1,853,564
Regulatory cost of removal obligation	432,531	24,529	—	—	457,060
Pension and postretirement liabilities	304,919	—	—	—	304,919
Deferred credits and other liabilities	169,092	37	—	—	169,129
	$ 9,836,113	$ 2,461,733	$ —	$ (1,799,071)	$ 10,498,775

	September 30, 2016				
	Distribution	Pipeline and Storage	Natural Gas Marketing	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$ 6,208,465	$ 2,060,141	$ —	$ —	$ 8,268,606
Investment in subsidiaries	768,415	13,854	—	(782,269)	—
Current assets					
Cash and cash equivalents	22,117	—	25,417	—	47,534
Current assets of disposal group classified as held for sale	—	—	162,508	(11,391)	151,117
Other current assets	489,963	39,078	5	(46,011)	483,035
Intercompany receivables	971,665	—	—	(971,665)	—
Total current assets	1,483,745	39,078	187,930	(1,029,067)	681,686
Goodwill	583,950	143,012	—	—	726,962
Noncurrent assets of disposal group classified as held for sale	—	—	28,785	(169)	28,616
Deferred charges and other assets	277,240	27,779	—	—	305,019
	$ 9,321,815	$ 2,283,864	$ 216,715	$ (1,811,505)	$ 10,010,889
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 3,463,059	$ 715,672	$ 66,597	$ (782,269)	$ 3,463,059
Long-term debt	2,188,779	—	—	—	2,188,779
Total capitalization	5,651,838	715,672	66,597	(782,269)	5,651,838
Current liabilities					
Current maturities of long-term debt	250,000	—	—	—	250,000
Short-term debt	829,811	—	35,000	(35,000)	829,811
Current liabilities of the disposal group classified as held for sale	—	—	81,908	(9,008)	72,900
Other current liabilities	605,790	39,911	3,263	(13,394)	635,570
Intercompany payables	—	957,526	14,139	(971,665)	—
Total current liabilities	1,685,601	997,437	134,310	(1,029,067)	1,788,281
Deferred income taxes	1,055,348	543,390	4,318	—	1,603,056
Regulatory cost of removal obligation	397,162	27,119	—	—	424,281
Pension and postretirement liabilities	297,743	—	—	—	297,743
Noncurrent liabilities of disposal group classified as held for sale	—	—	316	—	316
Deferred credits and other liabilities	234,123	246	11,174	(169)	245,374
	$ 9,321,815	$ 2,283,864	$ 216,715	$ (1,811,505)	$ 10,010,889

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, 2017 and 2016 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2017	2016	2017	2016
	(In thousands, except per share amounts)			
Basic and Diluted Earnings Per Share from continuing operations				
Income from continuing operations	$ 70,808	$ 66,143	$ 346,858	$ 310,692
Less: Income from continuing operations allocated to participating securities	75	100	424	488
Income from continuing operations available to common shareholders	$ 70,733	$ 66,043	$ 346,434	$ 310,204
Basic and diluted weighted average shares outstanding	106,364	103,750	105,862	103,137
Income from continuing operations per share — Basic and Diluted	$ 0.67	$ 0.64	$ 3.27	$ 3.01
Basic and Diluted Earnings Per Share from discontinued operations				
Income from discontinued operations	$ —	$ 5,050	$ 13,710	$ 5,172
Less: Income from discontinued operations allocated to participating securities	—	6	15	4
Income from discontinued operations available to common shareholders	$ —	$ 5,044	$ 13,695	$ 5,168
Basic and diluted weighted average shares outstanding	106,364	103,750	105,862	103,137
Income from discontinued operations per share — Basic and Diluted	$ —	$ 0.05	$ 0.13	$ 0.05
Net income per share — Basic and Diluted	$ 0.67	$ 0.69	$ 3.40	$ 3.06

5. Debt

The nature and terms of our debt instruments and credit facilities are described in detail in Note 5 in our Fiscal 2016 Financial Statements. Except as noted below, there were no material changes in the terms of our debt instruments during the nine months ended June 30, 2017.

Long-term debt at June 30, 2017 and September 30, 2016 consisted of the following:

	June 30, 2017	September 30, 2016
	(In thousands)	
Unsecured 6.35% Senior Notes, due June 2017	$ —	$ 250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 3.00% Senior Notes, due 2027	500,000	—
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	750,000	500,000
Medium-term note Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Floating-rate term loan, due 2019	125,000	—
Total long-term debt	3,085,000	2,460,000
Less:		
Original issue (premium) discount on unsecured senior notes and debentures	(4,370)	4,270
Debt issuance cost	22,636	16,951
Current maturities	—	250,000
	$ 3,066,734	$ 2,188,779

On June 8, 2017, we completed a public offering of $500 million of 3.00% senior notes due 2027 and $250 million of 4.125% senior notes due 2044. The effective rate of these notes is 3.12% and 4.40%, after giving effect to the offering costs and the settlement of the associated forward starting interest rate swaps. The net proceeds (excluding the loss on the settlement of the interest rate swaps of $37 million) of approximately $753 million were used to repay our $250 million 6.35% senior unsecured notes at maturity on June 15, 2017 and for general corporate purposes, including the repayment of working capital borrowings pursuant to our commercial paper program.

On September 22, 2016, we entered into a three year, $200 million multi-draw floating-rate term loan agreement with a syndicate of three lenders. Borrowings under the term loan may be made in increments of $1.0 million or higher, may be repaid at any time during the loan period and will bear interest at a rate dependent upon our credit ratings at the time of such borrowing and based, at our election, on a base rate or LIBOR for the applicable interest period. The term loan was used to repay short-term debt and for working capital, capital expenditures and other general corporate purposes. At June 30, 2017, there was $125.0 million outstanding under the term loan.

We utilize short-term debt 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 $1.5 billion commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $1.5 billion of total working capital funding. The primary source of our funding is our commercial paper program, which is supported by a five-year unsecured $1.5 billion credit facility that expires September 25, 2021. The facility bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 1.25 percent, based on the Company's credit ratings. Additionally, the facility contains a $250 million accordion feature, which provides the opportunity to increase the total committed loan to $1.75 billion. This facility was amended in October 2016 to increase the total availability from $1.25 billion. At June 30, 2017 and September 30, 2016 a total of $258.6 million and $829.8 million was outstanding under our commercial paper program.

Additionally, we have a $25 million unsecured facility, which was renewed on April 1, 2017, and a $10 million unsecured revolving credit facility, which is used primarily to issue letters of credit. At June 30, 2017, there were no borrowings outstanding under either of these facilities; however, outstanding letters of credit reduced the total amount available to us under our $10 million unsecured revolving facility to $4.1 million.

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2017, 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.

These credit facilities and our 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, 2017. 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.

AEM had one uncommitted $25 million 364-day bilateral credit facility that was scheduled to expire on July 31, 2017 and one committed $15 million 364-day bilateral credit facility that was scheduled to expire on September 30, 2017. In connection with the sale of AEM discussed in Note 6, both facilities were terminated on January 3, 2017.

6. Divestitures and Acquisitions

Divestiture of Atmos Energy Marketing (AEM)

On October 29, 2016, we entered into a Membership Interest Purchase Agreement (the Agreement) with CenterPoint Energy Services, Inc., a subsidiary of CenterPoint Energy, Inc. (CES) to sell all of the equity interests of AEM. The transaction closed on January 3, 2017, with an effective date of January 1, 2017. CES paid a cash purchase price of $38.3 million plus working capital of $109.0 million for total cash consideration of $147.3 million. Of this amount, $7.0 million was placed into escrow and will be paid to the Company within 24 months of the closing date, net of any indemnification claims agreed upon between the two companies. We recognized a net gain of $0.03 per diluted share on the sale in the second quarter of fiscal 2017 and completed the working capital true–up during the third quarter of fiscal 2017.

The operating results of our natural gas marketing reportable segment have been reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. Accordingly, expenses related to allocable general corporate overhead and interest expense are not included in these results. The decision to report this segment as a discontinued operation was predicated, in part, on the following qualitative and quantitative factors: 1) the disposal resulted in the company becoming a fully regulated entity; 2) the fact that an entire reportable segment was disposed of and 3) the fact the disposed segment represented in excess of 30 percent of consolidated revenues over the last five fiscal years.

The tables below set forth selected financial and operational information related to assets, liabilities and operating results related to discontinued operations. Operating expenses include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income. Additionally, assets and liabilities related to our natural gas marketing operations are classified as "held for sale" on our consolidated balance sheet at September 30, 2016. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported consolidated net income.

The following tables present statement of income data related to discontinued operations:

	Three Months Ended June 30	
	2017	2016
	(In thousands)	
Operating revenues	$ —	$ 200,213
Purchased gas cost	—	184,398
Operating expenses	—	7,047
Operating income	—	8,768
Other nonoperating expense	—	(304)
Income from discontinued operations before income taxes	—	8,464
Income tax expense	—	3,414
Net income from discontinued operations	$ —	$ 5,050

	Nine Months Ended June 30	
	2017	2016
	(In thousands)	
Operating revenues	$ 303,474	$ 728,989
Purchased gas cost	277,554	698,445
Operating expenses	7,874	19,940
Operating income	18,046	10,604
Other nonoperating expense	(211)	(1,937)
Income from discontinued operations before income taxes	17,835	8,667
Income tax expense	6,841	3,495
Income from discontinued operations	10,994	5,172
Gain on sale from discontinued operations, net of tax ($10,215 and $0)	2,716	—
Net income from discontinued operations	$ 13,710	$ 5,172

The following table presents a reconciliation of the carrying amounts of major classes of assets and liabilities of our natural gas marketing's operations to total assets and liabilities classified as held for sale:

	June 30, 2017	September 30, 2016
	(In thousands)	
Assets:		
Net property, plant and equipment	$ —	$ 11,905
Accounts receivable	—	93,551
Gas stored underground	—	54,246
Other current assets	—	14,711
Goodwill	—	16,445
Deferred charges and other assets	—	435
Total assets of the disposal group classified as held for sale in the statement of financial position (1)	—	191,293
Cash	—	25,417
Other assets	—	5
Total assets of disposal group in the statement of financial position	$ —	$ 216,715
Liabilities:		
Accounts payable and accrued liabilities	$ —	$ 72,268
Other current liabilities	—	9,640
Deferred credits and other	—	316
Total liabilities of the disposal group classified as held for sale in the statement of financial position (1)	—	82,224
Intercompany note payable	—	35,000
Tax liabilities	—	15,471
Intercompany payables	—	14,139
Other liabilities	—	3,284
Total liabilities of disposal group in the statement of financial position	$ —	$ 150,118

(1) Amounts in the comparative period are classified as current and long term in the statement of financial position.

The following table presents statement of cash flow data related to discontinued operations:

	Nine Months Ended June 30	
	2017	2016
	(In thousands)	
Depreciation and amortization expense	$ 185	$ 1,743
Capital expenditures	$ —	$ 179
Noncash gain (loss) in commodity contract cash flow hedges	$ 18,744	$ (33,898)

Acquisition of EnLink Pipeline

On December 20, 2016, we executed a purchase and sale agreement to acquire the general partnership and limited partnership interests in EnLink North Texas Pipeline, LP (EnLink Pipeline) from EnLink Energy GP, LLC and EnLink Midstream Operating, LP for a cash purchase price of $85 million, plus working capital of $1.1 million.

EnLink Pipeline's primary asset was a 140–mile natural gas pipeline located on the north side of the Dallas–Fort Worth Metroplex. The $85 million purchase price has been allocated, based on fair value using observable market inputs, to the net book value of the acquired pipeline.

7. Shareholders' Equity

Shelf Registration and At-the-Market Equity Sales Program

On March 28, 2016, we filed a registration statement with the Securities and Exchange Commission (SEC) that originally permitted us to issue, from time to time, up to $2.5 billion in common stock and/or debt securities. We also filed a prospectus supplement under the registration statement relating to an at-the-market (ATM) equity distribution program under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million. During the nine months ended June 30, 2017, we sold 1,303,494 shares of common stock under our existing ATM program for $100 million and received net proceeds of $98.8 million. At June 30, 2017, approximately $1.6 billion of securities remained available for issuance under the shelf registration statement and substantially all shares have been issued under our ATM program.

Accumulated Other Comprehensive Income (Loss)

We record deferred gains (losses) in AOCI related to available-for-sale securities, interest rate 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 (loss):

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2016	$ 4,484	$ (187,524)	$ (4,982)	$ (188,022)
Other comprehensive income before reclassifications	1,485	76,602	9,847	87,934
Amounts reclassified from accumulated other comprehensive income	68	286	(4,865)	(4,511)
Net current-period other comprehensive income	1,553	76,888	4,982	83,423
June 30, 2017	$ 6,037	$ (110,636)	$ —	$ (104,599)

	Available-for-Sale Securities	Interest Rate Agreement Cash Flow Hedges	Commodity Contracts Cash Flow Hedges	Total
	(In thousands)			
September 30, 2015	$ 4,949	$ (88,842)	$ (25,437)	$ (109,330)
Other comprehensive loss before reclassifications	(1,417)	(88,345)	(8,612)	(98,374)
Amounts reclassified from accumulated other comprehensive income	(79)	260	29,290	29,471
Net current-period other comprehensive income (loss)	(1,496)	(88,085)	20,678	(68,903)
June 30, 2016	$ 3,453	$ (176,927)	$ (4,759)	$ (178,233)

The following tables detail reclassifications out of AOCI for the three and nine months ended June 30, 2017 and 2016. Amounts in parentheses below indicate decreases to net income in the statement of income:

Accumulated Other Comprehensive Income Components	Three Months Ended June 30, 2017	
	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$ (177)	Interest charges
Commodity contracts	—	Purchased gas cost
	(177)	Total before tax
	64	Tax benefit
Total reclassifications	$ (113)	Net of tax

Accumulated Other Comprehensive Income Components	Three Months Ended June 30, 2016	
	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Cash flow hedges		
Interest rate agreements	$ (137)	Interest charges
Commodity contracts	(12,347)	Purchased gas cost(1)
	(12,484)	Total before tax
	4,865	Tax benefit
Total reclassifications	$ (7,619)	Net of tax

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2017	
	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$ (107)	Operation and maintenance expense
	(107)	Total before tax
	39	Tax benefit
	$ (68)	Net of tax
Cash flow hedges		
Interest rate agreements	$ (450)	Interest charges
Commodity contracts	7,976	Purchased gas cost(1)
	7,526	Total before tax
	(2,947)	Tax expense
	$ 4,579	Net of tax
Total reclassifications	$ 4,511	Net of tax

Accumulated Other Comprehensive Income Components	Nine Months Ended June 30, 2016 — Amount Reclassified from Accumulated Other Comprehensive Income (In thousands)	Affected Line Item in the Statement of Income
Available-for-sale securities	$ 124	Operation and maintenance expense
	124	Total before tax
	(45)	Tax expense
	$ 79	Net of tax
Cash flow hedges		
Interest rate agreements	$ (410)	Interest charges
Commodity contracts	(48,015)	Purchased gas cost[1]
	(48,425)	Total before tax
	18,875	Tax benefit
	$ (29,550)	Net of tax
Total reclassifications	$ (29,471)	Net of tax

(1) Amounts are presented as part of income from discontinued operations on the condensed consolidated statements of income.

8. 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, 2017 and 2016 are presented in the following table. Most of these costs are recoverable through our tariff rates; however, a portion of these costs is capitalized into our rate base. The remaining costs are recorded as a component of operation and maintenance expense.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 5,216	$ 4,698	$ 3,109	$ 2,705
Interest cost	6,296	7,095	2,669	3,106
Expected return on assets	(6,993)	(6,881)	(1,796)	(1,566)
Amortization of transition obligation	—	—	—	21
Amortization of prior service credit	(57)	(57)	(411)	(411)
Amortization of actuarial (gain) loss	4,248	3,319	(706)	(541)
Net periodic pension cost	$ 8,710	$ 8,174	$ 2,865	$ 3,314

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$ 15,649	$ 14,093	$ 9,327	$ 8,117
Interest cost	18,890	21,284	8,009	9,318
Expected return on assets	(20,981)	(20,642)	(5,389)	(4,698)
Amortization of transition obligation	—	—	—	62
Amortization of prior service credit	(173)	(170)	(1,233)	(1,233)
Amortization of actuarial (gain) loss	12,746	9,959	(2,120)	(1,625)
Net periodic pension cost	$ 26,131	$ 24,524	$ 8,594	$ 9,941

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2017 and 2016 are as follows:

	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
Discount rate	3.73%	4.55%	3.73%	4.55%
Rate of compensation increase	3.50%	3.50%	N/A	N/A
Expected return on plan assets	7.00%	7.00%	4.45%	4.45%

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 plan as of January 1, 2017. Based on that determination, we are not required to make a minimum contribution to our defined benefit plan during fiscal 2017; however, we made a voluntary contribution of $5.0 million during the third quarter of fiscal 2017.

We contributed $9.9 million to our other post-retirement benefit plans during the nine months ended June 30, 2017. We expect to contribute a total of between $10 million and $20 million to these plans during fiscal 2017.

9. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 11 of our Fiscal 2016 Financial Statements, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2017.

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

Our 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 hubs. At June 30, 2017, we were committed to purchase 53.2 Bcf within one year, 37.6 Bcf within two to three years and 0.4 Bcf beyond three years under indexed contracts.

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, 2017, formula rate mechanisms were pending regulatory approval in our Louisiana service area, infrastructure mechanisms were pending regulatory approval in our Mississippi and Virginia service areas and rate cases were pending regulatory approval in our Colorado service area and Texas service area related to APT. These regulatory proceedings are discussed in further detail below in *Management's Discussion and Analysis — Recent Ratemaking Developments*.

10. Financial Instruments

We currently use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments and the related accounting for these financial instruments are fully described in Notes 2 and 13 of our Fiscal 2016 Financial Statements. During the nine months ended June 30, 2017, except for the change in the scope of our natural gas marketing commodity risk management activities as a result of the sale of AEM, there were no material 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 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 2016-2017 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 27 percent, or 16.2 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

Natural Gas Marketing Commodity Risk Management Activities

Our natural gas marketing segment was 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. Through December 31, 2016, we managed 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. Effective January 1, 2017, as a result of the sale of AEM, these activities were discontinued.

Due to the sale of AEM, we determined that the cash flows associated with our natural gas marketing commodity cash flow hedges were no longer probable of occurring; therefore, we discontinued hedge accounting as of December 31, 2016. As a result, we reclassified the gain in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of purchased gas cost and recognized a pre-tax gain of $10.6 million, which is included in income from discontinued operations on the condensed consolidated statement of income for the three months ended December 31, 2016.

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, 2017, we had forward starting interest rate swaps to effectively fix the Treasury yield component associated with the anticipated issuance of $450 million unsecured senior notes in fiscal 2019 at 3.78%, which we designated as a cash flow hedge at the time the swaps were executed. As of June 30, 2017, we had $41.5 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, 2017, 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, 2017, we had 18,833 MMcf of net short commodity contracts outstanding. These contracts have not been designated as hedges.

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments as of June 30, 2017 and September 30, 2016. 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	Assets	Liabilities
		(In thousands)	
June 30, 2017			
Designated As Hedges:			
Interest rate contracts	Deferred credits and other liabilities	—	(108,860)
Total		—	(108,860)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	2,960	(230)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	268	(282)
Total		3,228	(512)
Gross Financial Instruments		3,228	(109,372)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		—	—
Net Financial Instruments		3,228	(109,372)
Cash collateral		—	—
Net Assets/Liabilities from Risk Management Activities		$ 3,228	$ (109,372)

	Balance Sheet Location	Assets	Liabilities
		(In thousands)	
September 30, 2016			
Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	$ 6,612	$ (21,903)
Interest rate contracts	Other current assets / Other current liabilities	—	(68,481)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	2,178	(3,779)
Interest rate contracts	Deferred charges and other assets / Deferred credits and other liabilities	—	(198,008)
Total		8,790	(292,171)
Not Designated As Hedges:			
Commodity contracts	Other current assets / Other current liabilities	21,186	(18,812)
Commodity contracts	Deferred charges and other assets / Deferred credits and other liabilities	14,165	(12,701)
Total		35,351	(31,513)
Gross Financial Instruments		44,141	(323,684)
Gross Amounts Offset on Consolidated Balance Sheet:			
Contract netting		(39,290)	39,290
Net Financial Instruments		4,851	(284,394)
Cash collateral		6,775	43,575
Net Assets/Liabilities from Risk Management Activities		$ 11,626	$ (240,819)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our natural gas marketing segment was recorded as a component of purchased gas cost, which is included in discontinued operations on the condensed consolidated statements of income, and primarily results from differences in the location and timing of the derivative instrument and the hedged item. For the three months ended June 30, 2016, we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $13.6 million. For the nine months ended June 30, 2017 and 2016, we recognized gains arising from fair value and cash flow hedge ineffectiveness of $3.4 million and $18.1 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our natural gas marketing segment commodity contracts designated as fair value hedges and the related hedged item on the results of discontinued operations on our condensed consolidated income statement for the three and nine months ended June 30, 2017 and 2016 is presented below.

	Three Months Ended June 30		Nine Months Ended June 30	
	2017	2016	2017	2016
	(In thousands)			
Commodity contracts	$ —	$ (22,146)	$ (9,567)	$ (11,808)
Fair value adjustment for natural gas inventory designated as the hedged item	—	35,630	12,858	29,852
Total decrease in purchased gas cost reflected in income from discontinued operations	$ —	$ 13,484	$ 3,291	$ 18,044
The decrease in purchased gas cost reflected in income from discontinued operations is comprised of the following:				
Basis ineffectiveness	$ —	$ (684)	$ (597)	$ (1,490)
Timing ineffectiveness	—	14,168	3,888	19,534
	$ —	$ 13,484	$ 3,291	$ 18,044

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.

Cash Flow Hedges

The impact of our interest rate and natural gas marketing segment cash flow hedges on our condensed consolidated income statements for the three and nine months ended June 30, 2017 and 2016 is presented below.

	Three Months Ended June 30		Nine Months Ended June 30	
	2017	2016	2017	2016
	(In thousands)			
Loss reclassified from AOCI for effective portion of natural gas marketing commodity contracts	$ —	$ (12,347)	$ (2,612)	$ (48,015)
Gain arising from ineffective portion of natural gas marketing commodity contracts	—	66	111	84
Gain on discontinuance of cash flow hedging of natural gas marketing commodity contracts reclassified from AOCI	—	—	10,579	—
Total impact on purchased gas cost reflected in income from discontinued operations	—	(12,281)	8,078	(47,931)
Net loss on settled interest rate agreements reclassified from AOCI into interest expense	(177)	(137)	(450)	(410)
Total Impact from Cash Flow Hedges	$ (177)	$ (12,418)	$ 7,628	$ (48,341)

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, 2017 and 2016. 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	
	2017	2016	2017	2016
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$ (18,669)	$ (39,337)	$ 76,602	$ (88,345)
Forward commodity contracts	—	10,573	9,847	(8,612)
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	113	87	286	260
Forward commodity contracts	—	7,532	(4,865)	29,290
Total other comprehensive income (loss) from hedging, net of tax[(1)]	$ (18,556)	$ (21,145)	$ 81,870	$ (67,407)

(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 natural gas marketing segment commodity contracts were recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred losses recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2017. 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
	(In thousands)
Next twelve months	$ (1,509)
Thereafter	(40,001)
Total[(1)]	$ (41,510)

(1) Utilizing an income tax rate of 37 percent.

Financial Instruments Not Designated as Hedges

The impact of the natural gas marketing segment's financial instruments that had not been designated as hedges on our condensed consolidated income statements for the three months ended June 30, 2016 was a decrease in purchased gas cost of $1.9 million, which is included in discontinued operations on the condensed consolidated statements of income. For the nine months ended June 30, 2017 and 2016 purchased gas cost (increased) decreased by $6.8 million and $(2.8) million.

As discussed above, financial instruments used in our distribution segment are not designated as hedges. However, there is no earnings impact on our 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.

11. 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 of our Fiscal 2016 Financial Statements. During the nine months ended June 30, 2017, 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 7 of our Fiscal 2016 Financial Statements.

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, 2017 and September 30, 2016. 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	June 30, 2017
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 3,228	$ —	$ —	$ 3,228
Available-for-sale securities					
Registered investment companies	39,406	—	—	—	39,406
Bond mutual funds	15,892	—	—	—	15,892
Bonds	—	31,429	—	—	31,429
Money market funds	—	2,884	—	—	2,884
Total available-for-sale securities	55,298	34,313	—	—	89,611
Total assets	$ 55,298	$ 37,541	$ —	$ —	$ 92,839
Liabilities:					
Financial instruments	$ —	$ 109,372	$ —	$ —	$ 109,372

	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)	September 30, 2016
			(In thousands)		
Assets:					
Financial instruments	$ —	$ 44,141	$ —	$ (32,515)	$ 11,626
Hedged portion of gas stored underground	52,578	—	—	—	52,578
Available-for-sale securities					
Registered investment companies	38,677	—	—	—	38,677
Bonds	—	31,394	—	—	31,394
Money market funds	—	2,630	—	—	2,630
Total available-for-sale securities	38,677	34,024	—	—	72,701
Total assets	$ 91,255	$ 78,165	$ —	$ (32,515)	$ 136,905
Liabilities:					
Financial instruments	$ —	$ 323,684	$ —	$ (82,865)	$ 240,819

(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. As of September 30, 2016, we had $50.4 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $43.6 million was used to offset current and noncurrent risk management liabilities under master netting arrangements with the remaining $6.8 million 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, 2017				
Domestic equity mutual funds	$ 25,236	$ 7,749	$ (17)	$ 32,968
Foreign equity mutual funds	4,581	1,857	—	6,438
Bond mutual funds	15,928	—	(36)	15,892
Bonds	31,407	52	(30)	31,429
Money market funds	2,884	—	—	2,884
	$ 80,036	$ 9,658	$ (83)	$ 89,611
As of September 30, 2016				
Domestic equity mutual funds	$ 26,692	$ 6,419	$ (590)	$ 32,521
Foreign equity mutual funds	4,954	1,202	—	6,156
Bonds	31,296	108	(10)	31,394
Money market funds	2,630	—	—	2,630
	$ 65,572	$ 7,729	$ (600)	$ 72,701

At June 30, 2017 and September 30, 2016, our available-for-sale securities included $42.3 million and $41.3 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At June 30, 2017, we maintained investments in bonds that have contractual maturity dates ranging from July 2017 through December 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, 2017 and September 30, 2016:

	June 30, 2017	September 30, 2016
	(In thousands)	
Carrying Amount	$ 3,085,000	$ 2,460,000
Fair Value	$ 3,388,003	$ 2,844,990

12. Concentration of Credit Risk

Information regarding our concentration of credit risk is disclosed in Note 16 of our Fiscal 2016 Financial Statements. Except for the sale of AEM, during the nine months ended June 30, 2017, 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, 2017 and the related condensed consolidated statements of income and comprehensive income for the three and nine-month periods ended June 30, 2017 and 2016 and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2017 and 2016. 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, 2016, 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 14, 2016 except for the effects of the change in segments described in Note 3 and the discontinued operations described in Note 15, to which the date is April 12, 2017, 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, 2016, is fairly stated, in all material respects, in relation to the consolidated balance sheets from which it has been derived.

/s/ ERNST & YOUNG LLP

Dallas, Texas
August 2, 2017

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, which appears in Item 7 of Exhibit 99.1 to our Current Report on Form 8-K dated April 12, 2017.

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

The statements contained in this Quarterly Report on Form 10-Q may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit and capital 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; the availability and accessibility of contracted gas supplies, interstate pipeline and/or storage services; market risks beyond our control affecting our risk management activities, including commodity price volatility, counterparty creditworthiness or performance and interest rate risk; 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 natural gas distribution, pipeline and storage businesses; increased costs of providing health care benefits, along with pension and postretirement health care benefits and increased funding requirements; the inability to continue to hire, train and retain appropriate personnel; 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 climate changes or related additional legislation or regulation in the future; the inherent hazards and risks involved in operating our distribution and pipeline and storage businesses; the threat of cyber-attacks or acts of cyber-terrorism that could disrupt our business operations and information technology systems; natural disasters, terrorist activities or other events and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses, as well as our natural gas marketing business through December 31, 2016. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six distribution divisions, which at June 30, 2017 covered service areas located in eight states. In addition, we transport natural gas for others through our distribution and pipeline systems.

Through December 31, 2016, our natural gas marketing business provided natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers primarily in the Midwest and Southeast. We completed the sale of this business in January 2017.

We manage and review our consolidated operations through the following three reportable segments:

- The *distribution segment* is primarily comprised of our regulated natural gas distribution and related sales operations in eight states.
- The *pipeline and storage segment* is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana, which were included in our former nonregulated segment.
- The *natural gas marketing segment* is comprised of our discontinued natural gas marketing business.

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 Item 7 of Exhibit 99.1 to our Current Report on Form 8-K dated April 12, 2017 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, 2017.

Non-GAAP Financial Measure

Our operations are affected by the cost of natural gas. The cost of gas is passed through to our customers without markup and includes commodity price, transportation, storage, injection and withdrawal fees and settlements of financial instruments used to mitigate commodity price risk. These costs are reflected in the income statement as purchased gas cost. Therefore, increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe Gross Profit, a non-GAAP financial measure defined as operating revenues less purchased gas cost, is a better indicator of our financial performance than operating revenues as it provides a useful and more relevant measure to analyze our financial performance. As such, the following discussion and analysis of our financial performance will reference gross profit rather than operating revenues and purchased gas cost individually.

RESULTS OF OPERATIONS

Executive Summary

Atmos Energy strives to operate its businesses safely and reliably while delivering superior shareholder value. In recent years, we have implemented rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved rate from customer usage patterns. Additionally, we have significantly increased investments in the safety and reliability of our natural gas distribution and transmission infrastructure. This increased level of investment and timely recovery of these investments through our regulatory mechanisms has resulted in increased earnings and operating cash flows in recent years.

The pursuit of our strategy was the primary driver for our decision to sell our nonregulated natural gas marketing business and to fully exit that business. The sale was announced in October 2016 and closed in January 2017 with the receipt of $140.3 million in cash proceeds, including working capital. We recorded a net gain of $0.03 per diluted share on the sale in the second quarter of fiscal 2017. The proceeds received from the transaction were used to fund infrastructure additions and enhancements in our remaining businesses. As a result of the sale, the results of operations for the divested business have been presented as discontinued operations in the tables below:

	Three Months Ended June 30		
	2017	2016	Change
	(In thousands, except per share data)		
Distribution operations	$ 36,514	$ 30,361	$ 6,153
Pipeline and storage operations	34,294	35,782	(1,488)
Net income from continuing operations	70,808	66,143	4,665
Net income from discontinued operations	—	5,050	(5,050)
Net income	$ 70,808	$ 71,193	$ (385)
Diluted EPS from continuing operations	$ 0.67	$ 0.64	$ 0.03
Diluted EPS from discontinued operations	—	0.05	(0.05)
Consolidated diluted EPS	$ 0.67	$ 0.69	$ (0.02)

	Nine Months Ended June 30		
	2017	2016	Change
	(In thousands, except per share data)		
Distribution operations	$ 253,023	$ 219,377	$ 33,646
Pipeline and storage operations	93,835	91,315	2,520
Net income from continuing operations	346,858	310,692	36,166
Net income from discontinued operations	13,710	5,172	8,538
Net income	$ 360,568	$ 315,864	$ 44,704
Diluted EPS from continuing operations	$ 3.27	$ 3.01	$ 0.26
Diluted EPS from discontinued operations	0.13	0.05	0.08
Consolidated diluted EPS	$ 3.40	$ 3.06	$ 0.34

Net income from continuing operations increased 12 percent, compared to the prior-year period, despite weather that was 30 percent warmer than normal and 12 percent warmer than the prior-year period, primarily due to positive rate outcomes and customer growth in our distribution business. During the nine months ended June 30, 2017, our distribution segment completed 17 regulatory proceedings, resulting in an increase in annual operating income of $85.0 million and had four ratemaking efforts in progress at June 30, 2017 seeking $17.1 million of additional annual operating income. Additionally, on January 6, 2017, our Atmos Pipeline - Texas Division filed its statement of intent seeking $63.6 million, as adjusted in its rebuttal case, in additional annual operating income. On August 1, 2017, a final order was issued resulting in a $13 million increase in annual operating income. Our discontinued natural gas marketing results for the nine months ended June 30, 2017 primarily include a pre-tax gain of $10.6 million recognized in the first fiscal quarter related to the discontinuance of cash flow hedging for our natural gas marketing commodity contracts and a $2.7 million net gain on sale recognized in January 2017 upon completion of the sale.

Capital expenditures for the first nine months of fiscal 2017 were $812.1 million. Approximately 82 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 $1.1 billion and $1.25 billion for fiscal 2017. We funded our capital expenditure program primarily through operating cash flows of $745.6 million. Additionally, we issued approximately $885 million of long-term debt and $100 million of common stock during the nine month period ending June 30, 2017. The net proceeds from these issuances was primarily used to repay maturing long-term debt and to reduce short-term debt.

In addition, we acquired EnLink Pipeline in the first fiscal quarter of 2017 for an all–cash price of $86.1 million, inclusive of working capital. The acquisition of EnLink Pipeline increases the capacity on our APT intrastate pipeline to serve transportation customers in North Texas, which continues to experience significant population growth.

As a result of our sustained financial performance, cash flows and capital structure, our Board of Directors increased the quarterly dividend by 7.1 percent for fiscal 2017.

Distribution Segment

The distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states. The primary factors that impact the results of this segment 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 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 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. Gross profit in our Texas and Mississippi service areas includes 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, 2017 compared with Three Months Ended June 30, 2016

Financial and operational highlights for our distribution segment for the three months ended June 30, 2017 and 2016 are presented below.

	Three Months Ended June 30		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Operating revenues	$ 494,060	$ 424,905	$ 69,155
Purchased gas cost	197,767	147,569	50,198
Gross profit	296,293	277,336	18,957
Operating expenses	219,241	213,674	5,567
Operating income	77,052	63,662	13,390
Miscellaneous income (expense)	(62)	1,243	(1,305)
Interest charges	18,394	18,677	(283)
Income before income taxes	58,596	46,228	12,368
Income tax expense	22,082	15,867	6,215
Net income	$ 36,514	$ 30,361	$ 6,153
Consolidated distribution sales volumes — MMcf	42,974	39,040	3,934
Consolidated distribution transportation volumes — MMcf	33,307	30,416	2,891
Total consolidated distribution throughput — MMcf	76,281	69,456	6,825
Consolidated distribution average cost of gas per Mcf sold	$ 4.60	$ 3.78	$ 0.82

Income for our distribution segment increased 20 percent, primarily due to a $19.0 million increase in gross profit, partially offset with a $5.6 million increase in operating expenses. The quarter-over-quarter increase in gross profit primarily reflects:

- a $13.7 million net increase in rate adjustments, primarily in our Mid-Tex, West Texas, Louisiana and Mississippi Divisions.
- Customer growth, primarily in our Mid-Tex Division, which contributed an incremental $1.1 million.
- a $1.8 million net increase in residential and commercial consumption, primarily in our Mid-Tex Division.

The increase in operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to higher depreciation and property tax expense associated with increased capital investments, as well as higher administrative expenses.

The following table shows our operating income by distribution division, in order of total rate base, for the three months ended June 30, 2017 and 2016. The presentation of our distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30		
	2017	2016	Change
	(In thousands)		
Mid-Tex	$ 37,055	$ 33,562	$ 3,493
Kentucky/Mid-States	13,073	7,126	5,947
Louisiana	11,051	10,051	1,000
West Texas	6,639	5,659	980
Mississippi	3,437	3,916	(479)
Colorado-Kansas	3,842	3,111	731
Other	1,955	237	1,718
Total	$ 77,052	$ 63,662	$ 13,390

Nine Months Ended June 30, 2017 compared with Nine Months Ended June 30, 2016

Financial and operational highlights for our distribution segment for the nine months ended June 30, 2017 and 2016 are presented below.

	Nine Months Ended June 30		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Operating revenues	$ 2,211,257	$ 1,936,475	$ 274,782
Purchased gas cost	1,106,209	912,231	193,978
Gross profit	1,105,048	1,024,244	80,804
Operating expenses	646,299	622,100	24,199
Operating income	458,749	402,144	56,605
Miscellaneous income	334	804	(470)
Interest charges	56,437	57,481	(1,044)
Income before income taxes	402,646	345,467	57,179
Income tax expense	149,623	126,090	23,533
Net income	$ 253,023	$ 219,377	$ 33,646
Consolidated regulated distribution sales volumes — MMcf	215,158	227,664	(12,506)
Consolidated regulated distribution transportation volumes — MMcf	109,397	103,304	6,093
Total consolidated regulated distribution throughput — MMcf	324,555	330,968	(6,413)
Consolidated regulated distribution average cost of gas per Mcf sold	$ 5.14	$ 4.01	$ 1.13

Income for our distribution segment increased 15 percent, primarily due to an $80.8 million increase in gross profit, partially offset with a $24.2 million increase in operating expenses. The year-over-year increase in gross profit primarily reflects:

- a $59.0 million net increase in rate adjustments, primarily in our Mid-Tex, Louisiana and Mississippi Divisions.
- Customer growth, primarily in our Mid-Tex and Tennessee service areas, which contributed an incremental $5.4 million.
- a $3.8 million increase in revenue-related taxes in our Mid-Tex and West Texas Divisions, offset by a corresponding $3.5 million increase in the related tax expense.
- a $4.2 million increase in transportation primarily in our Kentucky/Mid-States, Mid-Tex and West Texas Divisions.
- a $2.1 million net increase in residential consumption, primarily in our Mid-Tex Division.

The increase in operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, was primarily due to an increase in employee-related costs, higher levels of line locate and pipeline integrity activities, primarily in our Mid-Tex Division, and higher depreciation and property tax expense associated with increased capital investments.

The following table shows our operating income by distribution division, in order of total rate base, for the nine months ended June 30, 2017 and 2016. The presentation of our distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2017	2016	Change
		(In thousands)	
Mid-Tex	$ 200,607	$ 181,858	$ 18,749
Kentucky/Mid-States	69,821	56,911	12,910
Louisiana	61,276	50,754	10,522
West Texas	42,590	38,793	3,797
Mississippi	41,197	40,369	828
Colorado-Kansas	33,878	31,189	2,689
Other	9,380	2,270	7,110
Total	$ 458,749	$ 402,144	$ 56,605

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 2017, we completed 17 regulatory proceedings, resulting in an $85.0 million increase in annual operating income as summarized below.

Rate Action	Annual Increase in Operating Income
	(In thousands)
Annual formula rate mechanisms	$ 84,190
Rate case filings	6
Other rate activity	784
	$ 84,980

Additionally, the following ratemaking efforts seeking $17.1 million in annual operating income were in progress as of June 30, 2017:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Louisiana	Formula Rate Mechanism	LGS(1)	6,237
Mississippi	Infrastructure Mechanism	Mississippi	7,600
Colorado-Kansas	Rate Case	Colorado	2,916
Kentucky/Mid-States	Infrastructure Mechanism	Virginia	308
			$ 17,061

(1) The proposed increase for LGS customers was implemented on July 1, 2017, subject to refund.

Annual Formula Rate Mechanisms

As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have formula rate mechanisms in our Louisiana, Mississippi and Tennessee operations and in substantially all of our Texas divisions. Additionally, we have specific infrastructure programs in substantially all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state:

Annual Formula Rate Mechanisms

State	Infrastructure Programs	Formula Rate Mechanisms
Colorado	System Safety and Integrity Rider (SSIR)	—
Kansas	Gas System Reliability Surcharge (GSRS)	—
Kentucky	Pipeline Replacement Program (PRP)	—
Louisiana	(1)	Rate Stabilization Clause (RSC)
Mississippi	System Integrity Rider (SIR)	Stable Rate Filing (SRF), Supplemental Growth Filing (SGR)
Tennessee	—	Annual Rate Mechanism (ARM)
Texas	Gas Reliability Infrastructure Program (GRIP), (1)	Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM)
Virginia	Steps to Advance Virginia Energy (SAVE)	—

(1) Infrastructure mechanisms in Texas and Louisiana allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes (Texas only), until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates.

The following annual formula rate mechanisms were approved during the nine months ended June 30, 2017:

Division	Jurisdiction	Test Year Ended	Increase in Annual Operating Income	Effective Date
			(In thousands)	
2017 Filings:				
Mid-Tex	Mid-Tex DARR [(1)]	09/30/2016	$ 9,672	06/01/2017
Mid-Tex	Mid-Tex Cities RRM	12/31/2016	36,239	06/01/2017
Kentucky/Mid-States	Tennessee ARM	05/31/2016	6,740	06/01/2017
Mid-Tex	Mid-Tex Environs	12/31/2016	1,568	05/23/2017
West Texas	West Texas Environs	12/31/2016	872	05/23/2017
West Texas	West Texas ALDC	12/31/2016	4,682	04/25/2017
Louisiana	TransLa [(2)]	09/30/2016	4,392	04/01/2017
West Texas	West Texas Cities RRM	09/30/2016	4,255	03/15/2017
Colorado-Kansas	Kansas	09/30/2016	801	02/09/2017
Mississippi	Mississippi SRF	10/31/2017	4,390	01/12/2017
Mississippi	Mississippi SIR	10/31/2017	3,334	01/01/2017
Mississippi	Mississippi SGR	10/31/2017	1,292	01/01/2017
Colorado-Kansas	Colorado SSIR	12/31/2017	1,350	01/01/2017
Kentucky/Mid-States	Kentucky PRP	09/30/2017	4,981	10/14/2016
Kentucky/Mid-States	Virginia SAVE	09/30/2017	(378)	10/01/2016
Total 2017 Filings			$ 84,190	

(1) The Company and the City of Dallas were unable to arrive at a mutually agreeable settlement; therefore the DARR rates were implemented, subject to refund, pending the outcome of an appeal filed with the Texas Railroad Commission.
(2) The Trans Louisiana RSC rates were implemented subject to refund on April 1, 2017.

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 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, 2017:

Division	State	Increase in Annual Operating Income	Effective Date
		(In thousands)	
2017 Rate Case Filings:			
Kentucky/Mid-States [1]	Virginia	$ 6	12/27/2016
Total 2017 Rate Case Filings		$ 6	

(1) The Virginia State Corporation Commission issued a final order approving a re-basing of the Company's SAVE rates into base rates and a decrease to depreciation expense. The Company had implemented rates on April 1, 2016, subject to refund, of $0.5 million.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2017:

Division	Jurisdiction	Rate Activity	Additional Annual Operating Income	Effective Date
			(In thousands)	
2017 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad-Valorem[1]	$ 784	2/1/2017
Total 2017 Other Rate Activity			$ 784	

(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.

Pipeline and Storage Segment

Our pipeline and storage segment consists of the pipeline and storage operations of our Atmos Pipeline–Texas Division (APT) and our natural gas transmission operations in Louisiana, which were previously included in our former nonregulated segment. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas producing areas of central, northern, eastern and western Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Delaware and Midland Basins of West Texas. APT provides transportation and storage services to our Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, as well as marketers and producers. As part of its pipeline operations, APT manages five underground storage facilities in Texas.

Our natural gas transmission operations in Louisiana are comprised of a proprietary 21-mile pipeline located in New Orleans, Louisiana that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements.

Our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Texas and Louisiana service areas. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation and storage 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 in Texas could influence the volumes of gas transported for shippers through our Texas pipeline system and the rates for such transportation.

The results of APT are also significantly impacted by the natural gas requirements of its local distribution company customers. Additionally, its operations may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

APT annually uses GRIP to recover capital costs incurred in the prior calendar year. However, GRIP also requires a utility to file a statement of intent at least once every five years to review its costs and expenses, including capital costs filed for recovery under GRIP. However, APT is precluded from submitting a GRIP filing until a final order has been issued on the statement of intent. Accordingly, APT has not yet submitted its annual GRIP filing for calendar year 2016. On January 6, 2017, APT filed its statement of intent seeking $63.6 million, as adjusted in its rebuttal case, in additional annual operating income. On August 1, 2017, a final order was issued resulting in a $13 million increase in annual operating income.

On December 21, 2016, the Louisiana Public Service Commission approved an annual increase of five percent to the demand fee charged by our natural gas transmission pipeline for each of the next 10 years, effective October 1, 2017. This agreement will replace the existing agreement that expires in September 2017.

Three Months Ended June 30, 2017 compared with Three Months Ended June 30, 2016

Financial and operational highlights for our pipeline and storage segment for the three months ended June 30, 2017 and 2016 are presented below.

	Three Months Ended June 30		
	2017	**2016**	**Change**
	(In thousands, unless otherwise noted)		
Mid-Tex / Affiliate transportation revenue	$ 84,594	$ 85,262	$ (668)
Third-party transportation revenue	27,369	23,877	3,492
Other revenue	5,320	4,716	604
Total operating revenues	117,283	113,855	3,428
Total purchased gas cost	1,251	(438)	1,689
Gross profit	116,032	114,293	1,739
Operating expenses	52,420	49,559	2,861
Operating income	63,612	64,734	(1,122)
Miscellaneous expense	(227)	(125)	(102)
Interest charges	10,104	9,002	1,102
Income before income taxes	53,281	55,607	(2,326)
Income tax expense	18,987	19,825	(838)
Net income	$ 34,294	$ 35,782	$ (1,488)
Gross pipeline transportation volumes — MMcf	192,543	158,758	33,785
Consolidated pipeline transportation volumes — MMcf	159,023	128,881	30,142

Net income for our pipeline and storage segment decreased four percent, primarily due to a $2.9 million increase in operating expenses, offset by a $1.7 million increase in gross profit. The increase in gross profit is primarily the result of higher through system revenue of $1.3 million, largely related to incremental throughput on the EnLink Pipeline, which was acquired in the first quarter of fiscal 2017, and higher basis spreads due to increased production in the Permian Basin. As noted above, as a result of the annual rate case, we did not file our annual GRIP filing during the second quarter of fiscal 2017, which influenced this segment's performance quarter-over-quarter.

Operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased $2.9 million, primarily due to higher depreciation expense and property taxes associated with increased capital investments and the acquisition of EnLink Pipeline.

Nine Months Ended June 30, 2017 compared with Nine Months Ended June 30, 2016

Financial and operational highlights for our pipeline and storage segment for the nine months ended June 30, 2017 and 2016 are presented below.

	Nine Months Ended June 30		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Mid-Tex / Affiliate transportation revenue	$ 251,354	$ 229,916	$ 21,438
Third-party transportation revenue	72,414	66,393	6,021
Other revenue	15,439	18,115	(2,676)
Total operating revenues	339,207	314,424	24,783
Total purchased gas cost	2,331	(72)	2,403
Gross profit	336,876	314,496	22,380
Operating expenses	159,871	143,859	16,012
Operating income	177,005	170,637	6,368
Miscellaneous expense	(784)	(894)	110
Interest charges	30,035	27,294	2,741
Income before income taxes	146,186	142,449	3,737
Income tax expense	52,351	51,134	1,217
Net income	$ 93,835	$ 91,315	$ 2,520
Gross pipeline transportation volumes — MMcf	574,556	526,532	48,024
Consolidated pipeline transportation volumes — MMcf	425,150	373,080	52,070

Net income for our pipeline and storage segment increased three percent, primarily due to a $22.4 million increase in gross profit, offset by a $16.0 million increase in operating expenses. The increase in gross profit primarily reflects a $22.1 million increase in rates from the GRIP filings approved in fiscal 2016.

Operating expenses, which includes operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, increased $16.0 million, primarily due to increased levels of pipeline maintenance and integrity activities and higher depreciation expense and property taxes associated with increased capital investments and the acquisition of EnLink Pipeline.

Natural Gas Marketing Segment

Through December 31, 2016, we were engaged in an unregulated natural gas marketing business, which was conducted by Atmos Energy Marketing (AEM). AEM's primary business was to aggregate and purchase gas supply, arrange transportation and storage logistics and ultimately deliver gas to customers at competitive prices. Additionally, AEM utilized proprietary and customer–owned transportation and storage assets to provide various services its customers requested. AEM served most of its customers under contracts generally having one to two year terms. As a result, AEM's margins arose from the types of commercial transactions it had structured with its customers and its ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it had access to serve those customers.

As more fully described in Note 6, effective January 1, 2017, we sold all of the equity interests of AEM to CenterPoint Energy Services, Inc. (CES), a subsidiary of CenterPoint Energy Inc. As a result of the sale, Atmos Energy has fully exited the nonregulated natural gas marketing business. Accordingly, these operations have been reported as discontinued operations.

Three Months Ended June 30, 2017 compared with Three Months Ended June 30, 2016

Financial and operating highlights for our natural gas marketing segment for the three months ended June 30, 2017 and 2016 are presented below.

	Three Months Ended June 30		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Operating revenues	$ —	$ 200,213	$ (200,213)
Purchased gas cost	—	184,398	(184,398)
Gross profit	—	15,815	(15,815)
Operating income	—	7,047	(7,047)
Operating income	—	8,768	(8,768)
Miscellaneous income	—	56	(56)
Interest charges	—	360	(360)
Income before income taxes	—	8,464	(8,464)
Income tax expense	—	3,414	(3,414)
Net income from discontinued operations	$ —	$ 5,050	$ (5,050)
Gross natural gas marketing delivered gas sales volumes — MMcf	—	84,415	(84,415)
Consolidated natural gas marketing delivered gas sales volumes — MMcf	—	72,742	(72,742)
Net physical position (Bcf)	—	29.4	(29.4)

Nine Months Ended June 30, 2017 compared with Nine Months Ended June 30, 2016

Financial and operating highlights for our natural gas marketing segment for the nine months ended June 30, 2017 and 2016 are presented below.

	Nine Months Ended June 30		
	2017	2016	Change
	(In thousands, unless otherwise noted)		
Operating revenues	$ 303,474	$ 728,989	$ (425,515)
Purchased gas cost	277,554	698,445	(420,891)
Gross profit	25,920	30,544	(4,624)
Operating expenses	7,874	19,940	(12,066)
Operating income	18,046	10,604	7,442
Miscellaneous income	30	171	(141)
Interest charges	241	2,108	(1,867)
Income before income taxes	17,835	8,667	9,168
Income tax expense	6,841	3,495	3,346
Income from discontinued operations	10,994	5,172	5,822
Gain on sale of discontinued operations, net of tax	2,716	—	2,716
Net income from discontinued operations	$ 13,710	$ 5,172	$ 8,538
Gross nonregulated delivered gas sales volumes — MMcf	90,223	280,588	(190,365)
Consolidated nonregulated delivered gas sales volumes — MMcf	78,646	245,702	(167,056)
Net physical position (Bcf)	—	29.4	(29.4)

The $8.5 million year-over-year increase in net income from discontinued operations primarily reflects the recognition of a net $6.6 million noncash gain from unwinding hedge accounting for certain of the natural gas marketing business's financial positions in connection with the sale of AEM. Additionally, we recognized a $2.7 million net gain on sale upon completion of the sale of AEM to CES in January 2017.

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 45 to 55 percent. We also evaluate the levels of committed borrowing capacity that we require. We currently have over $1.5 billion of capacity under our short-term facilities.

We plan to continue to fund our growth through the use of operating cash flows and debt and equity securities, while maintaining a balanced capital structure. To support our capital market activities, we have a registration statement on file with the SEC that permits us to issue a total of $2.5 billion in common stock and/or debt securities. Under the shelf registration statement, we have filed a prospectus supplement for an at-the-market (ATM) equity distribution program under which we may issue and sell, shares of our common stock, up to an aggregate offering price of $200 million.

During the first nine months of fiscal 2017, we issued 1,303,494 shares under our ATM program and received net proceeds of $98.8 million. Substantially all shares have now been issued under this program. Additionally, on June 8, 2017, we completed a public offering of $500 million of 3.00% senior unsecured notes due 2027 and $250 million of 4.125% senior unsecured notes due 2044. The net proceeds of approximately $753 million were used to repay our $250 million 6.35% senior unsecured notes at maturity on June 15, 2017 and for general corporate purposes, including the repayment of working capital borrowings pursuant to our commercial paper program. At June 30, 2017, approximately $1.6 billion of securities remain available for issuance under the shelf registration statement.

The following table presents our capitalization inclusive of short-term debt and the current portion of long-term debt as of June 30, 2017, September 30, 2016 and June 30, 2016:

	June 30, 2017		September 30, 2016		June 30, 2016	
			(In thousands, except percentages)			
Short-term debt	$ 258,573	3.6%	$ 829,811	12.3%	$ 670,466	10.2%
Long-term debt	3,066,734	42.4%	2,438,779	36.2%	2,438,699	37.1%
Shareholders' equity	3,901,710	54.0%	3,463,059	51.5%	3,466,724	52.7%
Total	$ 7,227,017	100.0%	$ 6,731,649	100.0%	$ 6,575,889	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, 2017 and 2016 are presented below.

	Nine Months Ended June 30		
	2017	2016	Change
		(In thousands)	
Total cash provided by (used in)			
Operating activities	$ 745,561	$ 629,946	$ 115,615
Investing activities	(747,355)	(783,399)	36,044
Financing activities	24,037	191,006	(166,969)
Change in cash and cash equivalents	22,243	37,553	(15,310)
Cash and cash equivalents at beginning of period	47,534	28,653	18,881
Cash and cash equivalents at end of period	$ 69,777	$ 66,206	$ 3,571

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 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, 2017, we generated cash flow of $745.6 million from operating activities compared with $629.9 million for the nine months ended June 30, 2016. The $115.6 million increase in operating cash flows reflects the positive cash effects of successful rate case outcomes achieved in fiscal 2016 and changes in working capital, primarily the recovery of deferred purchased gas costs.

Cash flows from investing activities

In executing our regulatory strategy, we target our capital spending on regulatory mechanisms that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Substantially all of our regulated jurisdictions 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 our ongoing construction program, which enables us to enhance the safety and reliability of the systems used to provide natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. Over the last three fiscal years, approximately 80 percent of our capital spending has been committed to improving the safety and reliability of our system. We anticipate our annual capital spending will be in the range of $1 billion to $1.4 billion through fiscal 2020.

For the nine months ended June 30, 2017, cash used for investing activities was $747.4 million compared to $783.4 million in the prior-year period. Capital spending increased by $22.5 million, or 2.8 percent, as a result of planned increases in our distribution segment to repair and replace vintage pipe, partially offset by a decrease in spending in our pipeline and storage segment as a result of the substantial completion of an APT project to improve the reliability of gas service to its local distribution company customers. Cash flows from investing activities also include proceeds of $140.3 million received from the sale of AEM, a portion of the proceeds received from the completion of a State of Texas use tax audit and the $86.1 million used to purchase Enlink Pipeline in the first fiscal quarter of 2017.

Cash flows from financing activities

For the nine months ended June 30, 2017, our financing activities generated $24.0 million of cash compared with $191.0 million generated in the prior-year period. The $167.0 million decrease in cash provided by financing activities is primarily due to the reduction in our short-term debt, partially offset by an increase in our long-term debt.

The following table summarizes our share issuances for the nine months ended June 30, 2017 and 2016:

	Nine Months Ended June 30	
	2017	2016
Shares issued:		
Direct Stock Purchase Plan	90,789	107,736
1998 Long-Term Incentive Plan	529,060	597,470
Retirement Savings Plan and Trust	205,972	282,578
At-the-Market (ATM) Equity Distribution Program	1,303,494	1,360,756
Total shares issued	2,129,315	2,348,540

The year-over-year decrease in the number of shares issued primarily reflects a decrease in shares issued under the Retirement Savings Plan and Trust and the 1998 Long-Term Incentive Plan.

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 $1.5 billion commercial paper program and three committed revolving credit facilities with third-party lenders that provide a total of approximately $1.5 billion of working capital funding. As of June 30, 2017, the amount available to us under our credit facilities, net of commercial paper and outstanding letters of credit, was $1.3 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 businesses and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by two rating agencies: Standard & Poor's Corporation (S&P) and Moody's Investors Service (Moody's). As of June 30, 2017, both rating agencies maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's
Senior unsecured long-term debt	A	A2
Short-term debt	A-1	P-1

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 and Aaa for Moody's. The lowest investment grade credit rating is BBB- for S&P and Baa3 for Moody's. 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, 2017. 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 9 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, 2017.

Risk Management Activities

In our distribution and pipeline and storage segments, 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. Through December 31, 2016, we managed our exposure to the risk of natural gas price changes in our natural gas marketing segment by locking 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.

The following table shows the components of the change in fair value of our financial instruments for the three and nine months ended June 30, 2017 and 2016:

	Three Months Ended June 30		Nine Months Ended June 30	
	2017	2016	2017	2016
	(In thousands)			
Fair value of contracts at beginning of period	$ (114,004)	$ (203,949)	$ (279,543)	$ (153,981)
Contracts realized/settled	37,172	1,196	48,928	1,185
Fair value of new contracts	557	2,377	(1,040)	2,434
Other changes in value	(29,869)	(62,709)	125,511	(112,723)
Fair value of contracts at end of period	(106,144)	(263,085)	(106,144)	(263,085)
Netting of cash collateral	—	39,067	—	39,067
Cash collateral and fair value of contracts at period end	$ (106,144)	$ (224,018)	$ (106,144)	$ (224,018)

The fair value of our financial instruments at June 30, 2017 is presented below by time period and fair value source:

	Fair Value of Contracts at June 30, 2017				
	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	$ 2,730	$ (108,874)	$ —	$ —	$ (106,144)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$ 2,730	$ (108,874)	$ —	$ —	$ (106,144)

Pension and Postretirement Benefits Obligations

For the nine months ended June 30, 2017 and 2016, our total net periodic pension and other benefits costs were $34.7 million and $34.5 million. A substantial portion of those costs relating to our natural gas distribution operations are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2017 costs were determined using a September 30, 2016 measurement date. As of September 30, 2016, interest and corporate bond rates were lower than the rates as of September 30, 2015. Therefore, we decreased the discount rate used to measure our fiscal 2017 net periodic cost from 4.55 percent to 3.73 percent. We maintained the expected return on plan assets of 7.00 percent in the determination of our fiscal 2017 net periodic pension cost based upon expected market returns for our targeted asset allocation. As a result of the net impact of changes in these and other assumptions, we expect our fiscal 2017 net periodic pension cost to be generally consistent with fiscal 2016.

The amount with which we fund our defined benefit plan is determined in accordance with the Pension Protection Act of 2006 (PPA) and is influenced by the funded position of the plan when the funding requirements are determined on January 1 of each year. Based upon the determination as of January 1, 2017, we are not required to make a minimum contribution to our defined benefit plan during fiscal 2017. However, in June 2017, we made a voluntary contribution of $5.0 million.

For the nine months ended June 30, 2017 we contributed $9.9 million to our postretirement medical plans. We anticipate contributing a total of between $10 million and $20 million to our postretirement plans during fiscal 2017.

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

OPERATING STATISTICS AND OTHER INFORMATION

The following tables present certain operating statistics for our distribution and pipeline and storage segments for the three and nine-month periods ended June 30, 2017 and 2016.

Distribution Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2017	2016	2017	2016
METERS IN SERVICE, end of period				
Residential	2,935,136	2,903,099	2,935,136	2,903,099
Commercial	268,734	266,435	268,734	266,435
Industrial	1,682	1,815	1,682	1,815
Public authority and other	8,301	8,377	8,301	8,377
Total meters	3,213,853	3,179,726	3,213,853	3,179,726
INVENTORY STORAGE BALANCE — Bcf	50.4	51.3	50.4	51.3
SALES VOLUMES — MMcf[1]				
Gas sales volumes				
Residential	17,137	16,407	115,568	125,334
Commercial	15,960	14,718	71,435	73,990
Industrial	8,719	6,728	22,859	22,618
Public authority and other	1,158	1,187	5,296	5,722
Total gas sales volumes	42,974	39,040	215,158	227,664
Transportation volumes	35,020	33,367	116,227	112,477
Total throughput	77,994	72,407	331,385	340,141
OPERATING REVENUES (000's)[1]				
Gas sales revenues				
Residential	$ 294,000	$ 260,634	$ 1,385,444	$ 1,240,184
Commercial	136,611	113,075	588,273	507,580
Industrial	28,150	19,766	106,167	74,167
Public authority and other	8,591	7,309	38,307	34,402
Total gas sales revenues	467,352	400,784	2,118,191	1,856,333
Transportation revenues	20,439	18,097	67,227	60,202
Other gas revenues	6,269	6,024	25,839	19,940
Total operating revenues	$ 494,060	$ 424,905	$ 2,211,257	$ 1,936,475
Average cost of gas per Mcf sold	$ 4.60	$ 3.78	$ 5.14	$ 4.01

See footnote following these tables.

Pipeline and Storage Operations Sales and Statistical Data

	Three Months Ended June 30		Nine Months Ended June 30	
	2017	2016	2017	2016
CUSTOMERS, end of period				
Industrial	92	90	92	90
Other	239	214	239	214
Total	331	304	331	304
INVENTORY STORAGE BALANCE — Bcf	1.1	2.4	1.1	2.4
PIPELINE TRANSPORTATION VOLUMES — MMcf[(1)]	192,543	158,758	574,556	526,532
OPERATING REVENUES (000's)[(1)]	$ 117,283	$ 113,855	$ 339,207	$ 314,424

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 of Exhibit 99.1 to our Current Report on Form 8-K dated April 12, 2017. During the nine months ended June 30, 2017, except for the effects of the sale of AEM on our market risk, 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, 2017 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, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

During the nine months ended June 30, 2017, there were no material changes in the status of the litigation and other matters that were disclosed in Note 11 of our Fiscal 2016 Financial Statements. 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/ CHRISTOPHER T. FORSYTHE

Christopher T. Forsythe
Senior Vice President and
Chief Financial Officer
(Duly authorized signatory)

Date: August 2, 2017

EXHIBITS INDEX
Item 6

Exhibit Number	Description	Page Number or Incorporation by Reference to
2.1	Membership Interest Purchase Agreement by and between Atmos Energy Holdings, Inc. as Seller and CenterPoint Energy Services, Inc. as Buyer, dated as of October 29, 2016	Exhibit 2.1 to Form 8-K dated October 29, 2016 (File No. 1-10042)
10	Equity Distribution Agreement, dated as of March 28, 2016, among Atmos Energy Corporation, Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC.	Exhibit 1.1 to Form 8-K dated March 28, 2016 (File No. 1-10042)
12	Computation of ratio of earnings to fixed charges	
15	Letter regarding unaudited interim financial information	
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications*	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	
101.DEF	XBRL Taxonomy Extension Definition Linkbase	
101.LAB	XBRL Taxonomy Extension Labels Linkbase	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

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

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(q) The independent auditor's annual opinion report, with any written communication from the independent auditor to the utility that indicates the existence of a material weakness in the utility's internal controls;

RESPONSE:

Please see attachment FR_16(7)(q)_Att1 for the 2016 independent auditor's report.

ATTACHMENT:

ATTACHMENT 1 - Atmos Energy Corporation, FR_16(7)(q)_Att1 - 2016 Independent Auditor Report.pdf, 2 Pages.

Respondent: Laura Gillham

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2016 and 2015, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2016. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2016, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated November 14, 2016 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 14, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2016, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Atmos Energy Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of September 30, 2016 and 2015, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2016 of Atmos Energy Corporation and our report dated November 14, 2016 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 14, 2016

FR 16(7)(r)

REQUEST:

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(r) The quarterly reports to the stockholders for the most recent five (5) quarters;

RESPONSE:

Please see the Company's response to FR 16(7)(p).

Respondent: Laura Gillham

FR 16(7)(s)

<u>REQUEST:</u>

Section 16. Applications for General Adjustments of Existing Rates.

(7) Each application requesting a general adjustment in rates supported by a fully forecasted test period shall include the following or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(s) The summary of the latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and base period depreciation rates used by major plant accounts. If the required information has been filed in another commission case, a reference to that case's number shall be sufficient;

<u>RESPONSE:</u>

The Company is not proposing changes to its depreciation rates. Please see Attachment 1 for the Kentucky Properties Depreciation Rate Study at September 30, 2014, Attachment 2 for the Kentucky Mid-States General Office Property Depreciation Rate Study at September 30, 2014, and Attachment 3 for the Shared Services Unit Depreciation Rate Study at September 30, 2014. All three studies were presented in Case No. 2015-00343.

<u>ATTACHMENTS:</u>

ATTACHMENT 1 - Atmos Energy Corporation, FR_16(7)(s)_Att1 - 2014 KY Direct Depreciation Study Report.pdf, 104 Pages.

ATTACHMENT 2 - Atmos Energy Corporation, FR_16(7)(s)_Att2 - 2014 KY Mid-States Depreciation Study Report.pdf, 46 Pages.

ATTACHMENT 3 - Atmos Energy Corporation, FR_16(7)(s)_Att3 - 2014 SSU Depreciation Study Report.pdf, 50 Pages.

Respondent: Greg Waller

ATMOS ENERGY CORPORATION

KENTUCKY PROPERTIES

DEPRECIATION RATE STUDY

As of September 30, 2014

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

ATMOS ENERGY CORPORATION
KENTUCKY PROPERTIES
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

Atmos Energy Corporation ("Atmos" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's Kentucky Properties ("Kentucky") natural gas operations depreciable assets as of fiscal year end September 30, 2014.

The existing depreciation rates were based on the straight-line method, equal life group ("ELG") procedure, and remaining-life technique and the same method, procedure and technique are retained in this study. This study recommends a decrease of $1.6 million in annual depreciation expense when compared to the depreciation rates currently in effect. Life estimates showed the following changes: 7 accounts have an increase in life; no accounts have a decrease in life, and 51 accounts remained unchanged. Net salvage showed the following changes: 4 accounts have a decrease in net salvage (more negative), 6 accounts have an increase in net salvage (more positive or less negative), and 48 accounts remained unchanged.

The depreciation study we conducted analyzed and developed depreciation recommendations at an account level resulting in annual depreciation accrual amounts and depreciation rates at that level. The depreciation study also reflects the continuation of Vintage Group Amortization for certain General Plant accounts. Appendix A demonstrates the change in depreciation expense.

ATMOS ENERGY CORPORATION
KENTUCKY PROPERTIES
DEPRECIATION RATE STUDY
As of September 30, 2014
Table of Contents

PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable property as recorded on Atmos' books at September 30, 2014. The account based depreciation rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of Atmos' property on a straight-line basis. Non-depreciable property and property which is amortized such as intangible assets were excluded from this study.

Atmos Energy provides local gas distribution service to over 174,000 customers in Kentucky. Its assets currently consist of various storage, transmission, and distribution plant, including approximately 2,484 miles of steel and 1,437 miles of plastic gas distribution mains, located across the service area. It has a number of receipt points or city gates, throughout the system where gas enters the distribution system and is then delivered to customers for burner tip consumption.

STUDY RESULTS

The existing and current study of annual depreciation expense results from the use of Iowa Curve dispersion patterns with the straight-line method, equal life group ("ELG") procedure and remaining-life technique, and consideration of net salvage in the development of the study recommended depreciation rates. Detailed information for each of these factors will follow in this report.

Overall depreciation rates for Kentucky depreciable property are shown in Appendix A. The recommended rates translate into an annual depreciation accrual of approximately $14.7 million based on Kentucky's depreciable investment at September 30, 2014. The annual equivalent depreciation expense calculated by the same method using the currently approved rates was $16.4 million. The primary driver for the decrease in the annual depreciation expense when compared to the existing is related to the Distribution Plant Function.

Consistent with the prior study and FERC Rule AR-15, this depreciation study continues the use of Vintaged Group Amortization in Accounts 391 through 399, excluding 392, 396, and 397.05. This process provides for the amortization of general plant with a separate amortization to allocate any deficit or excess reserves. This approach provides for the timely retirement of assets, at the end of the amortized life property will be retired from the books and simplifies accounting for general property.

Appendix A presents a comparison of the composite existing rates versus the recommended study rates. Appendix B presents the development of the depreciation rates and annual accruals. Appendix C presents the mortality and net salvage parameters by account. Appendix D shows net salvage history by plant account.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

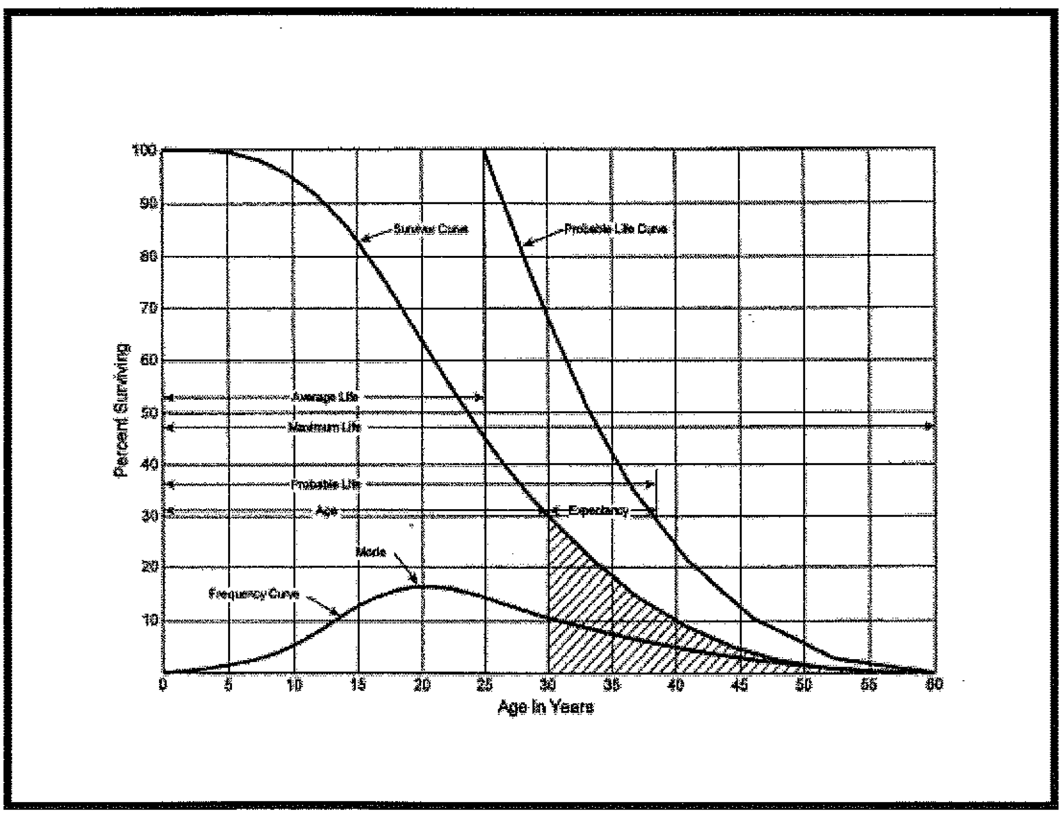
Basis of Depreciation Estimates

The straight-line, equal life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset, less allocated depreciation reserve, less estimated net salvage, by its respective equal life group remaining lives. The resulting annual accrual amounts of all depreciable property within an account were accumulated, and the total was divided by the original cost of assets in the account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual depreciation rates are shown in Appendix B and in the study workpapers.

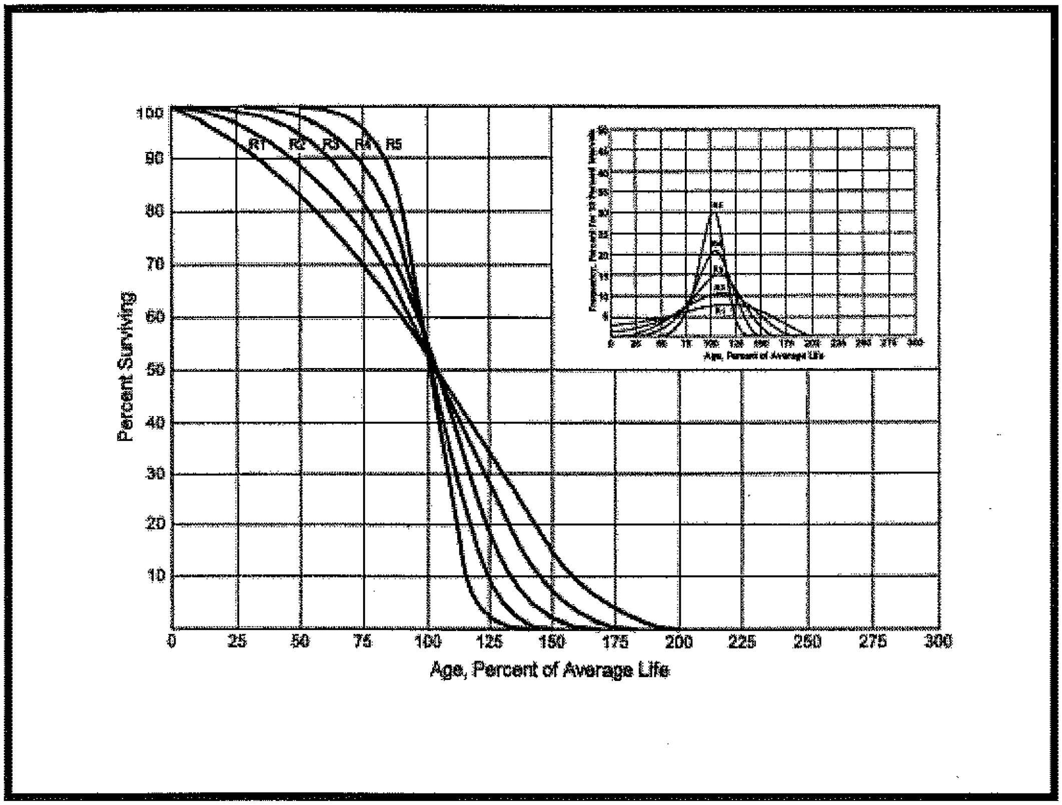
A variety of life estimation approaches were incorporated into the life analyses. Both Simulated Plant Record (SPR) analysis and Actuarial Analysis are commonly used mortality analysis techniques for gas utility property. Historically, Atmos has used SPR analysis to evaluate lives of most asset groups. The SPR balances approach was used with each account within a function where sufficient activity occurred within the account. Where vintage information is available, actuarial analysis was performed. For the accounts using actuarial analysis experience bands varied depending on the amount of data. Judgment was used to a greater or lesser degree on all accounts. Each approach used in this study is more fully described in a later section.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of "R" moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Consistent with the prior study some accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. Matching data in observed life tables for each experience and placement band to an Iowa Curve requires visual examination. As stated in Depreciation Systems by Wolf and Fitch, "the analyst must decide which points or sections of the curve should be given the most weight. Points at the end of the curve are often based on fewer exposures and may be given less weight than those points based on larger samples" (page 46). Some analysts chose to use mathematical fitting as a tool to narrow the population of curves using a least squares technique. Use of the least squares approach does not imply a statistical validity, however, because the underlying data does not meet criteria for independence between vintages and the same average price for property units through time. Thus, Depreciation Systems cautions, "... the results of mathematical fitting should be checked visually and the final determination of best fit made by the analyst" (page 48). This study uses the visual matching approach to match Iowa Curves, since mathematical fitting produces theoretically possible curve matches. Visual examination and experienced judgment allow the depreciation professional to make the final determination as to the best curve type.

Detailed information for each account is shown later in this study and in workpapers.

Simulated Plant Record Procedure ("SPR")

The SPR - Balances approach is one of the commonly accepted approaches to analyze mortality characteristics of utility property. SPR was applied to all accounts due to the unavailability of sufficient vintaged transactional data. In this method, an Iowa Curve and average service life are selected as a starting point of the analysis and its survivor factors are applied to the actual annual additions to give a sequence of annual balance totals. These simulated balances are compared with the actual balances by using both graphical and statistical analysis. Through multiple comparisons, the mortality characteristics (as defined by an average life and Iowa Curve) that are the best match to the property in the account can be found.
The Conformance Index (CI) is one measure used to evaluate SPR analyses. CIs are also used to evaluate the "goodness of fit" between the actual data and the Iowa Curve being referenced. The sum of squares difference (SSD) is a summation of the difference between the calculated balances and the actual balances for the band or test year being analyzed. This difference is squared and then summed to arrive at the SSD, where n is the number of years in the test band.

$$SSD = \sum_1^n (Calculated\ Balance_i - Observed\ Balance_i)^2$$

This calculation can then be used to develop other calculations, which the analyst feels might give a better indication for the "goodness of fit" for the representative curve under consideration. The residual measure (RM) is the square root of the average squared differences as developed above. The residual measure is calculated as follows:

$$RM = \sqrt{(\frac{SSD}{n})}$$

The conformance index (CI) is developed from the residual measure and the average observed plant balances for the band or test year being analyzed. The calculation of conformance index is shown below:

$$CI = \frac{\sum_1^n Balances_i / n}{RM}$$

The retirement experience index (REI) gives an indication of the maturity of the account and is the percent of the property retired from the oldest vintage in the band at the end of the test year. Retirement indices range from 0 percent to 100 percent and a REI of 100 percent indicates that a complete curve was used. A retirement index less than 100 percent indicates that the survivor curve was truncated at that point. The originator of the SPR method, Alex Bauhan, suggests ranges of value for the CI and REI. The relationship for CI proposed by Bauhan is shown below[1]:

CI	Value
Over 75	Excellent
50 to 75	Good
25 to 50	Fair
Under 25	Poor

1 Public Utility Depreciation Practices, p. 96.

The relationship for REI proposed by Bauhan[2] is shown below:

REI	Value
Over 75	Excellent
50 to 75	Good
33 to 50	Fair
17 to 33	Poor
17 and below	Valueless

Depreciation analysts have used these measures in analyzing SPR results for nearly 60 years, since the SPR method was developed. Both the CI and REI statistics provide the analyst with important information with which to make a comparison between a band of simulated or calculated balances and the observed or actual balances in the account being studied. It is important to understand that observing the pattern of best-fitting curves over various bands, as well as considering other company and asset-specific information, is important in the ultimate decision for the most appropriate live and curve combination that will reflect future retirements of each account.

Statistics are useful in analyzing mortality characteristics of accounts, as well as determining a range of service lives to be analyzed using the detailed graphical method. However, these statistics boil all the information down to one, or at most, a few numbers for comparison. Visual matching through comparison between actual and calculated balances expands the analysis by permitting the analyst to view many points of data at a time. The goodness of fit should be visually compared to plots of other Iowa Curve dispersions and average lives for the selection of the appropriate curve and life. Detailed information for each account is shown later in this study and in workpapers.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and

2 Public Utility Depreciation Practices, p. 97.

procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. In these cases, it is rare for one factor to individually have a, substantial impact on the analysis. However, individual factors may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing upon which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for the Storage, Transmission, Distribution and General accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the SPR balance methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Equal Life Group Depreciation

Atmos agreed that the continued use of the ELG depreciation procedure was appropriate. In addition to being approved by this Commission for the Company's currently authorized rates, the Railroad Commission of Texas has repeatedly approved the use of ELG for Atmos and other Companies. This study uses the ELG depreciation procedure to group the assets within each account. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ELG groups are defined by their respective account dispersion, life, and net salvage estimates. A straight-line rate for each ELG group is computed and accumulated across each vintage. The resulting rate for each ELG group is designed to recover all retirements less net salvage as each vintage retires. The ELG procedure recovers net book cost over the life of each ELG group rather than averaging many components. It also closely matches the concept of component or item accounting found in all accounting textbooks.

Theoretical Depreciation Reserve

The Company's book depreciation reserves were reallocated within each function by plant account based on the theoretical reserves for each account. This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The equal life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the vintage is retired. Estimated average service lives and dispersion determine the amount within each equal life group. The equal life group-remaining-life theoretical reserve ratio (RRELG) is calculated as:

$$RRELG = 1 - \frac{(ELG\ Remaining\ Life)}{(ELG\ Life)} * (1 - Net\ Salvage\ Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documenting the corresponding recommendations.

During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Considerations Section of this study. Also as part of the Phase I data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis section, the salvage analysis section, and also in workpapers.

Phase 2 was where the SPR analysis was performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in phase 2 to develop observed life tables for life analysis. These tables were visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information was then carried forward into phase 3 for the evaluation process.

Phase 3 was the evaluation process which synthesized analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from phase 2 was further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in phase 1. Phases 2 and 3 allowed the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in the final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[3] documents the steps used in conducting this study. <u>Depreciation Systems,</u> page 289 documents the same basic processes in performing a depreciation study which are: Statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, write logic supporting forecasts and estimation, and write final report.

[3] Public Utility Finance & Accounting, A Reader

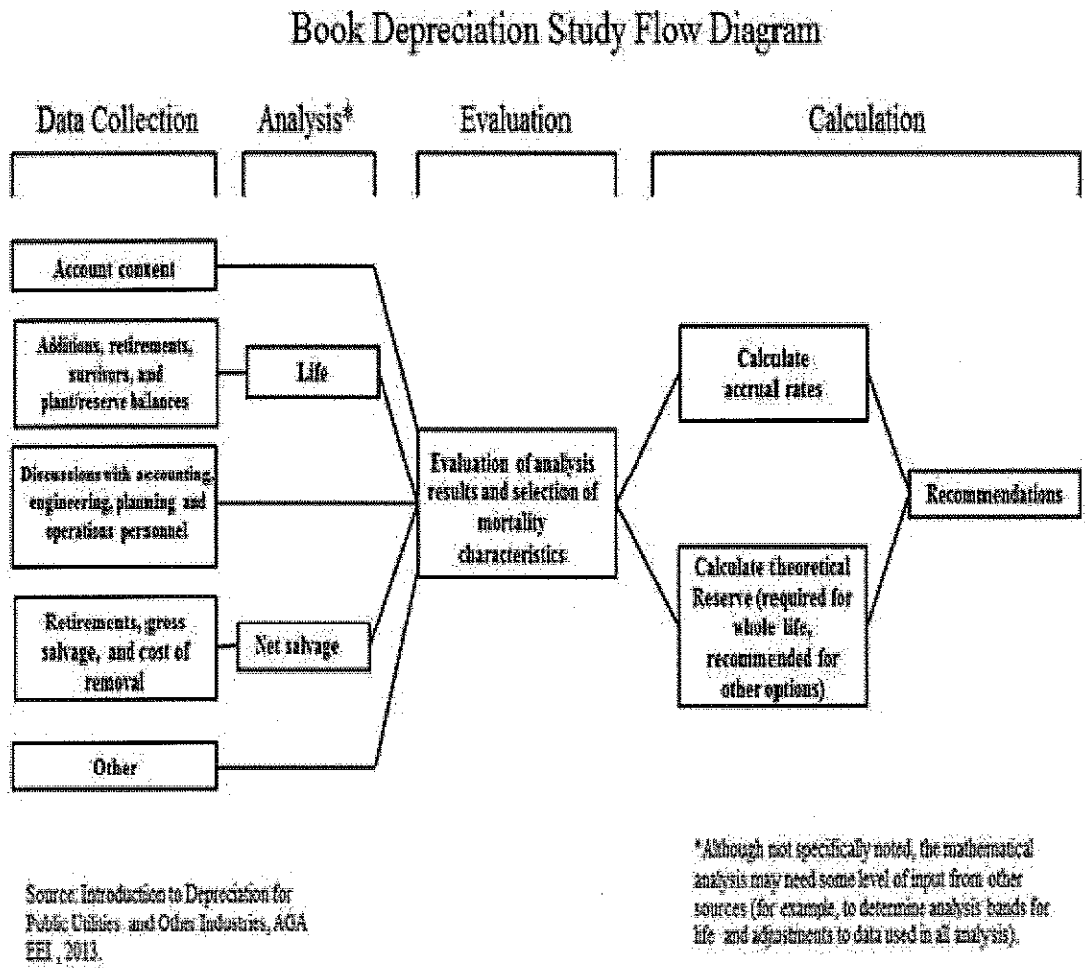


Figure 1

KENTUCKY DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable accounts of the Company were calculated by the straight line, equal life group, remaining life system. With this approach, remaining lives were calculated according to standard ELG group expectancy techniques, using the Iowa Survivor Curves noted in the calculation. For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the average remaining life to yield the annual depreciation expense. These calculations are shown in Appendix B.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using either the retirement rate actuarial or the SPR methods. After establishment of appropriate average service lives and retirement dispersion, remaining life was computed for each account. Theoretical depreciation reserve with zero net salvage was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the General Discussion section. The difference between plant balance and theoretical reserve was then spread over the ELG depreciation accruals. Remaining life is shown for each account in Appendix B.

Calculation Process

Annual depreciation expense amounts for all accounts were calculated by the straight line, remaining life procedure.

In a whole life representation, the annual accrual rate is computed by the following equation,

$$\text{Annual Accrual Rate} = \frac{(100\% - \text{Net Salvage Percent})}{\text{Average Service Life}}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight line, remaining life, equal life group system using Iowa Curves, composite remaining lives were calculated according to standard broad group expectancy techniques, noted in the formula below:

$$\text{Composite Remaining Life} = \frac{\sum \text{Original Cost} - \text{Theoretical Reserve}}{\sum \text{Whole Life Annual Accrual}}$$

For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the composite remaining life to yield the annual depreciation expense as noted in this equation.

$$\text{Annual Depreciation Expense} = \frac{\text{Original Cost} - \text{Book Reserve} - (\text{Original Cost}) * (1 - \text{Net Salvage \%})}{\text{Composite Remaining Life}}$$

Where the net salvage percent represents future net salvage.

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$\text{Annual Depreciation Rate} = \frac{\sum \text{Annual Depreciation Expense}}{\sum \text{Original Cost}}$$

These calculations are shown in Appendix B. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in workpapers. Book depreciation reserves were allocated from a functional level to individual accounts and the theoretical reserve computation was used to compute a composite remaining life for each account.

Life Analysis

The simulated plant record method SPR semi-actuarial analysis method was applied to most accounts for Kentucky. For each account where used, a simulated plant record method analysis was performed at intervals for the overall band and at various (usually 10 and/or 5-year) intervals within the overall balance period. In addition to reviewing the SPR analysis for each band and account, where possible, a graphical comparison between actual and simulated balances was performed.

The retirement rate actuarial analysis method was applied to those accounts where vintage retirement detail is available. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Survivor Curves to obtain the most appropriate match. The observed life table, a selected placement and experience bands, is shown in Appendix C. The remainder of placement and experience band analyses performed is contained in the workpapers.

For each account on the overall band (i.e. placement from earliest vintage year through 2014 and experience band from earliest available experience year through 2014, most recently approved survivor curves were used as a starting point. Then using the same life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (i.e. L, S. or R) as an obviously better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. Generally, the goal of visual matching was to minimize the differential between the observed life table and Iowa curve in top and mid-range of the plots. When adequate activity is present a graph of the observed life table versus the proposed life and curve is provided for each account where the actuarial life analysis was used.

These results are used in conjunction with all other factors that may influence asset lives.

Storage Plant – FERC Accounts 350.20 – 356.00

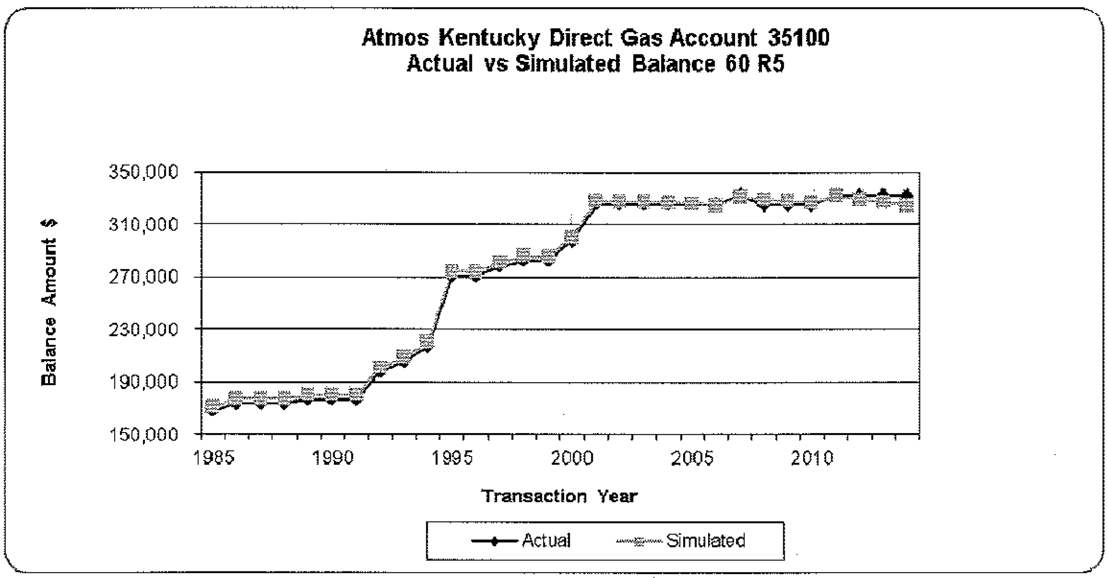
There are 5 storage fields with old gas wells. There are approximately 55 wells between the 5 fields. One well, Bon Harbor was retired (around 2009-2010).

Account 350.20 Rights-of-Way (70 R5)

This account includes the cost of rights of way used in connection with storage plant operations. There is approximately $5 thousand in this account. The existing life is 50 R5. This study recommends moving to a 70 year life and R5 dispersion.

Account 351.00-351.04 Structures & Improvements, Compressor Station Equipment, Measuring & Regulating Stations, and Other Structures (60 R5)

These accounts include the cost of structures and improvements, compressor station equipment, measuring and regulating stations, fencing and other structures used in connection with storage plant operations. There is approximately $331 thousand in total for these accounts. The accounts were analyzed together but for rate calculation purposes each account depreciation rate has been calculated separately. Based upon the analysis and discussions with Company personnel, this study recommends retaining the 60 R5. A comparison of actual versus simulated balances is shown below for the 60 R5.



Account 351.00 Structures & Improvements (60 R5)

This account includes the cost of structures and improvements used in connection with storage plant operations. There is approximately $18 thousand in this account. The existing life is 60 R5. Based on the combined SPR analysis as described above, retaining the 60 year life and R5 dispersion is recommended. See graph of the combined account actual versus simulated balances shown above.

Account 351.02 Compressor Station Equipment (60 R5)

This account includes the cost of compressor station equipment used in connection with storage plant operations. There is approximately $153 thousand in this account. The existing life is 60 R5. Retention of the 60 year life and R5 dispersion is recommended. See graph of the combined account actual versus simulated balances shown above.

Account 351.03 Measuring and Regulating Station (60 R5)

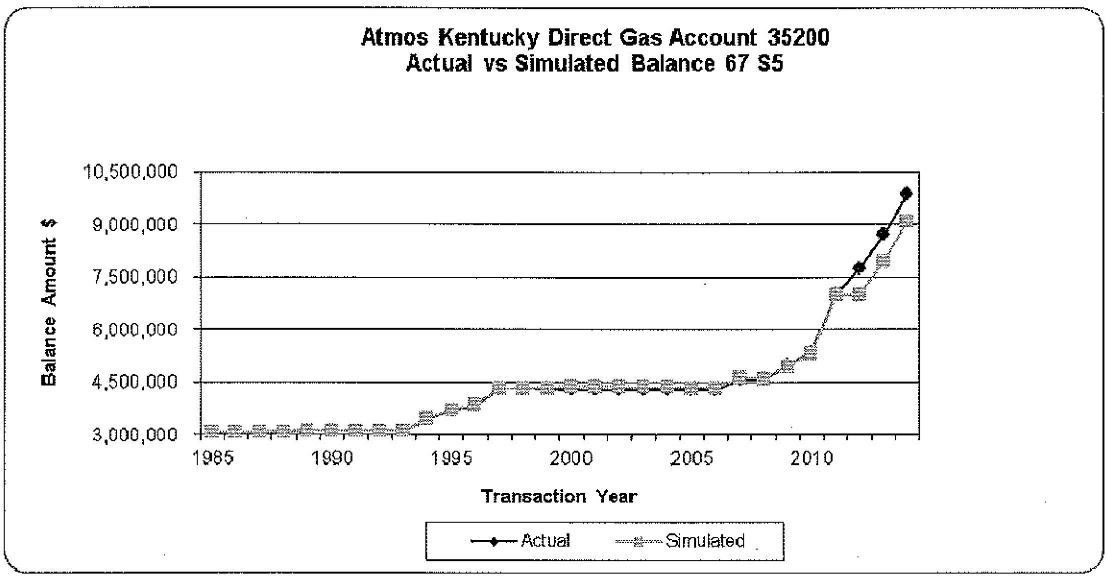
This account life analysis was combined with all other 351 accounts. There is approximately $23 thousand in this account. The existing life is 60 R5. Retention of the 60 year life and R5 dispersion is recommended. See graph of the combined account actual versus simulated balances shown above.

Account 351.04 Other Structures (60 R5)

This account includes the cost of other structures used in connection with storage plant operations. There is approximately $137 thousand in this account. The existing life is 60 R5. Retention of the 60 year life and R5 dispersion is recommended. See graph of the combined account actual versus simulated balances shown above.

Accounts 352.00, 352.01, 352.02 Wells, Well Construction, and Well Equipment (67 S5)

These accounts include the cost of wells, well construction, and well equipment used in connection with storage plant operations. There is approximately $8 million total for the accounts combined in this account. The existing life is 67 S5. There are approximately 55 wells spread across 5 storage fields. The accounts were analyzed together but for rate calculation purposes, the depreciation rate for each account has been calculated separately. Based upon the analysis and discussions with Company personnel, this study recommends retaining the 67 S5. A comparison of actual versus simulated balances is shown below for the 67 S5.



Account 352.03 Cushion Gas (50 SQ)

This account includes the cost of cushion gas used in connection with storage plant operations. There is approximately $1.7 million in this account. The existing life is 50 SQ and is retained in this study. No graph is provided.

Account 352.10 Storage Leaseholds (67 S5)

This account includes the cost of storage leaseholds used in connection with storage plant operations. There is approximately $178 thousand in this account. The existing life is 67 S5. Consistent with the life of the underlying assets, wells, this study recommends retaining the 67 year life and S5 dispersion. No graph is provided.

Account 352.11 Storage Rights (67 S5)

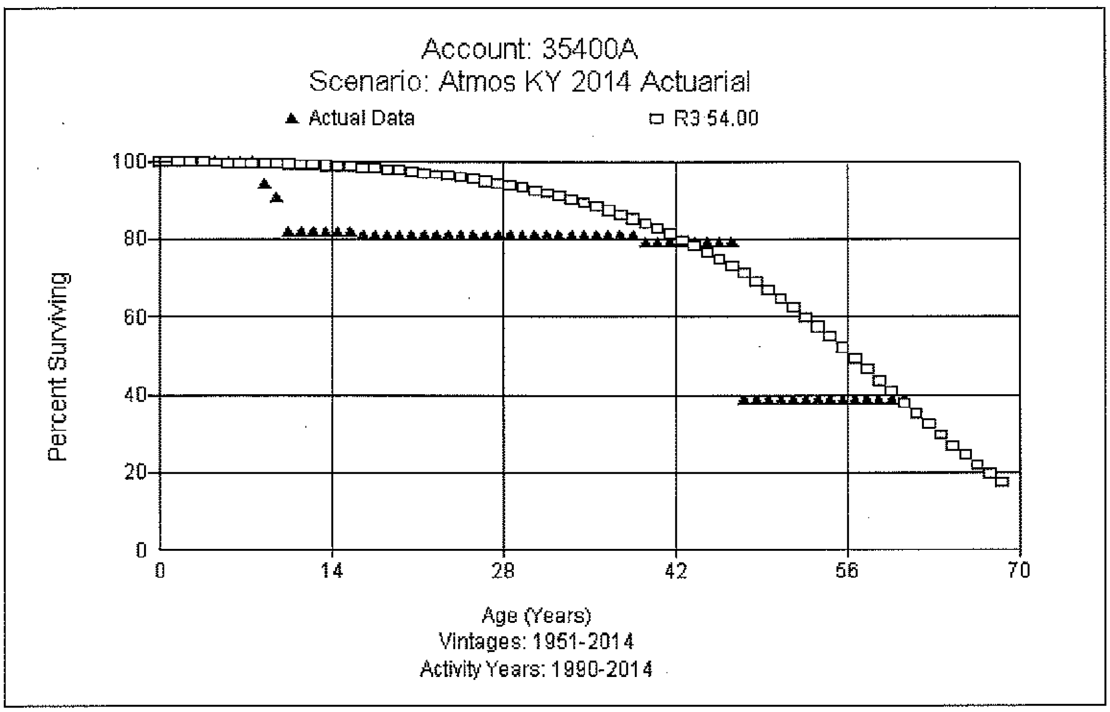
This account includes the cost of storage rights used in connection with storage plant operations. There is approximately $55 thousand in this account. The existing life is 67 S5. Consistent with the life of the underlying assets, wells, this study recommends retaining the 67 year life and S5 dispersion. No graph is provided.

Account 353.01 & 353.02 Storage Field and Tributary Lines (60 S1)

These accounts include the cost of field and tributary lines used in connection with storage plant operations. There is approximately $388 thousand in this account. The existing life is 50 S1. The current average age of investment is approximately 46 years. This study recommends increasing the life to 60 years while retaining the S1 dispersion. No graph is provided.

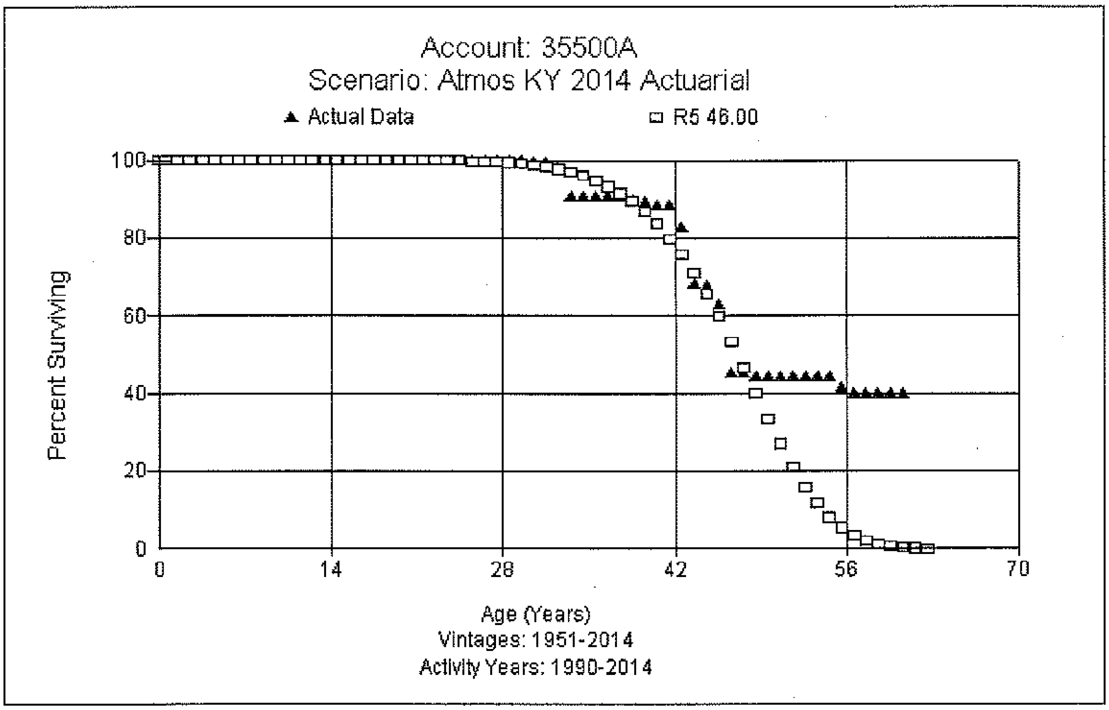
Account 354.00 Compressor Station Equipment (54 R3)

This account includes the cost of compressor station equipment used in connection with storage plant operations. There is approximately $923 thousand in this account. The existing life is 51 R3. The current average age of investment is 21 years. Different experience bands yield different age indications. The more recent bands indicate a much lower life than what would be expected for these assets. Based on a full placement (1951-2014) and a mid-experience band (1990-2014), a slightly longer life and steeper dispersion than existing is indicated, which is more consistent with the life expectations for these assets. Based on the fuller band, this study recommends increasing the life slightly to 54 years and maintaining the R3 dispersion. A graph of the observed life table and recommendation is shown below for the 54 R3.



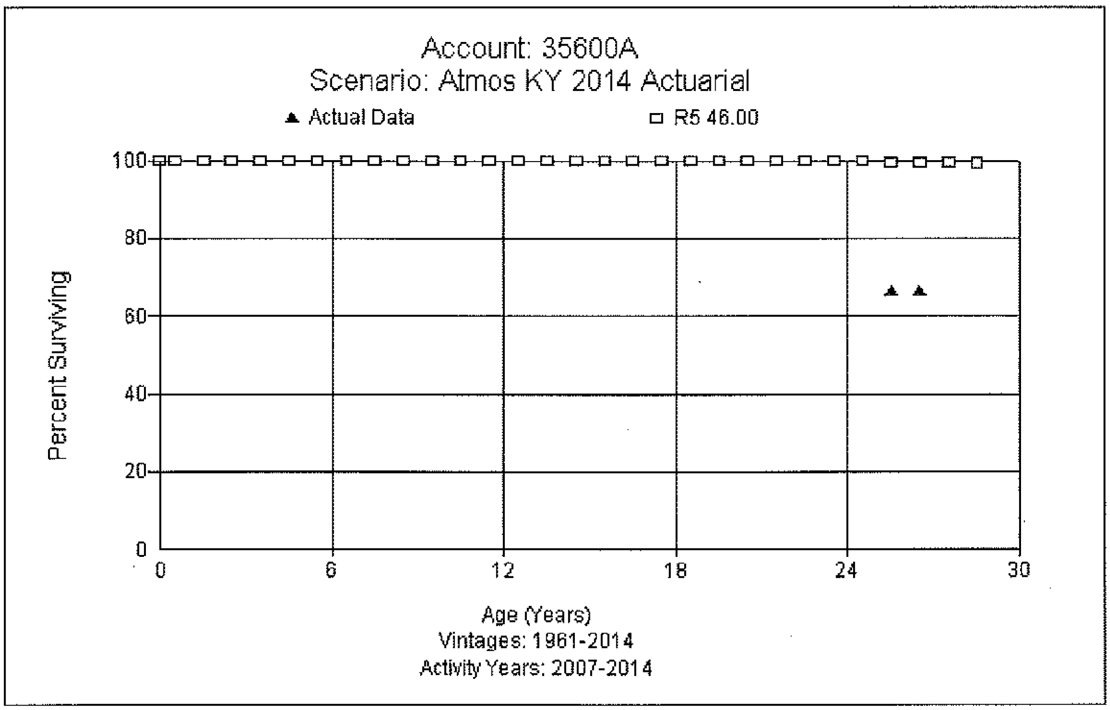
Account 355.00 Measuring and Regulating (46 R5)

This account includes the cost of measuring and regulating equipment used in connection with storage plant operations. There is approximately $241 thousand in this account. The existing life is 45 R5. The actuarial life analysis supports Company personnel statements that lives range between 40-50 years. Based on a full placement (1951-2014) and experience band (1990-2014), this study recommends increasing the life to 46 years and maintaining the R5 dispersion. A graph of the observed life table and recommendation is shown below for the 46 R5.



Account 356.00 Purification Equipment (46 R5)

This account includes the cost of purification equipment and currently includes 5 dehydrator plants, tanks, and piping used in connection with storage plant operations. There is approximately $415 thousand in this account. The existing life is 46 R5. Both the actuarial analysis and discussions with Company personnel indicated a longer life than the existing 30 years is expected. Company planned and retired 2 dehydrator plants that are approaching 50 years. The average age of retirements is 41 years. Based on the analysis and company input, this study recommends retaining the 46 year life and R5 dispersion. A graph of the observed life table and recommendation is shown below for the 46 R5.



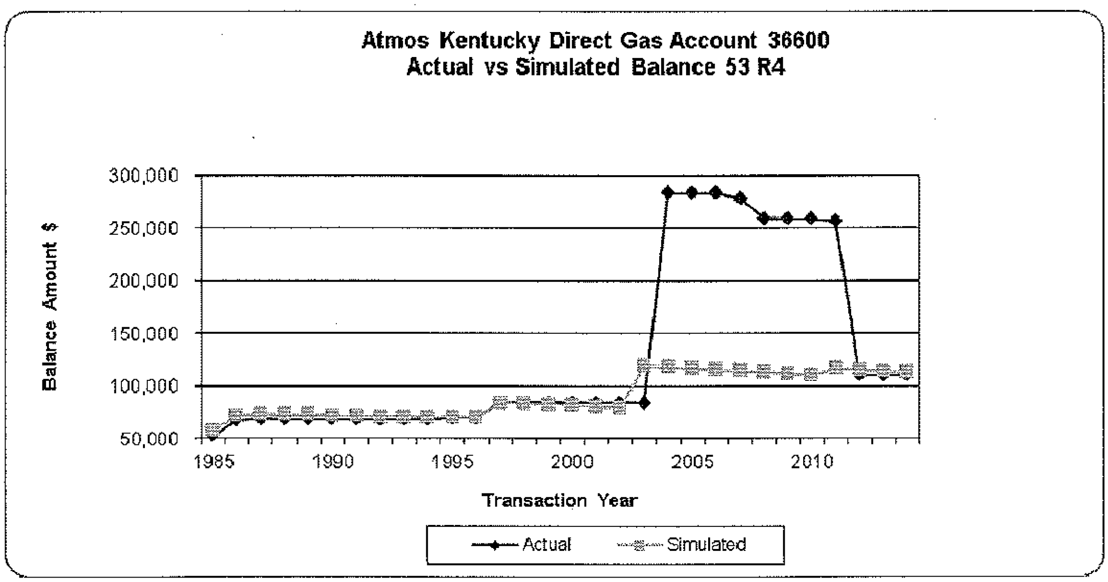
Transmission Plant – FERC Accounts 365.20 – 369.01

Account 365.20 Rights-of-Way (70 R5)

This account includes the cost of rights of way used in connection with transmission operations. There is approximately $868 thousand in this account. The existing life is 55 R5. This study recommends moving to a 70 year life and R5 dispersion. No graph is provided.

Account 366.02 & 366.03 Meas. & Reg. Station Structures & Other Structures (53 R4)

These accounts include the cost of measuring and regulating station structures and other structures used in connection with transmission operations. There is approximately $110 thousand total for the accounts combined in this account. The existing life is 53 R4. The current average age of investment is 25 years. Based on the combined SPR analysis, best fits were indicated with life ranging from 53 to 57 years. Discussions with Company personnel indicated assets are generally small metal buildings with fencing that could last around 50 years. Based on the analysis indications, this study recommends retaining the 53 year life and R4 dispersion. A comparison of actual versus simulated balances is shown below for the 53 R4.

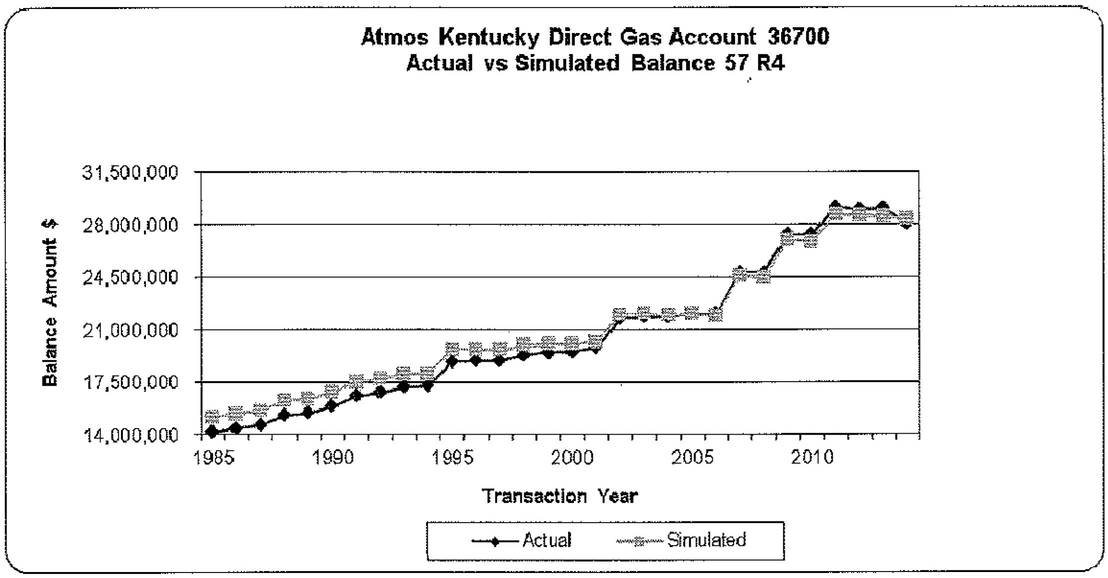


Account 367.00 Mains – Cathodic Protection (20 SQ)

This account includes the cost of cathodic protection for mains such as anodes, rectifiers, leak clamps, and other related equipment used in connection with transmission operations. There is approximately $186 thousand in this account. The existing life is 20 SQ. Discussions with Company personnel indicated the assets have a life range of 18 to 25 years. This study recommends retaining the 20 year life and the SQ dispersion to reflect the actual expected life of the anodes, rectifiers, and leak clamps that are installed with the mains but have a much lower life expectancy and no current mechanism to properly record retirements. No graph is provided.

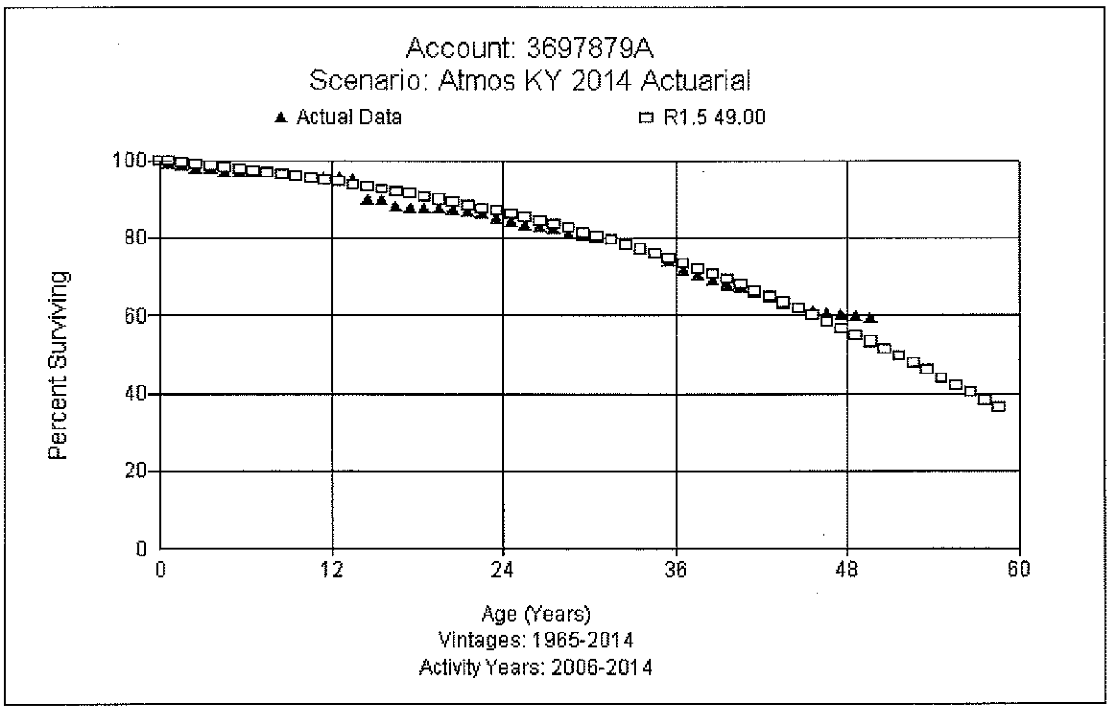
Account 367.01 Mains Steel (57 R4)

This account includes the cost of steel mains used in connection with transmission operations. There is approximately $28 million in this account. The existing life is 57 R4. Any new steel put in the ground now will be high pressure steel pipe classified as distribution. Slightly less than 25% of the pipe, in transmission, will be replaced and moved to distribution under the PRP program. Based upon the SPR analysis best fit indications the life remains close to the existing. This study recommends retention of the existing 57 R4. A comparison of actual versus simulated balances is shown below for the 57 R4.



Account 369.00 & 369.01 Measuring and Reg. Station (49 R1.5)

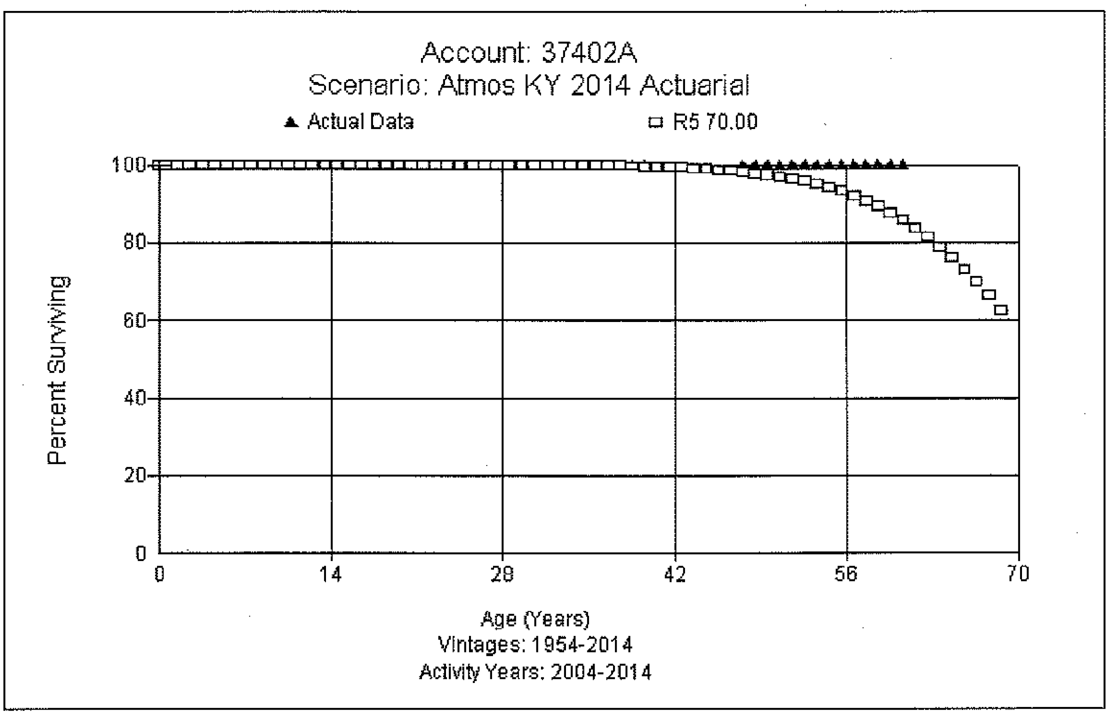
These accounts include the cost of measuring and regulating station equipment used in connection with transmission operations. There is approximately $2.9 million total for the accounts combined in this account. The existing life is 49 R2. The current average age of the investment is 24 years. The combined analysis of Measuring & Regulating Equipment for Transmission and Distribution functions indicated the 49 R1.5 to be a good fit across the bands. Company personnel indicated in discussions that equipment has changed over the years from lives of 60-70 years to 40-50 years. Some newer generations are more technology driven and are expected to have a 30-40 year life. Giving consideration to the various generations still in service, this study recommends maintaining the life of 49 years and moving to the R1.5 dispersion. As more of the older assets are retired and replaced, the life is expected to decline. A graph of the combined accounts observed life table and recommendation is shown below for the 49 R1.5.



Distribution Plant – FERC Accounts 374.02-385

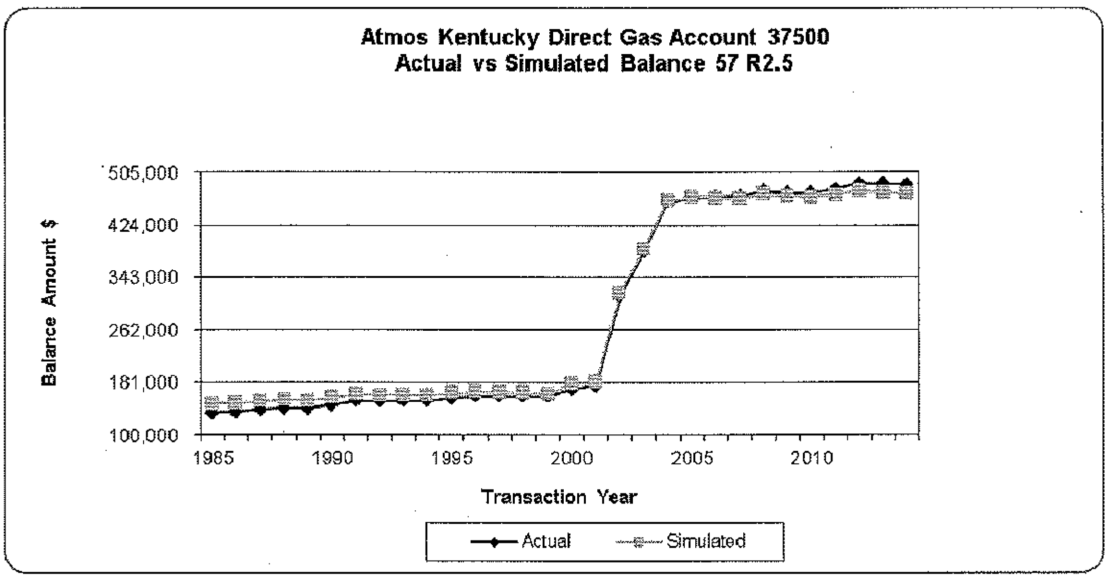
Account 374.02 Land Rights (70 R5)

This account includes the cost of land rights used in connection with distribution operations. There is approximately $253 thousand in this account. The existing life is 60 R5. This study recommends increasing life to 70 years based on judgment, while retaining the R5 dispersion. A graph of the account observed life table and recommendation is shown below for the R5 70.



Account 375.00, 375.01, 375.02, & 375.03 Structures and Improvements (57 R2.5)

These accounts include the cost of border station and regulating station structures, fences, and other miscellaneous related assets used in connection with distribution operations. There is approximately $487 thousand total for the accounts combined in this account. The existing life is 57 R2.5. There have been no recent retirements recorded. This study recommends retaining the 57 year life and the R2.5 dispersion based on the statistical analysis and judgment. A comparison of actual versus simulated balances is shown below for the 57 R2.5.

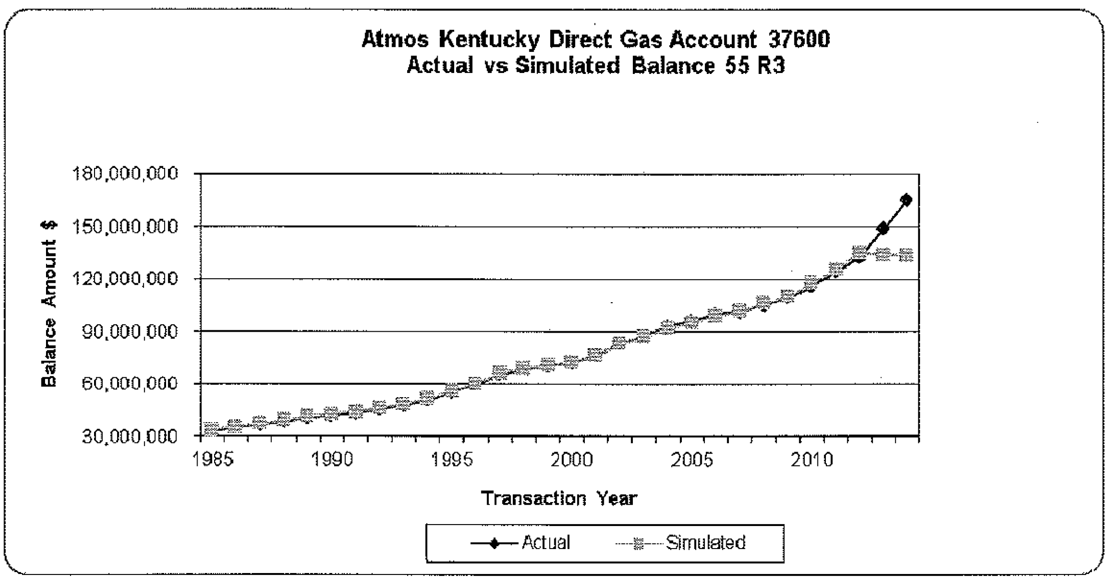


Account 376.00 Mains - Cathodic Protected (20 SQ)

This account includes the cost of anodes, rectifiers and leak clamps for distribution mains. There is approximately $21 million in this account. The existing life is the 20 SQ dispersion pattern based on the composite 376 account. This study recommends retaining the 20 year life with the SQ dispersion to reflect the actual expected life of the anodes, rectifiers, and leak clamps that are installed with the mains but have a much lower life expectancy and no current mechanism to properly record retirements. No graph is provided.

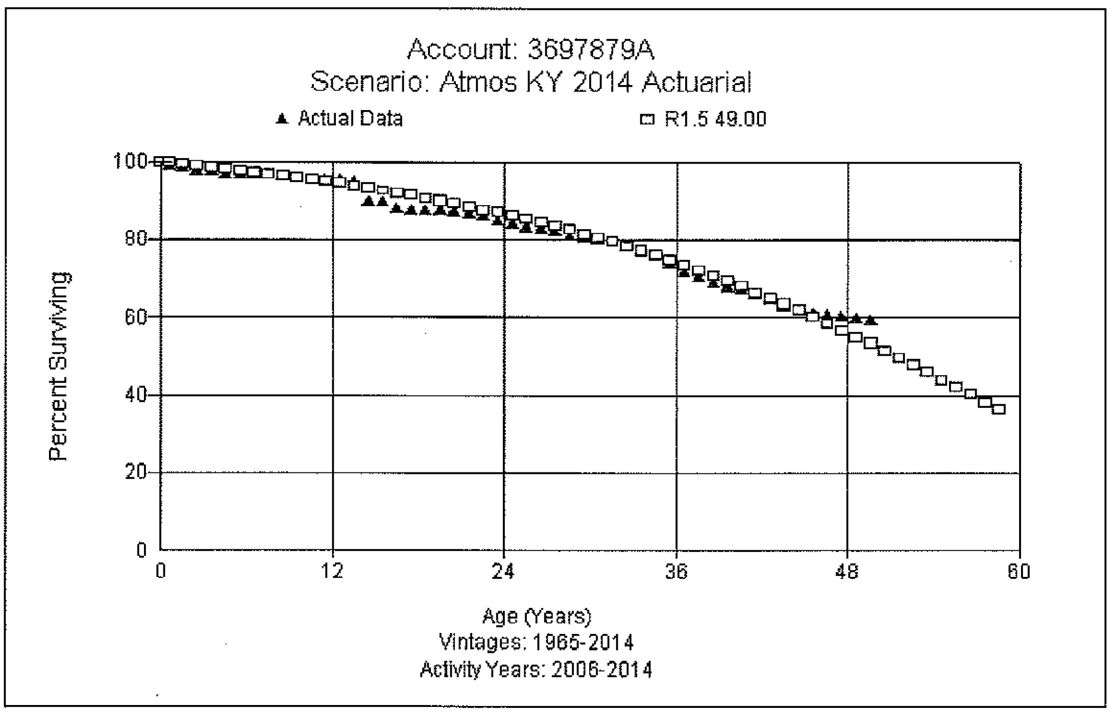
Account 376.01 & 376.02 Mains - Steel and Plastic (55 R3)

These accounts include the cost of steel and plastic mains. There is approximately $144 million total for the accounts combined in this account. The existing life is the 55 R3 dispersion pattern. This account consists of approximately 2,485 miles of steel and 1,437 miles of plastic pipe. Plastic pipe was first installed in the early 1980's and with a few exceptions is the type of pipe that will be installed. Since most of the pipe is in public easements, road moves are one of the primary triggers for retirements and is expected to increase with projected increase in road work in the future. The Commission approved a Pipe Replacement Program (PRP) in 2010, which is a 15 year program. Our life analysis indications suggested the life of mains to be decreasing slightly. However, discussions with Company personnel indicated this should be temporary and likely the result of the PRP. The Company expects the decrease in life of mains will reverse once the PRP is complete. Based on all these factors, this study recommends retaining the existing 55 R3. A comparison of actual versus simulated balances is shown below for the 55 R3.



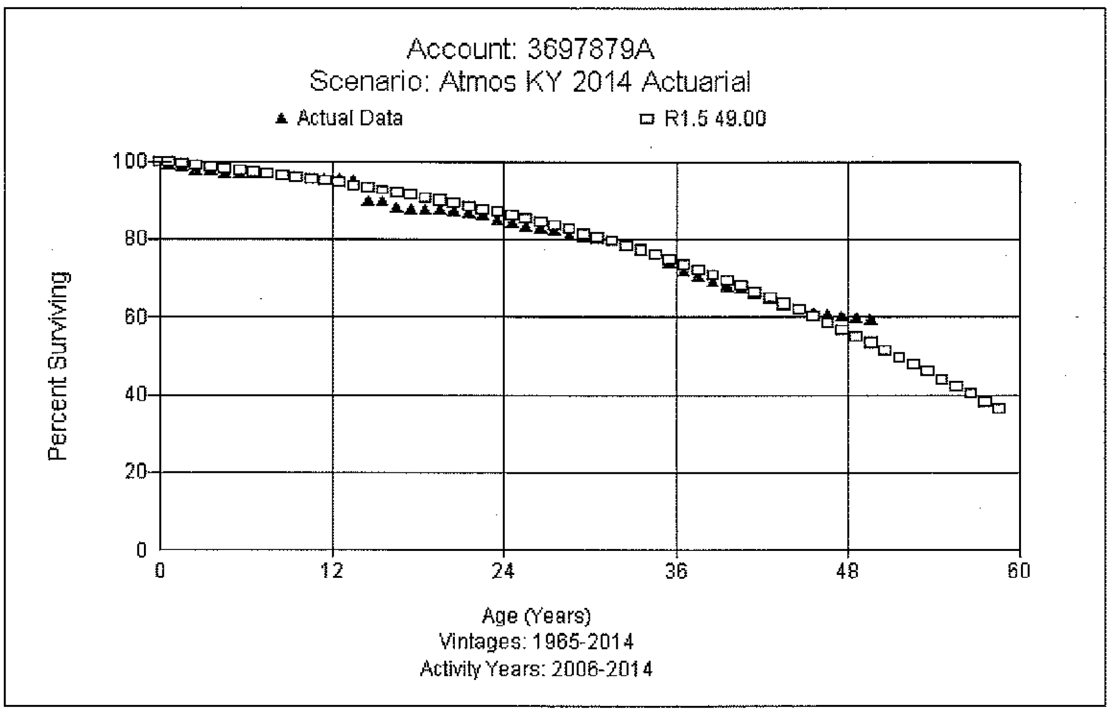
Account 378.00 M&R Station Equipment (49 R1.5)

This account consists of various measuring equipment, regulator station and valves used in distribution operations. There is approximately $5.2 million of investment in this account. The existing life is 49 years with the R2 dispersion. Due to similarities, a combined analysis was performed for all measuring and regulating equipment in Transmission and Distribution functions. Discussions with Company personnel indicated lives of the assets have changed over the years from 60-70 year life expectancy, recent past generation to be 40-50 year life expectancy, to the most current generation, more technology driven, to be 30-40 year life expectancy. Based on the combined analysis the 49 R1.5 was a good fit. This study recommends retaining the 49 year life while moving to a dispersion pattern of R1.5. A graph of the combined accounts observed life table and recommendation is shown below for the R1.5 49.



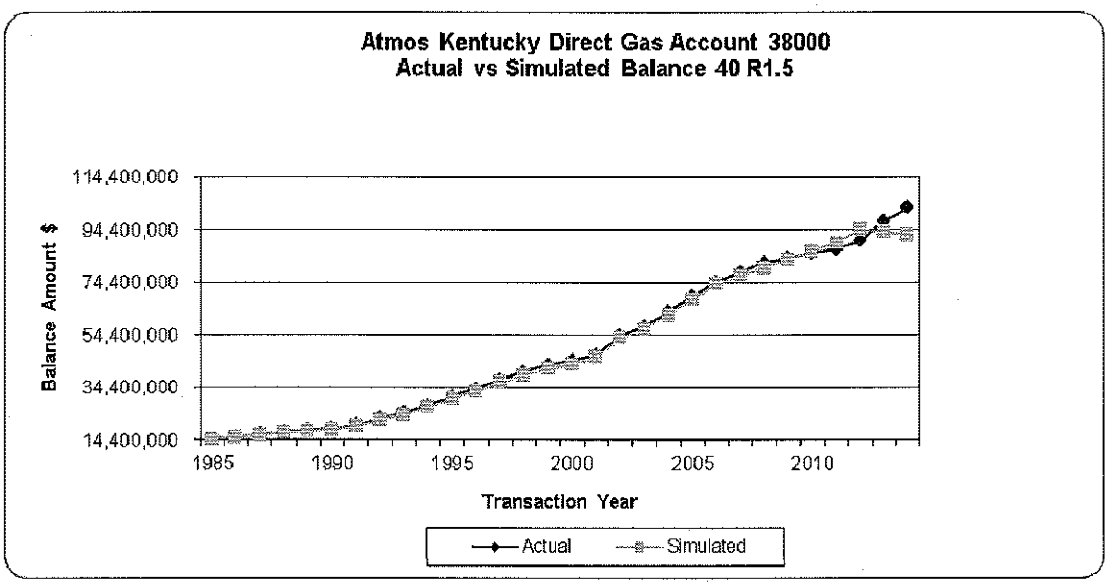
Account 379.00 & 379.05 M&R – City Gate Equipment (49 R1.5)

These accounts include the cost of measuring and regulating stations and other related equipment for city gate. There is approximately $4.1 million total for the accounts combined in this account. The existing life is 49 R2. Due to similarities, a combined analysis was performed for all measuring and regulating equipment in Transmission and Distribution functions. Discussions with Company personnel indicated lives of the assets have changed over the years from 60-70 year life expectancy, recent past generation to be 40-50 year life expectancy, to the most current generation, more technology driven, to be 30-40 year life expectancy. Based on the combined analysis the 49 R1.5 was a good fit. This study recommends retaining the 49 year life while moving to a dispersion pattern of R1.5. A graph of the combined accounts observed life table and recommendation is shown below for the R1.5 49.



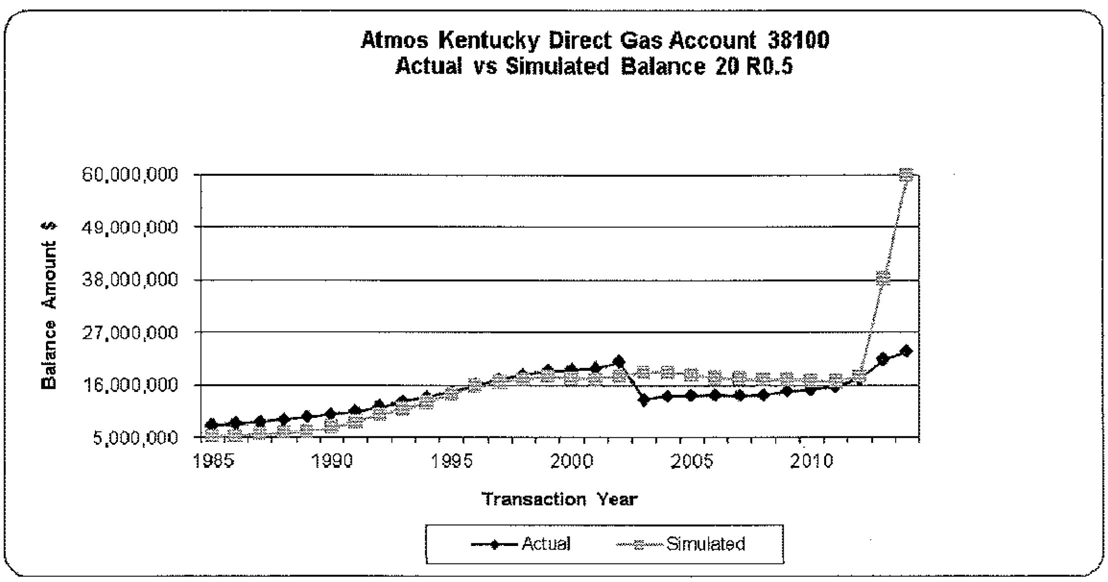
Account 380.00 Services (40 R1.5)

This account consists of all types of services used in distribution operations. There is approximately $103 million of investment in this account. The existing life is 40 years with the R1.5 dispersion. The current average age of investment is 12.70 years. The SPR analysis indicated best fits with excellent Retirement Experience Index (REI) to be around 37 to 38 years. Discussions with Company personnel indicated PRP is causing more replacement in services, which could contribute to lowering the life. In the past few years Atmos changed the designation from customer owned to Atmos owned from main to the meter. Based on the analysis, temporary impact from the PRP, and input from Company personnel, this study recommends retaining the 40 year life and R1.5 dispersion. A comparison of actual versus simulated balances is shown below for the 40 R1.5.



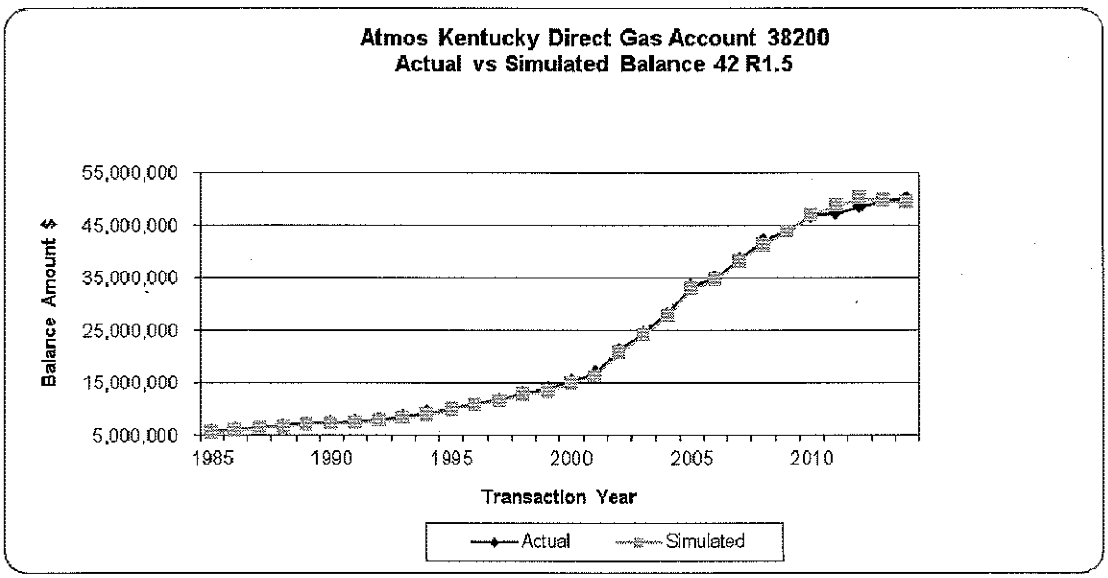
Account 381.00 Meters (20 R0.5)

This account includes the cost of meters. The balance is $23 million and the existing life is 20 R0.5. The current average age of investment is 11 years. This account is undergoing many changes due to the introduction of technology meters. Currently, there are about 600 AMR meters installed. Non-compatible meters have been replaced over the past 6-7 years, with about 1,600-2,000 obsolete meters pulled each year. Company requested approval for 20,000 AMR meters to be implemented each year. New meters are not as durable (plastic) and cost less so meters are no longer repaired but retired. Company has been performing military sampling of meters since 1999. Without sampling, meters would be changed out every 10 years. The SPR analysis suggests the life to be 20 years and less. Based on indications and future plans to implement more AMR meters which are expected to have a life around 20 years, this study recommends retaining the 20 R0.5. A comparison of actual versus simulated balances is shown below for the 20 R0.5.



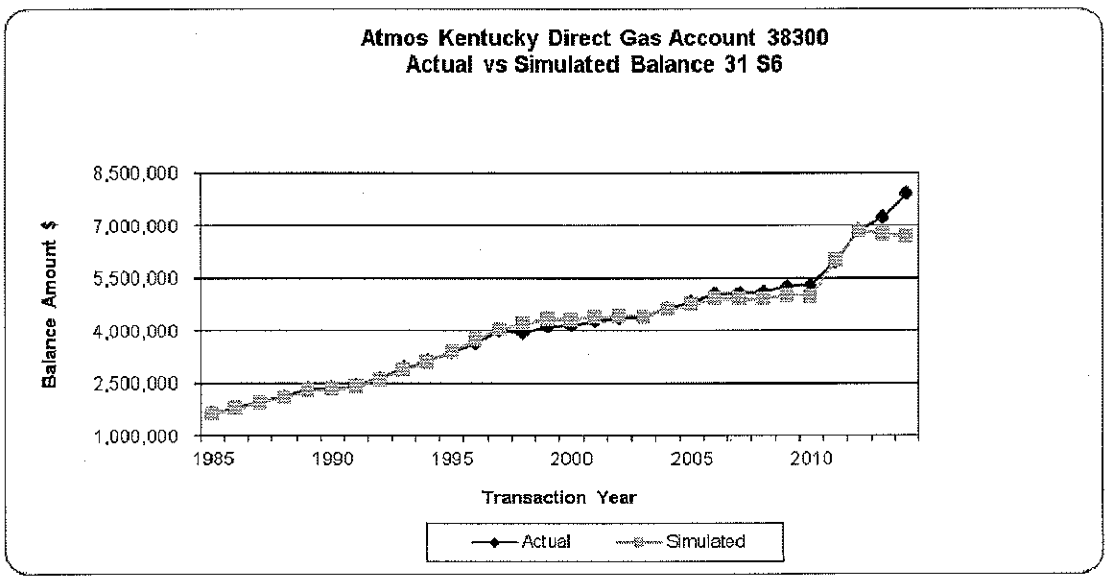
Account 382.00 Meter Installations (42 R1.5)

This account includes the cost of meter installations. This account has a balance of $50 million. The existing life is 42 R1.5. The current average age of investment is approximately 11 years. The SPR analysis best fits range from 38 to 46 years old. Discussions with Company personnel indicated these are not retired when a meter is and would expect to see longer life, which is consistent with the analysis indications. Based on the analysis and Company input, this study recommends retaining the 42 R1.5. A comparison of actual versus simulated balances is shown below for the 42 R1.5.



Account 383.00 House Regulators (31 S6)

This account includes the cost of house regulators. There is approximately $7.9 million in this account. The existing life is a 31 S6. Similar to the meter installation, these assets are evaluated when a meter is being replaced but are not always replaced. Discussions with Company personnel indicated they would expect a longer life than meters, but less than meter installations. The SPR analysis indicates best fits are in the range of 31 to 32 years with steep dispersion pattern, which is a slight increase from existing. Based on the analysis and Company input, this study recommends retaining the 31 S6. A comparison of actual versus simulated balances is shown below for the 31 S6.

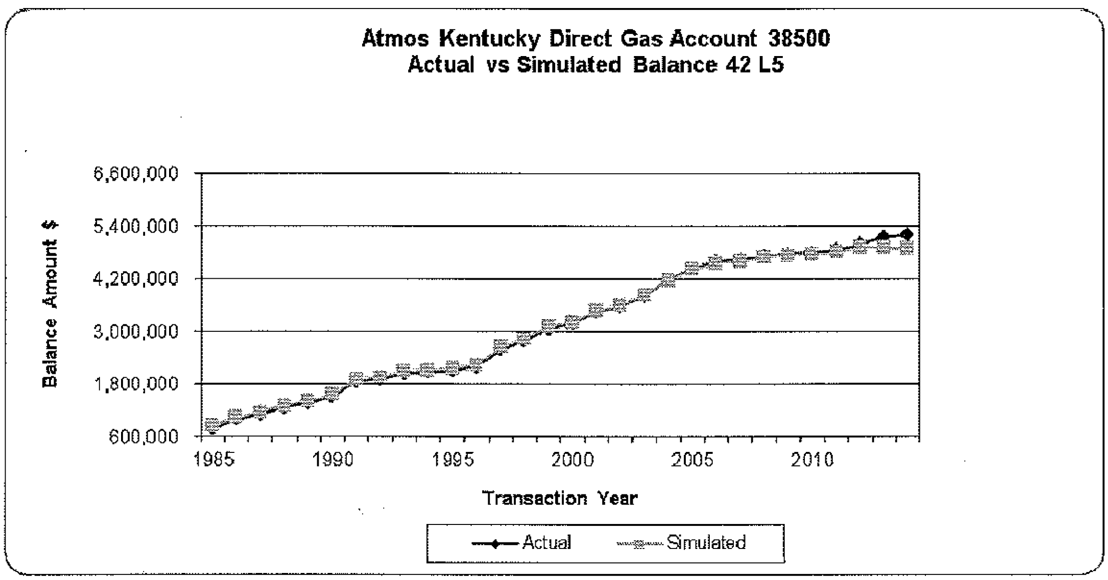


Account 384.00 House Regulator Installations (42 R1.5)

This account includes the cost of house regulators installations. There is approximately $154 thousand in this account. The existing life is a 42 R1.5. This account has limited retirement activity being recorded. Discussions with Company personnel indicated retirements are often recorded to 382 and/or 383. Similar to meter installations, these are not expected to be retired each time house regulator is retired and replaced so a longer life is reasonable. Company is moving to installation of pre-built meter loops (consists of meter installation, house regulator, and house regulator installation), which will eventually merge life expectations into one. For now, due to the lack of retirements recorded into this account, the same parameters, 42 R1.5, for Account 382 Meter Installations is being recommended. No graph is provided.

Account 385.00 Industrial Measuring (42 L5)

This account includes the cost of regulator installations, regulator stations, valves and pressure recorders for industrial customers. There is approximately $5 million in this account. The existing life is a 42 L5. This equipment is more expensive and heavy duty due to its use with industrial customers. These are tested on site and more frequently and only replaced if it fails. Company personnel would expect a slightly longer life, which is indicated in the analysis. This study recommends retaining the 42 L5. A comparison of actual versus simulated balances is shown below for the 42 L5.



General Plant – FERC Accounts 390-399.08

Account 390.00, 390.02, 390.03, & 390.04 Structures and Improvements (40 R2)

These accounts include the cost of buildings, roof, heating/cooling equipment, and carpet. Consistent with the prior study and currently approved rates, all Account 390's, except 390.09, will be combined to calculate a depreciation rate to be applied to each account. There is approximately $3 million total for the accounts combined in this account. The current life is a 40 R2. The life analysis for this account was performed using the actuarial analysis. However, no retirements had been recorded. Based on the plans to own some buildings (not all being leased) and judgment, this study recommends retaining the life of 40 years and the R2 dispersion pattern for this account. No graph is provided.

Account 390.09 Improvements - Leased (20 R3)

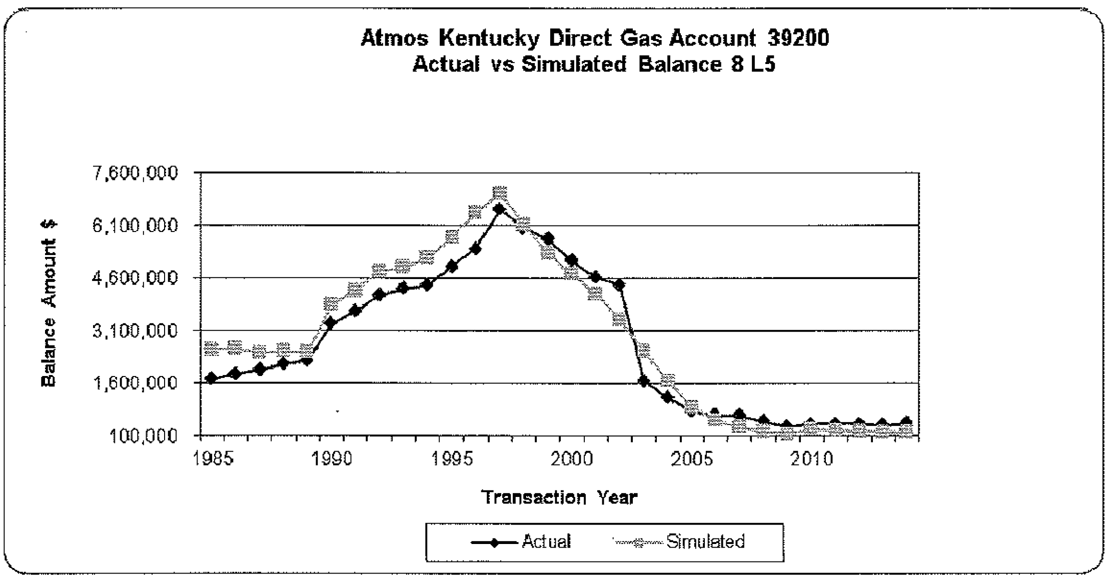
This account includes the cost of improvements to leased buildings. There is approximately $1.3 million in this account. The current life is a 20 R3. The life analysis for this account was performed using the actuarial analysis. However, no retirements had been recorded. Based on the current plans to own buildings and the lease term for major lease buildings being 20 years, this study recommends retaining the life of 20 years and the R3 dispersion pattern for this account, which is consistent with the lease terms.

Account 391.00 & 391.03 Office Furniture, Equipment and Machines (15 SQ)

These accounts consist of miscellaneous office furniture such as desks, chairs, filing cabinets, tables, copiers, and other office equipment used for general utility service. There is approximately $1.5 million in this account. The existing life is 15 SQ and uses vintage group amortization and is retained. No graph is provided.

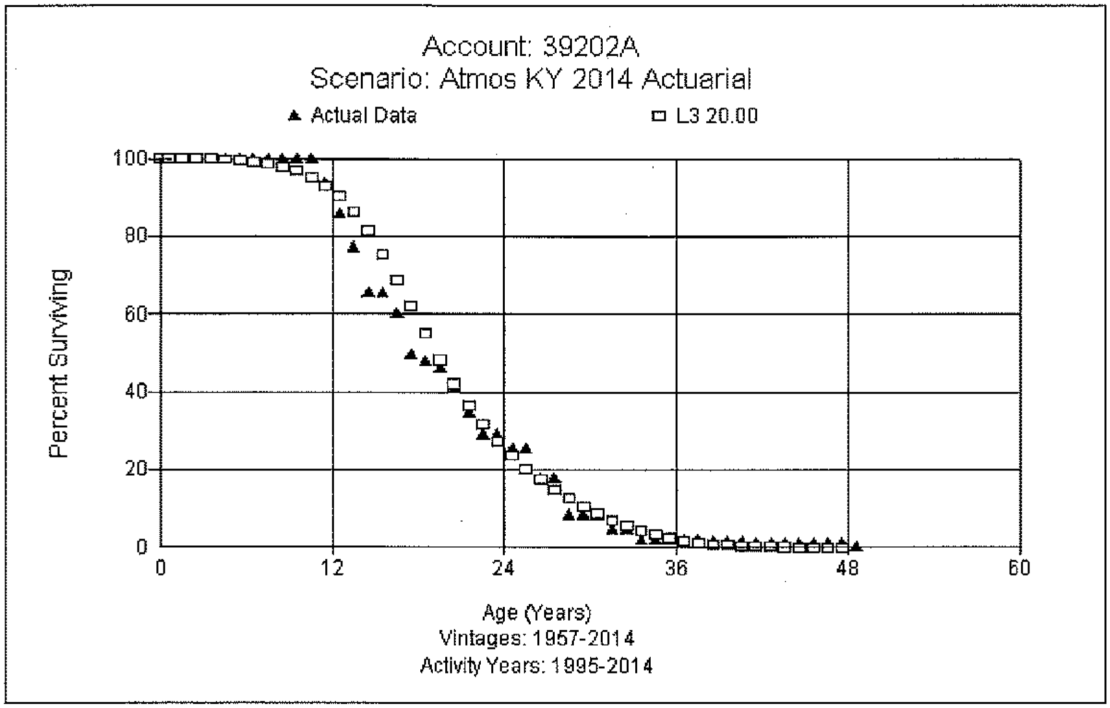
Account 392.00 Transportation Equipment (8 L5)

This account consists of various types of transportation equipment such as cars, trucks, tractor, and trailers. There is approximately $418 thousand in this account. Current parameters are 8 L5. This study recommends retaining the 8 L5 which is reflective of the assets, policy and expectations. A comparison of actual versus simulated balances is shown below for the 8 L5 curve.



Account 392.02 Trailers (20 L3)

This account consists of working trailers used in general plant. There is approximately $33 thousand in this account. Current parameters are 15 L5. This study recommends using a 20 L3 which is reflective of the assets, policy and expectations. A graph of the observed life table and recommendation is shown below for the 20 L3 curve.

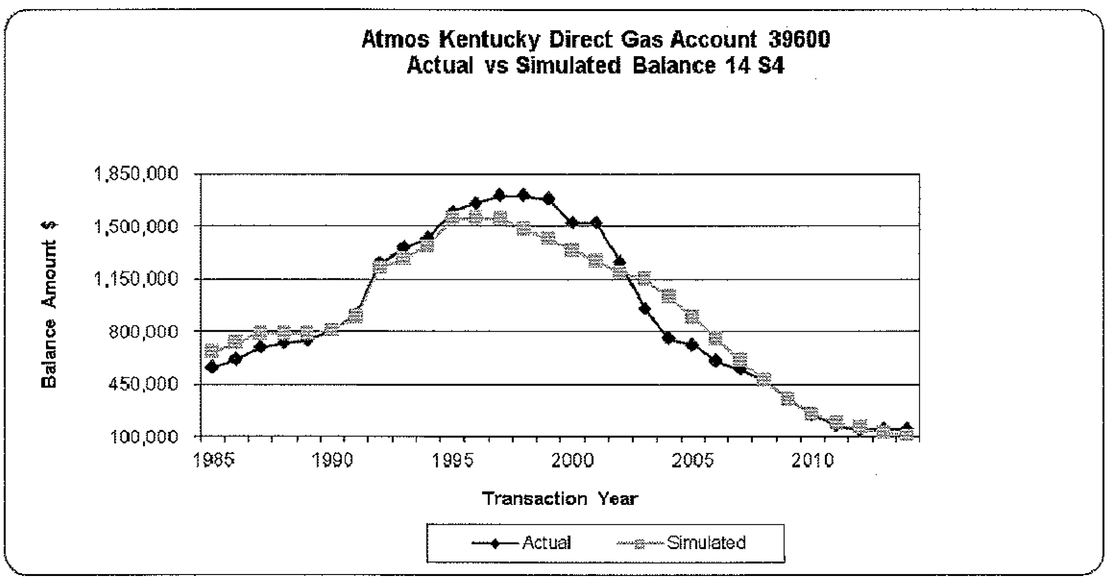


Account 394.00 Tools, Shop, and Garage Equipment (16 SQ)

This account consists of various tools used in the shop and garages such as boring equipment, leak detectors, pipe locators, fusion, tapping, and plugging equipment. There is approximately $1.7 million in this account. The existing life is 16 SQ and uses vintage group amortization and is retained. No graph is provided.

Account 396.03, 396.04, & 396.05 Ditchers, Backhoes and Welders (14 S4)

These accounts consist of power operated equipment including ditchers, backhoes, and welders. There is approximately $150 thousand total for the accounts combined in this account. The current life is 14 years with the S4 dispersion. Based on the analysis and type of equipment, this study recommends retaining the 14 year life and the S4 dispersion. A comparison of actual versus simulated balances is shown below for the 14 S4 curve.



Accounts 397.00 Communication Equipment (15 SQ)

This account consists of all communication equipment including mobile and fixed radio systems along with telephone, telemetering and other miscellaneous communication equipment. There is $332 thousand in this account. The existing life is 15 SQ and uses vintage group amortization and is retained. No graph is provided.

Accounts 397.05 Telemetering (15 S1)

This account consists of all telemetering equipment including ITRON, mobile and fixed radio systems. There is no balance in this account. The existing life is a 15 S1 and is retained for future additions.

Account 398.00 Miscellaneous Equipment (20 SQ)

This account consists of kitchen, audio/video equipment, television, and other miscellaneous equipment used in general utility service. There is approximately $3.7 million in this account. The existing life is a 20 SQ and uses vintage group amortization and is retained. No graph is provided.

Account 399.01 Server Hardware (10 SQ)

This account consists of server hardware computer equipment. There is no balance in this account. The existing life is 10 SQ and uses vintage group amortization and is retained. No graph is provided.

Account 399.02 Server Software (7 SQ)

This account consists of server software. There is no balance in this account. The existing life is 7 SQ and uses vintage group amortization and is retained. No graph is provided.

Account 399.03 – Network Hardware (10 SQ)

This account consists of network hardware computer equipment. There is approximately $82 thousand in this account. The existing life is 10 SQ and uses vintage group amortization and is retained. No graph is provided.

Account 399.06 – PC Hardware (5 SQ)

This account consists of personal computer hardware, laptops, mobile data terminals (MDT), printers, monitors, and projectors. There is approximately $1 million in this account. The existing life is 5 SQ and uses vintage group amortization and is retained. No graph is provided.

Account 399.07 PC Software (7 SQ)

This account consists of software for personal computers. There is approximately $14 thousand in this account. The existing life is 7 SQ and uses vintage group amortization and is retained. No graph is provided.

Account 399.08 Application Software (15 SQ)

This account consists of large application software. The balance in this account is $123 thousand. The existing life is 15 SQ and uses vintage group amortization and is retained. No graph is provided.

Salvage Analysis

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the timing of the original addition versus the retirement. For example, a Distribution asset in FERC Account 376 Steel Mains with a current installed cost of $500 (2014) would have had an installed cost of $33.68[4] in 1959. A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a negative 10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 163 percent removal cost for that asset ($50/$33.68). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets.

The net salvage analysis uses the history of the individual accounts to estimate the future net salvage that Kentucky can expect in its operations. As a result, the analysis not only looks at the historical experience but also takes into account recent and expected changes in operations that could reasonably lead to different future expectations for net salvage than were experienced in the past. Generally, recent experience is more heavily weighted in making net salvage recommendations than experience older than 10 years.

Salvage Characteristics

For each account, data for retirements, gross salvage, and cost of removal

[4] Using the Handy-Whitman Bulletin No. 180, G-2, line 44, $33.68 = $500 x 52/772.

were derived from 1996-2014. Moving averages, which remove timing differences between retirement and salvage and removal cost, were analyzed over periods varying from one to 19 years, which were evaluated in making the net salvage recommendations for the study. However, for purposes of printing in this report, we have limited it to a period of 10 years in Appendix D. A discussion for each account provides the recommended net salvage factor, the existing net salvage factor if known, and any specific considerations given to support the recommendations.

Storage Plant – FERC Accounts 350.20 – 356.00

Account 350.20 Rights-of-Way (0%)

This account includes any salvage and removal cost related to rights of way used in connection with storage plant operations. The existing net salvage is zero percent. No net salvage is expected, a zero percent net salvage is retained.

Account 351.00-351.02 Structures & Improvements and Compressor Station Equipment (-5%)

These accounts include any salvage and removal cost related to structures and improvements and compressor station equipment used in connection with storage plant operations. The existing net salvage is negative 5 percent. Some salvage was recorded due to retirement of a building and the sale of a garage door. This is not expected to reoccur. Overall cost of removal is expected to exceed any salvage in the future. This study recommends retention of the existing negative 5 percent net salvage.

Account 351.03 Measuring and Regulating Station (-5%)

This account includes any salvage and removal cost related to measuring and regulating station equipment used in connection with storage plant operations. The existing net salvage is negative 5 percent and is retained.

Account 351.04 Other Structures (-5%)

This account includes any salvage and removal cost related to other structures used in connection with storage plant operations. The existing net salvage is negative 5 percent. Cost of removal is expected to exceed any salvage. Consistent with other structure accounts a negative 5 percent is recommended.

Account 352.00, 352.01, 352.02 Wells, Well Construction and Well Equipment (-30%)

These accounts include any salvage and removal cost related to wells, well construction, and well equipment used in connection with storage plant operations. The existing net salvage for accounts 352.00 and 352.01 is negative 30 percent while the existing salvage for account 352.02 is negative 50 percent. The Company has approximately 55 wells across 5 storage fields. One well, Bon Harbor, was recently retired. Company estimates it would cost approximately $10 thousand per well to retire. Based on the combined analysis and the overall indications, this study recommends a negative 30 percent for all three accounts.

Account 352.03 Cushion Gas (0%)

This account includes any salvage and removal cost related to cushion gas used in connection with storage plant operations. Currently there is no net salvage recorded for this account and a zero percent net salvage is retained.

Account 352.10 Storage Leaseholds (0%)

This account includes any salvage and removal cost related to storage leaseholds used in connection with storage plant operations. There is no salvage or cost of removal recorded or expected. This study recommends retaining the approved zero percent net salvage for this account.

Account 352.11 Storage Rights (0%)

This account includes any salvage and removal cost related to storage rights used in connection with storage plant operations. The existing net salvage is zero percent and is retained.

Account 353.01, 353.02 Storage Field and Tributary Lines (-5%)

These accounts include any salvage and removal cost related to field and tributary lines used in connection with storage plant operations. Currently, the net salvage for these accounts is negative 5 percent and is retained.

Account 354.00 Compressor Station Equipment (0%)

This account includes any salvage and removal cost related to compressor station equipment used in connection with storage plant operations. Currently, the net salvage is zero percent. Some salvage and cost of removal was recorded but the overall indications net to zero percent and gross salvage levels are not likely to be repeated. This study recommends retention of zero percent.

Account 355.00 Measuring and Regulating (-4%)

This account includes any salvage and removal cost related to measuring and regulating equipment used in connection with storage plant operations. The existing net salvage is negative 4 percent. There has been some activity with no salvage and some cost of removal. Based on the overall analysis indications, this study recommends retaining a negative 4 percent net salvage for this account.

Account 356.00 Purification Equipment (-3%)

This account includes any salvage and removal cost related to purification equipment used in connection with storage plant operations. The existing net salvage is negative 3 percent and is retained.

Transmission Plant – FERC Accounts 365.20 – 369.01

Account 365.20 Rights-of-Way (0%)

This account includes any salvage and removal cost related to rights of way used in connection with transmission operations. The existing net salvage is zero percent and is retained.

Account 366.02 & 366.03 Meas. & Reg. Station Structures & Other Structures (-6%)

These accounts include any salvage and removal cost related to measuring and regulating station structures and other structures used in connection with transmission operations. The existing net salvage is negative 6 percent. The combined account analysis indicates some salvage and cost of removal recorded for these two accounts. Salvage in 2008 was for a fence and is not likely to reoccur. Based on the overall analysis indications and expectations that cost of removal will exceed any salvage, this study recommends retention of negative 6 percent net salvage for these accounts.

Account 367.00 Mains – Cathodic Protection (0%)

This account includes any salvage and removal cost related to cathodic protection mains used in connection with transmission operations. These assets generally do not incur cost of removal and there is no salvage. Currently the net salvage for this account is zero percent and is retained.

Account 367.01 Mains – Steel (-20%)

This account includes any salvage and removal cost related to steel mains used in connection with transmission operations. Currently, the net salvage for this account is negative 30 percent. The Company recently completed a separate Time and Motion Study to evaluate the costs related to retirement activities for its Mains and Services. The results of this study are factored into the net salvage analysis for this account. The current analysis indicates a continued pattern of negative net salvage with a range of negative 20 to negative 19 percent for the five and ten year averages. Based on the indications in the time and motion study, this study recommends moving to negative 20 percent net salvage at this time.

Account 369.00 & 369.01 Measuring and Reg. Station (-19%)

These accounts include any salvage and removal cost related to measuring and regulating station equipment used in connection with transmission operations. The existing net salvage for these accounts is negative 9 percent. Using the combined analysis, overall indications suggest there is no salvage and some cost of removal will be incurred. Based on the overall indications in the combined analysis, this study recommends moving to negative 19 percent net salvage for this account.

Distribution Plant – FERC Accounts 374.02-387

Account 374.02 Land Rights (0%)

This account includes any salvage and removal cost related to land rights used in connection with distribution operations. Existing net salvage is zero percent. Very small salvage was recorded, but not expected to occur in the future. This study recommends retaining the zero percent net salvage for this account.

Account 375.00, 375.01, 375.02, & 375.03 Structures and Improvements (All) (-10%)

These accounts consist of any salvage and removal cost related to buildings, border station and regulating station structures, fences, and other miscellaneous related assets used in connection with distribution operations. The existing net salvage is negative 10 percent. The combined analysis indicates no salvage and some cost of removal being incurred. The overall indications suggest a negative 50 percent, but this is not reasonable to expect for all assets in the future. This study recommends retaining the existing negative 10 percent net salvage for this account.

Account 376.00 Mains - Cathodic Protected (0%)

This account consists of any salvage and removal cost related to cathodic protected mains. The existing net salvage is zero percent. The existing is due to the combined analysis with mains. This study has segregated anodes, rectifiers and leak clamps in this account and there is no salvage or cost of removal expected. Therefore, this study recommends a zero percent net salvage for this account.

Account 376.01 Mains - Steel (-5%)

This account consists of any salvage and removal cost related to steel mains. The existing net salvage is negative 20 percent. The Company recently completed a separate Time and Motion Study to evaluate the costs related to retirement activities for its Mains and Services. The results of this study are factored into the net salvage analysis for this account. The current analysis indicates a continued pattern of negative net salvage with an overall negative 6 percent for the most recent full moving average. More recent moving averages are around negative 2 and negative 3 percent. Based on the combined analysis for both steel and plastic, this study recommends using negative 5 percent net salvage for both steel and plastic mains at this time.

Account 376.02 Mains - Plastic (-5%)

This account consists of any salvage and removal cost related to plastic mains. The existing net salvage is negative 20 percent. The Company recently completed a separate Time and Motion Study to evaluate the costs related to retirement activities for its Mains and Services. The results of this study are factored into the net salvage analysis for this account. The current analysis indicates a continued pattern of negative net salvage with an overall negative 6 percent for the most recent full moving average. More recent net salvage (5 and 10 year) moving averages are around negative 2 to negative 3 percent. Based on the combined analysis for both steel and plastic and long and short term indications, this study recommends using negative 5 percent net salvage for both steel and plastic mains at this time.

Account 378.00 M&R Station Equipment (-19%)

This account includes any salvage and removal cost related to measuring equipment, regulator station and valves used in distribution operations. The existing net salvage is negative 25 percent. Consistent with the life analysis, a combined analysis was run for all measuring and regulating equipment in the transmission and distribution functions. Based on that combined analysis, the overall indications are negative 19 percent, which is the recommendation of this study.

Account 379.00 & 379.05 M&R – City Gate Equipment (-19%)

These accounts include any salvage and removal cost related to station equipment used in measuring and regulating gas at the city gate. The existing net salvage is negative 13 percent. Consistent with the life analysis, a combined analysis was run for all measuring and regulating equipment in the transmission and distribution functions. Based on that combined analysis, the overall indications are negative 19 percent, which is the recommendation of this study.

Account 380.00 Services (-20%)

This account includes any salvage and removal cost related to all types of services related to distribution operations. The existing net salvage is negative 55 percent. Consistent negative net salvage indications are shown in every year except one, 2009, which may be a result of timing differences. The Company recently completed a separate Time and Motion Study to evaluate the costs related to retirement activities for its Mains and Services. The results of this study are factored into the net salvage analysis for this account. The current analysis indicates a continued pattern of negative net salvage with an overall negative 20 percent for the most recent full moving average. More recent (5 and 10 year) moving averages range from negative 5 to negative 6 percent. Based on the results of that study and the overall indications, this study recommends moving to a negative 20 percent net salvage for this account.

Account 381.00 Meters (-50%)

This account includes any salvage and removal cost related to meters. The existing net salvage is negative 50 percent. Looking to the future where meter loop will be installed and removed as one unit, a combined analysis for accounts 381 and 382 and all four accounts 381-384 were made. Both combined analysis overall indications suggest more negative than the existing negative 50%, to be reasonable. Based on future expectations and the combined overall indications, this study recommends maintaining a negative 50 percent net salvage for this account at this time.

Account 382.00 Meter Installations (-50%)

This account includes any salvage and removal cost related to meter installations. The existing net salvage is negative 50 percent. Individually, this account has very high negative net salvage, (negative 171%). The combined analysis overall indications suggest a more negative net salvage than the existing, but is more reasonable for future expectations. Based on these factors and the combined overall indications, this study recommends retaining a negative 50 percent net salvage for this account.

Account 383.00 House Regulators (0%)

This account includes any salvage and removal cost related to house regulators. The existing net salvage is zero percent. A combined analysis was performed and used for Accounts 381 and 382. However, this account and Account 384 have been treated differently in the past. Until the Company actually implements the one meter loop asset and the experience can be evaluated, it is our recommendation to retain the existing zero percent net salvage.

Account 384.00 House Regulator Installations (0%)

This account includes any salvage and removal cost related to house regulator installations. The existing net salvage is zero percent. Very little activity is recorded. See discussions for Accounts 381, 382, and 383. This study recommends retaining the zero percent net salvage for this account.

Account 385.00 Industrial Measuring (-12%)

This account includes any salvage and removal cost related to meters, regulator installations, regulator stations, valves and pressure recorders for industrial customers. The existing net salvage is negative 25 percent. The more recent analysis indicates more negative net salvage is being incurred. 2012 is much more negative and 2014 was positive but may be the result of timing differences. The overall net salvage indications across the most recent year are almost negative 12 percent, which is the recommendation in this study.

General Plant – FERC Accounts 390-399.08

Account 390.00, 390.02, 390.03, & 390.04 Structures and Improvements (-10%)

These accounts include the gross salvage and cost or removal for costs of structures and improvements used for utility service. The existing net salvage is negative 10 percent. The combined analysis indicates a negative 10 percent, which is reasonable for these types of assets. Based upon the analysis, this study recommends retaining a negative 10 percent net salvage for these accounts at this time.

Account 390.09 Improvements – Leased (0%)

This account includes the gross salvage and cost or removal for costs of improvements to leased structures used for utility service. The existing net salvage is zero percent. Some salvage was recorded in 2008 but is not likely to reoccur at those levels. This study recommends retaining zero percent net salvage for this account at this time.

Account 391.00 & 391.03 Office Furniture & Equipment and Office Machines (0%)

These accounts include the gross salvage and cost or removal for office furniture, equipment and office machines used for utility service. The existing net salvage is zero percent. No significant salvage or cost of removal is expected. This study recommends retaining zero percent net salvage for this account at this time.

Account 392.00 Transportation Equipment (10%)

This account consists of gross salvage and cost of removal for cars, trucks, and other transportation equipment that can be licensed on roadways. The existing net salvage is 10 percent. No cost of removal is expected nor recorded. Overall analysis indicates positive 10 percent, which is the recommendation of this study.

Account 392.02 Working Trailers (14%)

This account consists of gross salvage and cost of removal for working trailers. The existing net salvage is 14 percent. Overall indications would suggest more salvage is being received than existing. Based upon the overall analysis indications, this study recommends retention of the 14 percent net salvage for this account at this time.

Account 394.00 Tools, Shop, and Garage Equipment (0%)

This account includes the gross salvage and cost or removal for tools, shop, and garage equipment used for utility service. The existing net salvage is 1 percent. The overall analysis indications indicate a zero percent, but due to the type of assets no salvage at end of life is expected. This study recommends retaining a zero percent net salvage for this account at this time.

Account 396.03, 396.04, and 396.05 Power Operated Equipment and Backhoes (8%)

These accounts include the gross salvage and cost or removal for ditchers, backhoes, welders, and other power operated equipment that cannot be licensed on roadways. The existing net salvage is 8 percent. A combined analysis was performed, which indicated some positive net salvage is being recorded. Based on the overall indications and more recent activity, this study recommends retaining the 8 percent net salvage for this account at this time.

Accounts 397.00 Communication Equipment (0%)

This account includes the gross salvage and cost or removal for telephone communication equipment. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining zero percent net salvage for this account.

Accounts 397.05 Telemetering Equipment (0%)

This account includes the gross salvage and cost or removal for telemetering equipment. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining zero percent net salvage for this account.

Account 398.00 Miscellaneous Equipment (0%)

This account includes the gross salvage and cost or removal for miscellaneous equipment. The existing net salvage is zero percent. Small negative net salvage is indicated, but these assets typically will not produce any gross salvage or removal cost at end of life. This study recommends retaining zero percent net salvage for this account.

Account 399.01 Server Hardware (0%)

This account consists of gross salvage and cost of removal for server hardware computer equipment. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining zero percent net salvage for this account.

Account 399.02 Server Software (0%)

This account consists of gross salvage and cost of removal for server software. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining zero percent net salvage for this account.

Account 399.03 Network Hardware (0%)

This account consists of gross salvage and cost of removal for network hardware computer equipment. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining zero percent net salvage for this account.

Account 399.06 PC Hardware (0%)

This account consists of gross salvage and cost of removal for personal computer hardware, laptop, printers, monitors, and projectors. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining a zero percent net salvage for this account.

Account 399.07 PC Software (0%)

This account consists of gross salvage and cost of removal for software for personal computers. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining zero percent net salvage for this account.

Account 399.08 Application Software (0%)

This account consists of gross salvage and cost of removal for large application software. The existing net salvage is zero percent. Typically, these assets do not produce any gross salvage or removal cost. This study recommends retaining zero percent net salvage for this account.

APPENDIX A

Comparison of Depreciation Rates

Appendix A

Atmos Energy Corporation - Kentucky Properties
Comparison of Depreciation Expense
Existing vs Proposed Depreciation Accrual Rates
As of September 30, 2014

			Existing		Proposed		Change in
Account	Description	Plant Balance	Annual Accrual Rate	Annual Accrual	Annual Accrual Rate	Annual Accrual	Depreciation Expense
(a)	(b)	(c)	(d)	(e)	[f]	[g]	[h]
	STORAGE PLANT						
35020	Rights-Of-Way	$ 4,681.58	0.12%	$ 5.44	0.25%	$ 11.78	$ 6.33
35100	Structures & Improvements	17,916.19	1.66%	296.58	1.67%	299.64	3.06
35102	Compressor Station Equipment	153,261.30	1.13%	1,730.62	1.26%	1,931.44	200.82
35103	M&R Station Equipment	23,138.38	0.70%	162.57	0.92%	212.60	50.03
35104	Other Structures	137,442.53	1.18%	1,618.75	1.30%	1,787.00	168.24
35200	Wells	5,870,417.93	1.89%	110,872.46	1.93%	113,193.46	2,321.01
35201	Well Construction	1,699,998.54	1.43%	24,385.02	1.51%	25,740.01	1,354.99
35202	Well Equipment	424,750.24	0.64%	2,732.65	0.93%	3,937.04	1,204.39
35203	Cushion Gas	1,694,832.96	1.76%	29,876.23	1.80%	30,472.58	596.35
35210	Storage Leaseholds	178,530.09	0.07%	127.25	0.35%	630.45	503.20
35211	Storage Rights	54,614.27	0.71%	386.53	0.88%	480.44	93.91
35301	Storage Field Lines	178,496.90	0.22%	386.25	0.81%	1,438.48	1,052.23
35302	Storage Tributary Lines	209,458.21	0.22%	453.25	0.81%	1,688.00	1,234.75
35400	Compressor Station Equipment	923,446.05	1.66%	15,304.93	1.80%	16,654.90	1,349.97
35500	M&R Equipment	240,883.03	0.98%	2,365.65	0.51%	1,223.21	(1,142.44)
35600	Purification Equipment	414,663.45	0.41%	1,713.07	2.05%	8,481.41	6,768.34
	Total Storage	12,226,531.65	1.57%	192,417.25	1.70%	208,182.42	15,765.17
	TRANSMISSION PLANT						
36520	Rights-Of-Way	867,772.00	1.53%	13,316.67	1.33%	11,525.96	(1,790.71)
36602	M&R Station Structures	49,001.72	1.84%	903.49	1.78%	874.32	(29.16)
36603	Other Structures	60,826.29	1.84%	1,121.51	1.78%	1,085.30	(36.20)
36700	Mains - Cathodic Protection	185,508.80	5.00%	9,275.44	5.00%	9,275.44	-
36701	Mains - Steel	27,845,816.36	2.11%	587,411.33	1.89%	527,060.11	(60,351.22)
36900	M&R Station Equipment	615,021.88	2.11%	12,973.97	2.14%	13,157.64	183.67
36901	M&R Station Equipment	2,273,521.01	2.05%	46,537.22	2.14%	48,639.22	2,102.00
	Total Transmission	31,897,468.06	2.11%	671,539.62	1.92%	611,618.00	(59,921.62)

Appendix A

Atmos Energy Corporation - Kentucky Properties
Comparison of Depreciation Expense
Existing vs Proposed Depreciation Accrual Rates
As of September 30, 2014

			Existing		Proposed		Change in
			Annual	Annual	Annual	Annual	Depreciation
Account	Description	Plant Balance	Accrual Rate	Accrual	Accrual Rate	Accrual	Expense
(a)	(b)	(c)	(d)	(e)	[f]	[g]	[h]
	DISTRIBUTION PLANT						
37402	Land Rights	333,416.21	1.72%	5,748.86	1.46%	4,852.29	(896.56)
37500	Structures & Improvements	336,167.54	2.17%	7,299.68	2.06%	6,930.64	(369.04)
37501	Structures & Improvements	99,818.13	2.17%	2,167.49	2.06%	2,057.91	(109.58)
37502	Land Rights	46,591.01	2.17%	1,011.70	2.06%	960.55	(51.15)
37503	Improvements	4,005.08	2.17%	86.97	2.06%	82.57	(4.40)
37600	Mains - Cathodic Protection	20,715,876.26	5.00%	1,035,793.81	5.00%	1,035,793.81	-
37601	Mains - Steel	83,874,801.30	2.45%	2,052,797.06	2.09%	1,757,111.41	(295,685.65)
37602	Mains - Plastic	60,719,621.91	2.45%	1,486,084.73	2.09%	1,272,028.53	(214,056.20)
37800	M&R Station Equipment	5,234,987.30	3.07%	160,490.62	2.89%	151,266.42	(9,224.20)
37900	M&R Station Equipment	2,717,835.64	2.64%	71,809.52	2.86%	77,861.81	6,052.29
37905	M&R Station Equipment - City	1,395,942.13	2.64%	36,883.00	2.86%	39,991.60	3,108.59
38000	Services	102,590,800.63	4.61%	4,730,146.70	3.47%	3,559,713.32	(1,170,433.38)
38100	Meters	22,987,935.79	8.03%	1,845,746.48	8.30%	1,907,793.64	62,047.16
38200	Meter Installations	50,095,568.21	4.41%	2,207,726.88	4.13%	2,070,337.29	(137,389.60)
38300	House Regulators	7,896,127.45	3.31%	261,452.85	3.14%	247,996.53	(13,456.32)
38400	House Regulator Installations	154,276.36	2.53%	3,896.66	2.35%	3,627.39	(269.27)
38500	Industrial M&R	5,196,745.91	3.18%	165,335.06	2.71%	140,609.78	(24,725.28)
	Total Distribution	364,400,516.86	3.86%	14,074,478.08	3.37%	12,279,015.51	(1,795,462.57)
	GENERAL PLANT - DEPRECIATED						
39000	Structures & Improvements	2,139,227.33	3.77%	80,545.53	3.76%	80,456.72	(88.81)
39002	Structures - Brick	173,114.85	3.77%	6,518.07	3.76%	6,510.88	(7.19)
39003	Improvements	725,021.86	3.77%	27,298.30	3.76%	27,268.20	(30.10)
39004	Air Conditioning Equipment	7,461.49	3.77%	280.94	3.76%	280.63	(0.31)
39009	Improvements - Leased	1,279,375.74	14.41%	184,331.83	18.71%	239,309.46	54,977.63
39200	Transportation Equipment	417,941.26	16.93%	70,753.54	15.14%	63,292.42	(7,461.12)
39202	Transportation - Trailers	33,191.91	25.88%	8,590.57	9.95%	3,302.66	(5,287.91)
39603	Power Operated -Ditchers	53,703.66	15.58%	8,367.79	19.47%	10,458.69	2,090.90
39604	Power Operated - Backhoes	62,747.29	15.58%	9,776.92	19.47%	12,219.92	2,443.00
39605	Power Operated - Welders	33,235.94	15.58%	5,178.63	19.47%	6,472.64	1,294.01
	Total General Depreciated	4,925,021.33	8.16%	401,642.11	9.13%	449,572.22	47,930.11
	Total Depreciated Plant	413,449,537.90	3.71%	15,340,077.06	3.28%	13,548,388.15	(1,791,688.92)

Appendix A

Atmos Energy Corporation - Kentucky Properties
Comparison of Depreciation Expense
Existing vs Proposed Depreciation Accrual Rates
As of September 30, 2014

			Existing		Proposed			Change in
Account	Description	Plant Balance	Annual Accrual Rate	Annual Accrual	Annual Accrual Rate	Annual Accrual		Depreciation Expense
(a)	(b)	(c)	(d)	(e)	[f]	[g]		[h]
	GENERAL PLANT - AMORTIZED							
39100	Office Furniture & Equipment	1,450,410.05	6.67%	96,694.00	6.67%	96,694.00	(1)	-
39400	Tools, Shop, & Garage	1,738,369.71	6.25%	108,648.11	6.25%	108,648.11	(1)	-
39700	Communication Equipment	332,721.76	6.67%	22,181.45	6.67%	22,181.45	(1)	-
39800	Miscellaneous Equipment	3,668,753.31	5.00%	183,437.67	5.00%	183,437.67	(1)	-
39903	Network Hardware	82,165.27	10.00%	8,216.53	10.00%	8,216.53	(1)	-
39906	PC Hardware	1,021,622.05	20.00%	204,324.41	20.00%	204,324.41	(1)	-
39907	PC Software	13,751.77	14.29%	1,964.54	14.29%	1,964.54	(1)	-
39908	Application Software	123,514.83	6.67%	8,234.32	6.67%	8,234.32	(1)	-
	Total General Amortized	8,431,308.75	7.52%	633,701.02	7.52%	633,701.02		-
	Total General Depreciated & Amortized	13,356,330.08	7.75%	1,035,343.13	8.11%	1,083,273.24		47,930.11
	TOTAL PLANT IN STUDY	$ 421,880,846.65	3.79%	$ 15,973,778.09	3.36%	$ 14,182,089.17		$ (1,791,688.92)
	Annual Amortization for Deficit			409,938.57		561,201.60		151,263.03
	TOTAL DEPRECIATION STUDY			$ 16,383,716.65		$ 14,743,290.77		$ (1,640,425.88)

(1) General Plant - Amortization rate and amount does not include deficit/surplus amount.

APPENDIX B

Calculation of Equal Life Group

Appendix B

ATMOS ENERGY - KENTUCKY PROPERTIES
COMPUTATION OF DEPRECIATION ACCRUAL RATE
AT SEPTEMBER 30, 2014

Using Equal Life Group

Account	Description	Plant In Service 09/30/2014	Allocated Book Depreciation 09/30/2014	Net Salvage %	Net Salvage Amount	Unaccrued Balance	Remaining Life	Annual Accrual Amount	Annual Accrual Rate
	STORAGE PLANT								
35020	Rights-Of-Way	$ 4,681.58	$ 4,489.58	0%	$ -	$ 192.00	16.30	$ 11.78	0.25%
35100	Structures And Improvements	17,916.19	4,801.21	-5%	(895.81)	14,010.79	46.76	299.64	1.67%
35102	Compressor Station Equipment	153,261.30	106,869.72	-5%	(7,663.07)	54,054.65	27.99	1,931.44	1.26%
35103	Measuring And Reg. Station	23,138.38	19,902.19	-5%	(1,156.92)	4,393.11	20.66	212.60	0.92%
35104	Other Structures	137,442.53	93,318.67	-5%	(6,872.13)	50,995.99	28.54	1,787.00	1.30%
35200	Wells	5,870,417.93	692,694.72	-30%	(1,761,125.38)	6,938,848.59	61.30	113,193.46	1.93%
35201	Well Construction	1,699,998.54	1,323,427.96	-30%	(509,999.56)	886,570.14	34.44	25,740.01	1.51%
35202	Well Equipment	424,750.24	468,302.73	-30%	(127,425.07)	83,872.58	21.30	3,937.04	0.93%
35203	Cushion Gas	1,694,832.96	613,056.50	0%	0.00	1,081,776.46	35.50	30,472.58	1.80%
35210	Storage Leaseholds An	178,530.09	168,277.06	0%	0.00	10,253.03	16.26	630.45	0.35%
35211	Storage Rights	54,614.27	42,652.15	0%	0.00	11,962.12	24.90	480.44	0.88%
35300	Storage Field Lines	387,955.11	335,918.65	-5%	(19,397.76)	71,434.22	22.85	3,126.48	0.81%
35400	Compressor Station Equipment	923,446.05	428,968.84	-5%	(46,172.30)	540,649.51	32.46	16,654.90	1.80%
35500	Measuring And Regulating	240,883.03	200,648.71	0%	0.00	40,234.32	32.89	1,223.21	0.51%
35600	Purification Equipment	414,663.45	152,275.44	-4%	(16,586.54)	278,974.55	32.89	8,481.41	2.05%
	Total Storage	12,226,531.65	4,655,604.12		(2,497,294.53)	10,068,222.06		208,182.42	1.70%
	TRANSMISSION PLANT								
36520	Rights-Of-Way	867,772.00	369,967.75	0%	0.00	497,804.25	43.19	11,525.96	1.33%
36600	Meas. & Reg. Sta. Structures	109,828.01	60,885.35	-6%	(6,589.68)	55,532.34	28.34	1,959.63	1.78%
36700	Mains - Cathodic Protection	185,508.80	105,285.07	0%	0.00	80,223.73	8.65	9,275.44	5.00%
36701	Mains - Steel	27,845,816.36	17,001,621.84	-20%	(5,569,163.27)	16,413,357.79	31.14	527,060.11	1.89%
36900	Measuring And Reg. Station	2,888,542.89	1,839,130.44	-19%	(548,823.15)	1,598,235.60	25.86	61,796.86	2.14%
	Total Transmission	31,897,468.06	19,376,890.46		(6,124,576.10)	18,645,153.70		611,618.00	1.92%
	DISTRIBUTION PLANT								
37402	Land Rights	333,416.21	63,226.00	0%	0.00	270,190.21	55.68	4,852.29	1.46%
37500	Structures & Improvements	486,581.76	192,453.88	-10%	(48,658.18)	342,786.05	34.17	10,031.68	2.06%
37600	Mains - Cathodic Protection	20,715,876.26	10,316,480.37	0%	0.00	10,399,395.89	10.04	1,035,793.81	5.00%
37601-02	Mains - Steel & Plastic	144,594,423.21	37,389,112.41	-5%	(7,229,721.16)	114,435,031.96	37.78	3,029,139.94	2.09%
37800	Meas. And Reg. Sta. Equipment	5,234,987.30	1,775,607.95	-19%	(994,647.59)	4,454,026.93	29.44	151,266.42	2.89%
37900	Measuring & Regulating Station Equipment	4,113,777.77	1,537,683.42	-19%	(781,617.78)	3,357,712.12	28.49	117,853.41	2.86%
38000	Services	102,590,800.63	39,951,886.46	-20%	(20,518,160.13)	83,157,074.29	23.36	3,559,713.32	3.47%
38100	Meters	22,987,935.79	15,270,627.19	-50%	(11,493,967.90)	19,211,276.50	10.07	1,907,793.64	8.30%
38200	Meter Installations	50,095,568.21	21,893,772.49	-50%	(25,047,784.11)	53,249,579.83	25.72	2,070,337.29	4.13%
38300	House Regulators	7,896,127.45	3,294,552.98	0%	0.00	4,601,574.47	18.55	247,996.53	3.14%
38400	House Regulator Installations	154,276.36	77,530.14	0%	0.00	76,746.22	21.16	3,627.39	2.35%
38500	Industrial Measuring	5,196,745.91	2,512,458.15	-12%	(623,609.51)	3,307,897.27	23.53	140,609.78	2.71%
	Total Distribution	364,400,516.86	134,275,391.45		(66,738,166.34)	296,863,291.75		12,279,015.51	3.37%
	GENERAL PLANT DEPRECIATED								
39000	Structures & Improvements	3,044,825.53	334,947.65	-10%	(304,482.55)	3,014,360.43	26.32	114,516.43	3.76%
39009	Improvements - Leased	1,279,375.74	555,484.86	0%	0.00	723,890.88	3.02	239,309.46	18.71%
39200	Transportation Equipment	417,941.26	84,941.51	10%	41,794.13	291,205.63	4.60	63,292.42	15.14%
39202	Wkg Trailers	33,191.91	10,959.23	14%	4,646.87	17,585.81	5.32	3,302.66	9.95%
39600	Power Operated Equipment	149,686.89	57,612.55	8%	11,974.95	80,099.39	2.75	29,151.24	19.47%
	Total General Depreciated	4,925,021.33	1,043,945.80		(246,066.61)	4,127,142.13		449,572.22	9.13%
	Total Study Depreciated	413,449,537.90	159,351,831.83		(75,606,103.57)	329,703,809.64		13,548,388.15	3.28%

Appendix B

ATMOS ENERGY - KENTUCKY PROPERTIES
COMPUTATION OF DEPRECIATION ACCRUAL RATE
AT SEPTEMBER 30, 2014

GENERAL PLANT - AMORTIZED Account	Description	Plant Balance 09/30/2014	Reserve 09/30/2014	Theoretical Reserve 09/30/2014	Reserve (Deficit)/Surplus	Reserve Recovery Period (Yrs)	Amortize Reserve Deficit/Surplus
39100	Office Furniture and Equipment - All	1,450,410.05	349,735.04	711,116.96	(361,381.92)	3.00	120,460.64
39400	Tools, Shop, and Garage Equipment	1,738,369.71	296,595.98	603,069.19	(306,473.21)	3.00	102,157.74
39700	Communication Equipment	332,721.76	72,563.02	147,542.52	(74,979.51)	3.00	24,993.17
39800	Miscellaneous Equipment	3,668,753.31	644,544.79	1,310,554.20	(666,009.41)	3.00	222,003.14
39903	Network Hardware	82,165.27	2,020.49	4,108.26	(2,087.77)	3.00	695.92
39906	PC Hardware	1,021,622.05	231,106.22	469,908.74	(238,802.52)	3.00	79,600.84
39907	PC Software	13,751.77	5,314.00	10,804.96	(5,490.96)	3.00	1,830.32
39908	Application Software	123,514.83	27,464.85	55,844.34	(28,379.49)	3.00	9,459.83
	Total General Amortized	**8,431,308.75**	**1,629,344.39**	**3,312,949.19**	**(1,683,604.80)**		**561,201.60**

After Retirements of Assets With Age > Average Service Life

Account	Description	Plant Balance 09/30/2014	Reserve 09/30/2014	Annual Amortization (2)	Accrual For Reserve Deficit/Surplus	Total Amortization	Annual Amortization %
3910C	Office Furniture and Equipment - All	1,450,410.05	349,735.04	96,694.00			6.67%
3910C	Office Furniture and Equipment - All				120,460.64		(3))
3910C	Total					217,154.64	
39400	Tools, Shop, and Garage Equipment	1,738,369.71	296,595.98	108,648.11			6.25%
39400	Tools, Shop, and Garage Equipment				102,157.74		(3))
39400	Total					210,805.84	
39700	Communication Equipment	332,721.76	72,563.02	22,181.45			6.67%
39700	Communication Equipment				24,993.17		(3))
39700	Total					47,174.62	
39800	Miscellaneous Equipment	3,668,753.31	644,544.79	183,437.67			5.00%
39800	Miscellaneous Equipment				222,003.14		(3))
39800	Total					405,440.80	
39903	Network Hardware	82,165.27	2,020.49	8,216.53			10.00%
39903	Network Hardware				695.92		(3))
39903	Total					8,912.45	
39906	PC Hardware	1,021,622.05	231,106.22	204,324.41			20.00%
39906	PC Hardware				79,600.84		(3))
39906	Total					283,925.25	
39907	PC Software	13,751.77	5,314.00	1,964.54			14.29%
39907	PC Software				1,830.32		(3))
39907	Total					3,794.86	
39908	Application Software	123,514.83	27,464.85	8,234.32			6.67%
39908	Application Software				9,459.83		(3))
39908	Total					17,694.15	
	Total General Amortized After Ret	**8,431,308.75**	**1,629,344.39**	**633,701.02**	**561,201.60**	**1,194,902.62**	
		-	-				
	Total Study Depreciated and Amortized	**$ 421,880,846.65**	**$ 160,981,176.22**	**$ 14,182,089.17**	**$ 561,201.60**	**$ 14,743,290.77**	

APPENDIX C

Mortality Characteristics

CASE NO. 2017-00349
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ATTACHMENT 1

Appendix C

Atmos Energy Corporation
Kentucky Properties
Existing and Proposed Parameters
Depreciation Study as of September 30, 2014

		EXISTING PARAMETERS					PROPOSED PARAMETERS				
Account	Description	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage
STORAGE PLANT											
35020	Rights-Of-Way	50	R5	0%	0%	0%	70	R5	0%	0%	0%
35100	Structures & Improvements	60	R5	0%	5%	-5%	60	R5	0%	5%	-5%
35102	Compressor Station Equipment	60	R5	0%	5%	-5%	60	R5	0%	5%	-5%
35103	M&R Station Equipment	60	R5	0%	5%	-5%	60	R5	0%	5%	-5%
35104	Other Structures	60	R5	0%	5%	-5%	60	R5	0%	5%	-5%
35200	Wells	67	S5	0%	30%	-30%	67	S5	0%	30%	-30%
35201	Well Construction	67	S5	0%	30%	-30%	67	S5	0%	30%	-30%
35202	Well Equipment	67	S5	0%	30%	-30%	67	S5	0%	30%	-30%
35203	Cushion Gas	50	SQ	0%	0%	0%	50	SQ	0%	0%	0%
35210	Storage Leaseholds	67	S5	0%	0%	0%	67	S5	0%	0%	0%
35211	Storage Rights	67	S5	0%	0%	0%	67	S5	0%	0%	0%
35301	Storage Field Lines	50	S1	0%	5%	-5%	60	S1	0%	5%	-5%
35302	Storage Tributary Lines	50	S1	0%	5%	-5%	60	S1	0%	5%	-5%
35400	Compressor Station Equipment	51	R3	0%	0%	0%	54	R3	0%	0%	0%
35500	M&R Equipment	45	R5	0%	4%	-4%	46	R5	0%	4%	-4%
35600	Purification Equipment	46	R5	0%	3%	-3%	46	R5	0%	3%	-3%
TRANSMISSION PLANT											
36520	Rights-Of-Way	55	R5	0%	0%	0%	70	R5	0%	0%	0%
36602	M&R Station Structures	53	R4	0%	6%	-6%	53	R4	0%	6%	-6%
36603	Other Structures	53	R4	0%	6%	-6%	53	R4	0%	6%	-6%
36700	Mains - Cathodic Protection	20	SQ	0%	0%	0%	20	SQ	0%	0%	0%
36701	Mains - Steel	57	R4	0%	30%	-30%	57	R4	0%	20%	-20%
36900	M&R Station Equipment	49	R2	0%	9%	-9%	49	R1.5	0%	19%	-19%
36901	M&R Station Equipment	49	R2	0%	9%	-9%	49	R1.5	0%	19%	-19%

Appendix C

Atmos Energy Corporation
Kentucky Properties
Existing and Proposed Parameters
Depreciation Study as of September 30, 2014

		EXISTING PARAMETERS					PROPOSED PARAMETERS				
Account	Description	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage
DISTRIBUTION PLANT											
37402	Land Rights	60	R5	0%	0%	0%	70	R5	0%	0%	0%
37500	Structures & Improvements	57	R2.5	0%	10%	-10%	57	R2.5	0%	10%	-10%
37501	Structures & Improvements	57	R2.5	0%	10%	-10%	57	R2.5	0%	10%	-10%
37502	Land Rights	57	R2.5	0%	10%	-10%	57	R2.5	0%	10%	-10%
37503	Improvements	57	R2.5	0%	10%	-10%	57	R2.5	0%	10%	-10%
37600	Mains - Cathodic Protection	20	SQ	0%	0%	0%	20	SQ	0%	0%	0%
37601	Mains - Steel	55	R3	0%	20%	-20%	55	R3	0%	5%	-5%
37602	Mains - Plastic	55	R3	0%	20%	-20%	55	R3	0%	5%	-5%
37800	M&R Station Equipment	49	R2	0%	25%	-25%	49	R1.5	0%	19%	-19%
37900	M&R Station Equipment	49	R2	0%	13%	-13%	49	R1.5	0%	19%	-19%
37905	M&R Station Equipment - City	49	R2	0%	13%	-13%	49	R1.5	0%	19%	-19%
38000	Services	40	R1.5	0%	55%	-55%	40	R1.5	0%	20%	-20%
38100	Meters	20	R0.5	0%	50%	-50%	20	R0.5	0%	50%	-50%
38200	Meter Installations	42	R1.5	0%	50%	-50%	42	R1.5	0%	50%	-50%
38300	House Regulators	31	S6	0%	0%	0%	31	S6	0%	0%	0%
38400	House Regulator Installations	42	R1.5	0%	0%	0%	42	R1.5	0%	0%	0%
38500	Industrial M&R	42	L5	0%	25%	-25%	42	L5	0%	12%	-12%
GENERAL PLANT - DEPRECIATED											
39000	Structures & Improvements	40	R2	0%	10%	-10%	40	R2	0%	10%	-10%
39002	Structures - Brick	40	R2	0%	10%	-10%	40	R2	0%	10%	-10%
39003	Improvements	40	R2	0%	10%	-10%	40	R2	0%	10%	-10%
39004	Air Conditioning Equipment	40	R2	0%	10%	-10%	40	R2	0%	10%	-10%
39009	Improvements - Leased	20	R3	0%	0%	0%	20	R3	0%	0%	0%
39200	Transportation Equipment	8	L5	10%	0%	10%	8	L5	10%	0%	10%
39202	Wkg Trailers	15	L5	14%	0%	14%	20	L3	14%	0%	14%
39603	Ditchers	14	S4	8%	0%	8%	14	S4	8%	0%	8%
39604	Backhoes	14	S4	8%	0%	8%	14	S4	8%	0%	8%
39605	Welders	14	S4	8%	0%	8%	14	S4	8%	0%	8%

Appendix C

Atmos Energy Corporation
Kentucky Properties
Existing and Proposed Parameters
Depreciation Study as of September 30, 2014

		EXISTING PARAMETERS					PROPOSED PARAMETERS				
Account	Description	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage	ASL	Iowa Curve	Gross Salvage	Cost of Removal	Net Salvage
GENERAL PLANT - AMORTIZED											
39100	Office Furniture & Equipment	15	SQ	0%	0%	0%	15	SQ	0%	0%	0%
39400	Tools, Shop, & Garage	16	SQ	0%	0%	0%	16	SQ	0%	0%	0%
39700	Communication Equipment	15	SQ	0%	0%	0%	15	SQ	0%	0%	0%
39800	Miscellaneous Equipment	20	SQ	0%	0%	0%	20	SQ	0%	0%	0%
39903	Network Hardware	10	SQ	0%	0%	0%	10	SQ	0%	0%	0%
39906	PC Hardware	5	SQ	0%	0%	0%	5	SQ	0%	0%	0%
39907	PC Software	7	SQ	0%	0%	0%	7	SQ	0%	0%	0%
39908	Application Software	15	SQ	0%	0%	0%	15	SQ	0%	0%	0%

APPENDIX D
Net Salvage

CASE NO. 2017-00349
FR 16(7)(s)
ATTACHMENT 1

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
33400	1996	0.00	0.00	0.00	0.00	NA									
33400	1997	0.00	0.00	0.00	0.00	NA	NA								
33400	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
33400	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
33400	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
33400	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
33400	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
33400	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
33400	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
33400	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33400	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33400	2007	6,084.38	0.00	206.91	(206.91)	-3.40%	-3.40%	-3.40%	-3.40%	-3.40%	-3.40%	-3.40%	-3.40%	-3.40%	-3.40%
33400	2008	0.00	0.00	2,552.05	(2,552.05)	NA	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%
33400	2009	0.00	0.00	0.00	0.00	NA	NA	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%
33400	2010	0.00	0.00	0.00	0.00	NA	NA	NA	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%
33400	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%
33400	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-45.34%	-45.34%	-45.34%	-45.34%	-45.34%
33400	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-45.34%	-45.34%	-45.34%	-45.34%
33400	2014	183,204.41	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-1.39%	-1.46%	-1.46%	-1.46%
33600	1996	0.00	0.00	0.00	0.00	NA									
33600	1997	0.00	0.00	0.00	0.00	NA	NA								
33600	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
33600	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
33600	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
33600	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
33600	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
33600	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
33600	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
33600	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
33600	2014	44,219.30	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35100	1996	0.00	0.00	0.00	0.00	NA									
35100	1997	0.00	0.00	0.00	0.00	NA	NA								
35100	1998	589.00	619.00	0.00	619.00	105.09%	105.09%	105.09%							
35100	1999	0.00	0.00	0.00	0.00	NA	105.09%	105.09%	105.09%						
35100	2000	0.00	0.00	0.00	0.00	NA	NA	105.09%	105.09%	105.09%					
35100	2001	0.00	0.00	0.00	0.00	NA	NA	NA	105.09%	105.09%	105.09%				
35100	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	105.09%	105.09%	105.09%			
35100	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	105.09%	105.09%	105.09%		
35100	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	105.09%	105.09%	105.09%	
35100	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	105.09%	105.09%	105.09%
35100	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	105.09%	105.09%
35100	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	105.09%
35100	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35100	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35100	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35100	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35100	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
35100	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35100	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35104	1996	0.00	0.00	0.00	0.00	NA									
35104	1997	0.00	0.00	0.00	0.00	NA	NA								
35104	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
35104	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
35104	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
35104	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
35104	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
35104	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
35104	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
35104	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35104	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35104	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35104	2008	7,111.58	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35104	2009	0.00	14,000.00	0.00	14,000.00	NA	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%
35104	2010	0.00	0.00	0.00	0.00	NA	NA	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%
35104	2011	0.00	0.00	0.00	0.00	NA	NA	NA	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%
35104	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	196.86%	196.86%	196.86%	196.86%	196.86%	196.86%
35104	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	196.86%	196.86%	196.86%	196.86%	196.86%
35104	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	196.86%	196.86%	196.86%	196.86%
35200	1996	0.00	0.00	0.00	0.00	NA									
35200	1997	0.00	0.00	0.00	0.00	NA	NA								
35200	1998	1,565.00	0.00	0.00	0.00	0.00%	0.00%	0.00%							
35200	1999	15,727.00	0.00	30.00	(30.00)	-0.19%	-0.17%	-0.17%	-0.17%						
35200	2000	59,273.00	0.00	29,992.00	(29,992.00)	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%					
35200	2001	0.00	0.00	0.00	0.00	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%				
35200	2002	0.00	0.00	0.00	0.00	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%			
35200	2003	0.00	0.00	0.00	0.00	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%		
35200	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%	
35200	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%
35200	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%
35200	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%
35200	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	-50.60%	-40.03%
35200	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	-50.60%
35200	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35200	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35200	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35200	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35200	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35201	1996	0.00	0.00	0.00	0.00	NA									
35201	1997	0.00	0.00	0.00	0.00	NA	NA								
35201	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
35201	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
35201	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
35201	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
35201	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
35201	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
35201	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
35201	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35201	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35201	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35201	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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ATTACHMENT 1

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
35201	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35201	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35201	2011	9,187.28	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35201	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35201	2013	167,596.81	0.00	79,709.54	(79,709.54)	-47.56%	-47.56%	-45.09%	-45.09%	-45.09%	-45.09%	-45.09%	-45.09%	-45.09%	-45.09%
35201	2014	0.00	0.00	0.00	0.00	NA	-47.56%	-47.56%	-45.09%	-45.09%	-45.09%	-45.09%	-45.09%	-45.09%	-45.09%
35202	1996	0.00	0.00	0.00	0.00	NA									
35202	1997	0.00	0.00	0.00	0.00	NA	NA								
35202	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
35202	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
35202	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
35202	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
35202	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
35202	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
35202	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
35202	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35202	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35202	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35202	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35202	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35202	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35202	2011	22,030.17	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35202	2012	0.00	2,250.00	5,060.70	(2,810.70)	NA	-12.76%	-12.76%	-12.76%	-12.76%	-12.76%	-12.76%	-12.76%	-12.76%	-12.76%
35202	2013	17,870.44	0.00	28,554.79	(28,554.79)	-159.79%	-175.52%	-78.61%	-78.61%	-78.61%	-78.61%	-78.61%	-78.61%	-78.61%	-78.61%
35202	2014	12,688.12	0.00	54,928.68	(54,928.68)	-432.91%	-273.19%	-282.39%	-164.09%	-164.09%	-164.09%	-164.09%	-164.09%	-164.09%	-164.09%
352 Combine	1996	0.00	0.00	0.00	0.00	NA									
352 Combine	1997	0.00	0.00	0.00	0.00	NA	NA								
352 Combine	1998	1,565.00	0.00	0.00	0.00	0.00%	0.00%	0.00%							
352 Combine	1999	15,727.00	0.00	30.00	(30.00)	-0.19%	-0.17%	-0.17%	-0.17%						
352 Combine	2000	59,273.00	0.00	29,992.00	(29,992.00)	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%					
352 Combine	2001	0.00	0.00	0.00	0.00	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%				
352 Combine	2002	0.00	0.00	0.00	0.00	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%			
352 Combine	2003	0.00	0.00	0.00	0.00	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%		
352 Combine	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%	
352 Combine	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%	-39.21%
352 Combine	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%	-39.21%
352 Combine	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	-50.60%	-40.03%	-39.21%
352 Combine	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	-50.60%	-40.03%
352 Combine	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	-50.60%
352 Combine	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
352 Combine	2011	31,217.45	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
352 Combine	2012	0.00	2,250.00	5,060.70	(2,810.70)	NA	-9.00%	-9.00%	-9.00%	-9.00%	-9.00%	-9.00%	-9.00%	-9.00%	-9.00%
352 Combine	2013	185,467.25	0.00	108,264.33	(108,264.33)	-58.37%	-59.89%	-51.26%	-51.26%	-51.26%	-51.26%	-51.26%	-51.26%	-51.26%	-51.26%
352 Combine	2014	12,688.12	0.00	54,928.68	(54,928.68)	-432.91%	-82.36%	-83.77%	-72.37%	-72.37%	-72.37%	-72.37%	-72.37%	-72.37%	-72.37%
35301	1996	0.00	0.00	0.00	0.00	NA									
35301	1997	0.00	0.00	0.00	0.00	NA	NA								
35301	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
35301	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
35301	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
35301	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
35301	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
35301	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
35301	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
35301	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35301	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35301	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35301	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35301	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35301	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35301	2011	3.60	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35301	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35301	2013	0.00	0.00	15,227.00	(15,227.00)	NA	NA	-422972.22%	-422972.22%	-422972.22%	-422972.22%	-422972.22%	-422972.22%	-422972.22%	-422972.22%
35301	2014	0.00	0.00	0.00	0.00	NA	NA	NA	-422972.22%	-422972.22%	-422972.22%	-422972.22%	-422972.22%	-422972.22%	-422972.22%
35400	1996	0.00	0.00	0.00	0.00	NA									
35400	1997	0.00	0.00	0.00	0.00	NA	NA								
35400	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
35400	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
35400	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
35400	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
35400	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
35400	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
35400	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
35400	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35400	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35400	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35400	2008	29,359.45	0.00	6,316.66	(6,316.66)	-21.51%	-21.51%	-21.51%	-21.51%	-21.51%	-21.51%	-21.51%	-21.51%	-21.51%	-21.51%
35400	2009	18,288.00	16,500.00	3,263.56	13,236.44	72.38%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%
35400	2010	0.00	0.00	0.00	0.00	NA	72.38%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%
35400	2011	0.00	0.00	0.00	0.00	NA	NA	72.38%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%
35400	2012	98,736.60	0.00	6,771.68	(6,771.68)	-6.86%	-6.86%	-6.86%	5.52%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
35400	2013	0.00	0.00	0.00	0.00	NA	-6.86%	-6.86%	-6.86%	5.52%	0.10%	0.10%	0.10%	0.10%	0.10%
35400	2014	0.00	0.00	0.00	0.00	NA	NA	-6.86%	-6.86%	-6.86%	5.52%	0.10%	0.10%	0.10%	0.10%
35500	1996	0.00	0.00	0.00	0.00	NA									
35500	1997	0.00	0.00	0.00	0.00	NA	NA								
35500	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
35500	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
35500	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
35500	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
35500	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
35500	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
35500	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
35500	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35500	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35500	2007	46,368.72	0.00	1,951.61	(1,951.61)	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%
35500	2008	0.00	0.00	0.00	0.00	NA	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%
35500	2009	0.00	0.00	0.00	0.00	NA	NA	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%
35500	2010	0.00	0.00	0.00	0.00	NA	NA	NA	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%	-4.21%
35500	2011	1,598.80	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-4.07%	-4.07%	-4.07%	-4.07%	-4.07%	-4.07%
35500	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	-4.07%	-4.07%	-4.07%	-4.07%	-4.07%
35500	2013	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	-4.07%	-4.07%	-4.07%	-4.07%
35500	2014	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	-4.07%	-4.07%	-4.07%
35600	1996	0.00	0.00	0.00	0.00	NA									
35600	1997	0.00	0.00	0.00	0.00	NA	NA								
35600	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
35600	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						

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NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
35600	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
35600	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
35600	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
35600	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
35600	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
35600	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35600	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
35600	2007	78,270.05	0.00	2,205.12	(2,205.12)	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%
35600	2008	0.00	0.00	0.00	0.00	NA	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%
35600	2009	0.00	0.00	0.00	0.00	NA	NA	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%
35600	2010	0.00	0.00	0.00	0.00	NA	NA	NA	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%	-2.82%
35600	2011	869.16	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-2.79%	-2.79%	-2.79%	-2.79%	-2.79%	-2.79%
35600	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	-2.79%	-2.79%	-2.79%	-2.79%	-2.79%
35600	2013	10,502.64	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-2.46%	-2.46%	-2.46%	-2.46%
35600	2014	0.00	0.00	886.37	(886.37)	NA	-8.44%	-8.44%	-7.79%	-7.79%	-7.79%	-7.79%	-3.45%	-3.45%	-3.45%
36602	1996	0.00	0.00	0.00	0.00	NA									
36602	1997	0.00	0.00	0.00	0.00	NA	NA								
36602	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
36602	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
36602	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
36602	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
36602	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
36602	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
36602	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
36602	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36602	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36602	2007	0.00	0.00	19.54	(19.54)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36602	2008	16,176.74	0.00	0.00	0.00	0.00%	-0.12%	-0.12%	-0.12%	-0.12%	-0.12%	-0.12%	-0.12%	-0.12%	-0.12%
36602	2009	508.68	14,000.00	0.00	14,000.00	2752.22%	83.91%	83.79%	83.79%	83.79%	83.79%	83.79%	83.79%	83.79%	83.79%
36602	2010	0.00	0.00	14,567.15	(14,567.15)	NA	-111.49%	-3.40%	-3.52%	-3.52%	-3.52%	-3.52%	-3.52%	-3.52%	-3.52%
36602	2011	2,018.91	0.00	0.00	0.00	0.00%	-721.54%	-22.44%	-3.03%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%
36602	2012	0.00	0.00	0.00	0.00	NA	0.00%	-721.54%	-22.44%	-3.03%	-3.14%	-3.14%	-3.14%	-3.14%	-3.14%
36602	2013	0.00	0.00	0.00	0.00	NA	NA	0.00%	-721.54%	-22.44%	-3.03%	-3.14%	-3.14%	-3.14%	-3.14%
36602	2014	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	-721.54%	-22.44%	-3.03%	-3.14%	-3.14%	-3.14%
36603	1996	0.00	0.00	0.00	0.00	NA									
36603	1997	0.00	0.00	0.00	0.00	NA	NA								
36603	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
36603	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
36603	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
36603	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
36603	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
36603	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
36603	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
36603	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36603	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36603	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36603	2008	3,199.70	0.00	842.33	(842.33)	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%
36603	2009	0.00	0.00	0.00	0.00	NA	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%
36603	2010	0.00	0.00	0.00	0.00	NA	NA	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%	-26.33%
36603	2011	114.07	0.00	0.00	0.00	0.00%	0.00%	0.00%	-25.42%	-25.42%	-25.42%	-25.42%	-25.42%	-25.42%	-25.42%
36603	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	-25.42%	-25.42%	-25.42%	-25.42%	-25.42%	-25.42%
36603	2013	0.00	0.00	69.57	(69.57)	NA	NA	-60.99%	-60.99%	-60.99%	-27.52%	-27.52%	-27.52%	-27.52%	-27.52%
36603	2014	0.00	0.00	0.00	0.00	NA	NA	NA	-60.99%	-60.99%	-60.99%	-27.52%	-27.52%	-27.52%	-27.52%

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
366 Combine	1996	0.00	0.00	0.00	0.00	NA									
366 Combine	1997	0.00	0.00	0.00	0.00	NA	NA								
366 Combine	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
366 Combine	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
366 Combine	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
366 Combine	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
366 Combine	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
366 Combine	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
366 Combine	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
366 Combine	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
366 Combine	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
366 Combine	2007	0.00	0.00	19.54	(19.54)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
366 Combine	2008	19,376.44	0.00	842.33	(842.33)	-4.35%	-4.45%	-4.45%	-4.45%	-4.45%	-4.45%	-4.45%	-4.45%	-4.45%	-4.45%
366 Combine	2009	508.68	14,000.00	0.00	14,000.00	2752.22%	66.17%	66.07%	66.07%	66.07%	66.07%	66.07%	66.07%	66.07%	66.07%
366 Combine	2010	0.00	0.00	14,567.15	(14,567.15)	NA	-111.49%	-7.09%	-7.19%	-7.19%	-7.19%	-7.19%	-7.19%	-7.19%	-7.19%
366 Combine	2011	2,132.98	0.00	0.00	0.00	0.00%	-682.95%	-21.47%	-6.40%	-6.49%	-6.49%	-6.49%	-6.49%	-6.49%	-6.49%
366 Combine	2012	0.00	0.00	0.00	0.00	NA	0.00%	-682.95%	-21.47%	-6.40%	-6.49%	-6.49%	-6.49%	-6.49%	-6.49%
366 Combine	2013	0.00	0.00	69.57	(69.57)	NA	NA	-3.26%	-686.21%	-24.10%	-6.72%	-6.81%	-6.81%	-6.81%	-6.81%
366 Combine	2014	0.00	0.00	0.00	0.00	NA	NA	NA	-3.26%	-686.21%	-24.10%	-6.72%	-6.81%	-6.81%	-6.81%
36700	1996	8,002.00	0.00	12.00	(12.00)	-0.15%									
36700	1997	0.00	0.00	333.00	(333.00)	NA	-4.31%								
36700	1998	2,611.00	0.00	0.00	0.00	0.00%	-12.75%	-3.25%							
36700	1999	883.00	0.00	0.00	0.00	0.00%	0.00%	-9.53%	-3.00%						
36700	2000	7,957.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	-2.91%	-1.77%					
36700	2001	6,910.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-1.81%	-1.31%				
36700	2002	2,750.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	-1.58%	-1.19%			
36700	2003	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	-1.58%	-1.19%		
36700	2004	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	-1.58%	-1.19%	
36700	2005	22,519.00	0.00	28,499.08	(28,499.08)	-126.56%	-126.56%	-126.56%	-112.78%	-88.56%	-71.01%	-69.48%	-65.32%	-66.08%	-55.86%
36700	2006	0.00	0.00	0.00	0.00	NA	-126.56%	-126.56%	-126.56%	-112.78%	-88.56%	-71.01%	-69.48%	-65.32%	-66.08%
36700	2007	11,633.55	0.00	625.29	(625.29)	-5.37%	-5.37%	-85.28%	-85.28%	-85.28%	-78.92%	-66.47%	-56.26%	-55.31%	-52.70%
36700	2008	0.00	0.00	0.00	0.00	NA	-5.37%	-5.37%	-85.28%	-85.28%	-85.28%	-78.92%	-66.47%	-56.26%	-55.31%
36700	2009	0.00	0.00	0.00	0.00	NA	NA	-5.37%	-5.37%	-85.28%	-85.28%	-85.28%	-78.92%	-66.47%	-56.26%
36700	2010	0.00	0.00	0.00	0.00	NA	NA	NA	-5.37%	-5.37%	-85.28%	-85.28%	-85.28%	-78.92%	-66.47%
36700	2011	2,632.04	0.00	313.66	(313.66)	-11.92%	-11.92%	-11.92%	-11.92%	-6.58%	-6.58%	-80.03%	-80.03%	-80.03%	-74.46%
36700	2012	0.00	0.00	0.00	0.00	NA	-11.92%	-11.92%	-11.92%	-11.92%	-6.58%	-6.58%	-80.03%	-80.03%	-80.03%
36700	2013	14,934.31	0.00	0.00	0.00	0.00%	0.00%	-1.79%	-1.79%	-1.79%	-1.79%	-3.22%	-3.22%	-56.92%	-56.92%
36700	2014	252,543.59	0.00	1,189.08	(1,189.08)	-0.47%	-0.44%	-0.44%	-0.56%	-0.56%	-0.56%	-0.56%	-0.76%	-0.76%	-10.07%
36701	1996	0.00	0.00	0.00	0.00	NA									
36701	1997	0.00	0.00	0.00	0.00	NA	NA								
36701	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
36701	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
36701	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
36701	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
36701	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
36701	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
36701	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
36701	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36701	2006	2,765.11	0.00	5,223.87	(5,223.87)	-188.92%	-188.92%	-188.92%	-188.92%	-188.92%	-188.92%	-188.92%	-188.92%	-188.92%	-188.92%
36701	2007	32,746.54	0.00	7,085.52	(7,085.52)	-21.64%	-34.66%	-34.66%	-34.66%	-34.66%	-34.66%	-34.66%	-34.66%	-34.66%	-34.66%
36701	2008	5,150.74	0.00	19,867.43	(19,867.43)	-385.72%	-71.12%	-79.13%	-79.13%	-79.13%	-79.13%	-79.13%	-79.13%	-79.13%	-79.13%
36701	2009	193,189.22	0.00	4,538.26	(4,538.26)	-2.35%	-12.30%	-13.63%	-15.70%	-15.70%	-15.70%	-15.70%	-15.70%	-15.70%	-15.70%
36701	2010	13,352.93	0.00	546.98	(546.98)	-4.10%	-2.46%	-11.79%	-13.11%	-15.07%	-15.07%	-15.07%	-15.07%	-15.07%	-15.07%
36701	2011	205,128.55	0.00	80,449.24	(80,449.24)	-39.22%	-37.07%	-20.78%	-25.29%	-25.02%	-26.02%	-26.02%	-26.02%	-26.02%	-26.02%
36701	2012	9,558.36	0.00	71,136.41	(71,136.41)	-744.23%	-70.61%	-66.71%	-37.19%	-41.40%	-39.99%	-40.89%	-40.89%	-40.89%	-40.89%

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
36701	2013	328,937.64	0.00	142,895.07	(142,895.07)	-43.44%	-63.23%	-54.17%	-52.97%	-39.93%	-42.29%	-41.43%	-41.95%	-41.95%	-41.95%
36701	2014	803,047.47	0.00	146,710.81	(146,710.81)	-18.27%	-25.58%	-31.60%	-32.76%	-32.48%	-28.73%	-29.91%	-29.74%	-30.02%	-30.02%
367 Comb	1996	8,002.00	0.00	12.00	(12.00)	-0.15%									
367 Comb	1997	0.00	0.00	333.00	(333.00)	NA	-4.31%								
367 Comb	1998	2,611.00	0.00	0.00	0.00	0.00%	-12.75%	-3.25%							
367 Comb	1999	883.00	0.00	0.00	0.00	0.00%	0.00%	-9.53%	-3.00%						
367 Comb	2000	7,957.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	-2.91%	-1.77%					
367 Comb	2001	6,910.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-1.81%	-1.31%				
367 Comb	2002	2,750.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	-1.58%	-1.19%			
367 Comb	2003	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	-1.58%	-1.19%		
367 Comb	2004	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	-1.58%	-1.19%	
367 Comb	2005	22,519.00	0.00	28,499.08	(28,499.08)	-126.56%	-126.56%	-126.56%	-112.78%	-88.56%	-71.01%	-69.48%	-65.32%	-66.08%	-55.86%
367 Comb	2006	2,765.11	0.00	5,223.87	(5,223.87)	-188.92%	-133.38%	-133.38%	-133.38%	-120.29%	-96.51%	-78.61%	-77.02%	-72.69%	-73.40%
367 Comb	2007	44,380.09	0.00	7,710.81	(7,710.81)	-17.37%	-27.44%	-59.48%	-59.48%	-59.48%	-57.22%	-52.23%	-47.47%	-47.00%	-45.64%
367 Comb	2008	5,150.74	0.00	19,867.43	(19,867.43)	-385.72%	-55.68%	-62.72%	-81.94%	-81.94%	-81.94%	-79.03%	-72.57%	-66.32%	-65.69%
367 Comb	2009	193,189.22	0.00	4,538.26	(4,538.26)	-2.35%	-12.30%	-13.23%	-15.21%	-24.57%	-24.57%	-24.57%	-24.32%	-23.71%	-23.05%
367 Comb	2010	13,352.93	0.00	546.98	(546.98)	-4.10%	-2.46%	-11.79%	-12.76%	-14.64%	-23.60%	-23.60%	-23.60%	-23.37%	-22.81%
367 Comb	2011	207,760.59	0.00	80,762.90	(80,762.90)	-38.87%	-36.77%	-20.72%	-25.20%	-24.45%	-25.43%	-30.08%	-30.08%	-30.08%	-29.92%
367 Comb	2012	9,558.36	0.00	71,136.41	(71,136.41)	-744.23%	-69.90%	-66.09%	-37.04%	-41.22%	-38.99%	-39.86%	-43.77%	-43.77%	-43.77%
367 Comb	2013	343,871.95	0.00	142,895.07	(142,895.07)	-41.55%	-60.56%	-52.53%	-51.40%	-39.06%	-41.37%	-40.07%	-40.57%	-42.87%	-42.87%
367 Comb	2014	1,055,591.06	0.00	147,899.89	(147,899.89)	-14.01%	-20.78%	-25.69%	-27.38%	-27.19%	-24.56%	-25.58%	-25.38%	-25.62%	-26.82%
36900	1996	0.00	0.00	191.00	(191.00)	NA									
36900	1997	0.00	0.00	0.00	0.00	NA	NA								
36900	1998	13,523.00	0.00	77.00	(77.00)	-0.57%	-0.57%	-1.98%							
36900	1999	0.00	0.00	0.00	0.00	NA	-0.57%	-0.57%	-1.98%						
36900	2000	0.00	0.00	0.00	0.00	NA	NA	-0.57%	-0.57%	-1.98%					
36900	2001	2,183.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%				
36900	2002	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%			
36900	2003	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%		
36900	2004	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%	
36900	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%
36900	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%
36900	2007	0.00	0.00	1,251.20	(1,251.20)	NA	NA	NA	NA	NA	NA	-57.32%	-57.32%	-57.32%	-8.46%
36900	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	-57.32%	-57.32%	-57.32%
36900	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	-57.32%	-57.32%
36900	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	-57.32%
36900	2011	62,139.52	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-2.01%	-2.01%	-2.01%	-2.01%	-2.01%	-2.01%
36900	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	-2.01%	-2.01%	-2.01%	-2.01%	-2.01%
36900	2013	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	-2.01%	-2.01%	-2.01%	-2.01%
36900	2014	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	-2.01%	-2.01%	-2.01%
36901	1996	0.00	0.00	0.00	0.00	NA									
36901	1997	0.00	0.00	0.00	0.00	NA	NA								
36901	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
36901	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
36901	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
36901	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
36901	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
36901	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
36901	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
36901	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36901	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36901	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
36901	2008	34,336.56	0.00	16,586.69	(16,586.69)	-48.31%	-48.31%	-48.31%	-48.31%	-48.31%	-48.31%	-48.31%	-48.31%	-48.31%	-48.31%

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
36901	2009	135,215.89	0.00	3,139.41	(3,139.41)	-2.32%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%
36901	2010	0.00	0.00	0.00	0.00	NA	-2.32%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%
36901	2011	0.00	0.00	0.00	0.00	NA	NA	-2.32%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%
36901	2012	132.12	0.00	0.00	0.00	0.00%	0.00%	0.00%	-2.32%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%	-11.63%
36901	2013	804.56	0.00	1,612.76	(1,612.76)	-200.45%	-172.18%	-172.18%	-172.18%	-3.49%	-12.52%	-12.52%	-12.52%	-12.52%	-12.52%
36901	2014	2,501.82	0.00	0.00	0.00	0.00%	-48.78%	-46.90%	-46.90%	-46.90%	-3.43%	-12.34%	-12.34%	-12.34%	-12.34%
369 Combine	1996	0.00	0.00	191.00	(191.00)	NA									
369 Combine	1997	0.00	0.00	0.00	0.00	NA	NA								
369 Combine	1998	13,523.00	0.00	77.00	(77.00)	-0.57%	-0.57%	-1.98%							
369 Combine	1999	0.00	0.00	0.00	0.00	NA	-0.57%	-0.57%	-1.98%						
369 Combine	2000	0.00	0.00	0.00	0.00	NA	NA	-0.57%	-0.57%	-1.98%					
369 Combine	2001	2,183.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%				
369 Combine	2002	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%			
369 Combine	2003	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%		
369 Combine	2004	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%	
369 Combine	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%	-1.71%
369 Combine	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	-0.49%	-0.49%
369 Combine	2007	0.00	0.00	1,251.20	(1,251.20)	NA	NA	NA	NA	NA	NA	-57.32%	-57.32%	-57.32%	-8.46%
369 Combine	2008	34,336.56	0.00	16,586.69	(16,586.69)	-48.31%	-51.95%	-51.95%	-51.95%	-51.95%	-51.95%	-51.95%	-48.84%	-48.84%	-48.84%
369 Combine	2009	135,215.89	0.00	3,139.41	(3,139.41)	-2.32%	-11.63%	-12.37%	-12.37%	-12.37%	-12.37%	-12.37%	-12.37%	-12.21%	-12.21%
369 Combine	2010	0.00	0.00	0.00	0.00	NA	-2.32%	-11.63%	-12.37%	-12.37%	-12.37%	-12.37%	-12.37%	-12.37%	-12.21%
369 Combine	2011	62,139.52	0.00	0.00	0.00	0.00%	0.00%	-1.59%	-8.51%	-9.05%	-9.05%	-9.05%	-9.05%	-9.05%	-9.05%
369 Combine	2012	132.12	0.00	0.00	0.00	0.00%	0.00%	0.00%	-1.59%	-8.51%	-9.05%	-9.05%	-9.05%	-9.05%	-9.05%
369 Combine	2013	804.56	0.00	1,612.76	(1,612.76)	-200.45%	-172.18%	-2.56%	-2.56%	-2.40%	-9.17%	-9.71%	-9.71%	-9.71%	-9.71%
369 Combine	2014	2,501.82	0.00	0.00	0.00	0.00%	-48.78%	-46.90%	-2.46%	-2.46%	-2.37%	-9.08%	-9.61%	-9.61%	-9.61%
37402	1996	0.00	0.00	0.00	0.00	NA									
37402	1997	0.00	0.00	0.00	0.00	NA	NA								
37402	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37402	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
37402	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
37402	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
37402	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
37402	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
37402	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
37402	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37402	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37402	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37402	2008	16.80	8.25	0.00	8.25	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%
37402	2009	0.00	0.00	0.00	0.00	NA	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%
37402	2010	0.00	0.00	0.00	0.00	NA	NA	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%
37402	2011	0.00	0.00	0.00	0.00	NA	NA	NA	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%
37402	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	49.11%	49.11%	49.11%	49.11%	49.11%	49.11%
37402	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	49.11%	49.11%	49.11%	49.11%	49.11%
37402	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	49.11%	49.11%	49.11%	49.11%
37500	1996	0.00	0.00	0.00	0.00	NA									
37500	1997	0.00	0.00	0.00	0.00	NA	NA								
37500	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37500	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
37500	2000	4,190.00	0.00	3,054.00	(3,054.00)	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%					
37500	2001	0.00	0.00	0.00	0.00	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%				
37500	2002	0.00	0.00	0.00	0.00	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%			
37500	2003	0.00	0.00	0.00	0.00	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%		
37500	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%	

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
37500	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%
37500	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%
37500	2007	0.00	0.00	41.51	(41.51)	NA	NA	NA	NA	NA	NA	NA	-73.88%	-73.88%	-73.88%
37500	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	-73.88%	-73.88%
37500	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	-73.88%
37500	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37500	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37500	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37500	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37500	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37501	1996	0.00	0.00	0.00	0.00	NA									
37501	1997	0.00	0.00	0.00	0.00	NA	NA								
37501	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37501	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
37501	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
37501	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
37501	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
37501	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
37501	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
37501	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37501	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37501	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37501	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37501	2009	2,802.98	0.00	368.76	(368.76)	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%
37501	2010	0.00	0.00	0.00	0.00	NA	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%
37501	2011	0.00	0.00	0.00	0.00	NA	NA	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%
37501	2012	0.00	0.00	0.00	0.00	NA	NA	NA	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%	-13.16%
37501	2013	1,005.61	0.00	1,098.55	(1,098.55)	-109.24%	-109.24%	-109.24%	-109.24%	-38.53%	-38.53%	-38.53%	-38.53%	-38.53%	-38.53%
37501	2014	682.76	0.00	774.33	(774.33)	-113.41%	-110.93%	-110.93%	-110.93%	-110.93%	-49.91%	-49.91%	-49.91%	-49.91%	-49.91%
375 Combine	1996	0.00	0.00	0.00	0.00	NA									
375 Combine	1997	0.00	0.00	0.00	0.00	NA	NA								
375 Combine	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
375 Combine	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
375 Combine	2000	4,190.00	0.00	3,054.00	(3,054.00)	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%					
375 Combine	2001	0.00	0.00	0.00	0.00	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%				
375 Combine	2002	0.00	0.00	0.00	0.00	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%			
375 Combine	2003	0.00	0.00	0.00	0.00	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%		
375 Combine	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%	
375 Combine	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%	-72.89%
375 Combine	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-72.89%	-72.89%	-72.89%	-72.89%
375 Combine	2007	0.00	0.00	41.51	(41.51)	NA	NA	NA	NA	NA	NA	NA	-73.88%	-73.88%	-73.88%
375 Combine	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	-73.88%	-73.88%
375 Combine	2009	2,802.98	0.00	368.76	(368.76)	-13.16%	-13.16%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%	-49.54%
375 Combine	2010	0.00	0.00	0.00	0.00	NA	-13.16%	-13.16%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%
375 Combine	2011	0.00	0.00	0.00	0.00	NA	NA	-13.16%	-13.16%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%
375 Combine	2012	0.00	0.00	0.00	0.00	NA	NA	NA	-13.16%	-13.16%	-14.64%	-14.64%	-14.64%	-14.64%	-14.64%
375 Combine	2013	1,005.61	0.00	1,098.55	(1,098.55)	-109.24%	-109.24%	-109.24%	-109.24%	-38.53%	-38.53%	-39.62%	-39.62%	-39.62%	-39.62%
375 Combine	2014	682.76	0.00	774.33	(774.33)	-113.41%	-110.93%	-110.93%	-110.93%	-110.93%	-49.91%	-49.91%	-50.83%	-50.83%	-50.83%
37600	1996	55,351.00	67,854.62	4,609.00	63,245.62	114.26%									
37600	1997	197,090.00	0.00	251,775.00	(251,775.00)	-127.75%	-74.68%								
37600	1998	121,727.00	6,321.00	2,709.00	3,612.00	2.97%	-77.84%	-49.42%							
37600	1999	143,666.00	0.00	25,600.00	(25,600.00)	-17.82%	-8.29%	-59.19%	-40.65%						
37600	2000	67,723.00	0.00	80,330.00	(80,330.00)	-118.62%	-50.11%	-30.72%	-66.78%	-49.67%					

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37600	2001	180,309.00	0.00	100,246.00	(100,246.00)	-55.60%	-72.80%	-52.64%	-39.45%	-63.95%	-51.07%				
37600	2002	112,370.00	0.00	20,416.00	(20,416.00)	-18.17%	-41.23%	-55.77%	-44.95%	-35.63%	-57.69%	-46.86%			
37600	2003	112,104.00	0.00	42,202.00	(42,202.00)	-37.65%	-27.90%	-40.23%	-51.47%	-43.62%	-35.94%	-55.29%	-45.81%		
37600	2004	63,595.00	0.00	50,731.00	(50,731.00)	-79.77%	-52.89%	-39.35%	-45.60%	-54.83%	-47.01%	-39.42%	-56.85%	-47.86%	
37600	2005	305,582.00	0.00	32,095.27	(32,095.27)	-10.50%	-22.44%	-25.98%	-24.50%	-31.74%	-38.73%	-35.68%	-31.43%	-45.99%	-39.47%
37600	2006	(40,282.85)	0.00	8,347.43	(8,347.43)	20.72%	-15.24%	-27.72%	-30.24%	-27.79%	-34.63%	-41.72%	-38.09%	-33.40%	-48.12%
37600	2007	290,162.96	0.00	149,699.34	(149,699.34)	-51.59%	-63.25%	-34.23%	-38.91%	-38.72%	-35.98%	-39.43%	-44.35%	-41.26%	-37.29%
37600	2008	1,892.89	0.00	1,110.43	(1,110.43)	-58.66%	-51.64%	-63.21%	-34.31%	-38.97%	-38.77%	-36.03%	-39.47%	-44.37%	-41.29%
37600	2009	101,013.50	0.00	4,299.32	(4,299.32)	-4.26%	-5.26%	-39.46%	-46.33%	-29.70%	-34.11%	-34.59%	-32.64%	-36.31%	-40.98%
37600	2010	20,731.57	0.00	309.01	(309.01)	-1.49%	-3.79%	-4.63%	-37.56%	-43.84%	-28.84%	-33.20%	-33.78%	-31.97%	-35.68%
37600	2011	18,608.94	0.00	64.79	(64.79)	-0.35%	-0.95%	-3.33%	-4.07%	-35.96%	-41.78%	-28.08%	-32.40%	-33.07%	-31.37%
37600	2012	697,633.25	0.00	24,624.56	(24,624.56)	-3.53%	-3.45%	-3.39%	-3.50%	-3.62%	-15.94%	-17.29%	-15.81%	-18.59%	-19.95%
37600	2013	8,566.12	0.00	6,505.50	(6,505.50)	-75.94%	-4.41%	-4.30%	-4.23%	-4.23%	-4.35%	-16.39%	-17.75%	-16.17%	-18.93%
37600	2014	1,192,398.37	0.00	35,179.02	(35,179.02)	-2.95%	-3.47%	-3.49%	-3.46%	-3.44%	-3.48%	-3.53%	-9.51%	-10.05%	-10.10%
37601	1996	0.00	0.00	0.00	0.00	NA									
37601	1997	0.00	0.00	0.00	0.00	NA	NA								
37601	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37601	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
37601	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
37601	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
37601	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
37601	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
37601	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
37601	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37601	2006	244,942.41	0.00	351,638.67	(351,638.67)	-143.56%	-143.56%	-143.56%	-143.56%	-143.56%	-143.56%	-143.56%	-143.56%	-143.56%	-143.56%
37601	2007	1,361,933.19	0.00	95,989.92	(95,989.92)	-7.05%	-27.86%	-27.86%	-27.86%	-27.86%	-27.86%	-27.86%	-27.86%	-27.86%	-27.86%
37601	2008	963,544.19	0.00	128,492.44	(128,492.44)	-13.34%	-9.65%	-22.41%	-22.41%	-22.41%	-22.41%	-22.41%	-22.41%	-22.41%	-22.41%
37601	2009	180,458.40	0.00	15,880.40	(15,880.40)	-8.80%	-12.62%	-9.59%	-21.52%	-21.52%	-21.52%	-21.52%	-21.52%	-21.52%	-21.52%
37601	2010	1,118,381.61	18,212.80	267,326.95	(249,114.15)	-22.27%	-20.40%	-17.39%	-13.51%	-21.74%	-21.74%	-21.74%	-21.74%	-21.74%	-21.74%
37601	2011	402,026.97	0.00	131,713.87	(131,713.87)	-32.76%	-25.05%	-23.32%	-19.71%	-15.43%	-22.78%	-22.78%	-22.78%	-22.78%	-22.78%
37601	2012	1,204,856.02	0.00	186,641.93	(186,641.93)	-15.49%	-19.81%	-20.82%	-20.08%	-18.40%	-15.44%	-21.17%	-21.17%	-21.17%	-21.17%
37601	2013	1,859,842.35	0.00	378,030.10	(378,030.10)	-20.33%	-18.43%	-20.09%	-20.62%	-20.17%	-19.02%	-16.72%	-20.96%	-20.96%	-20.96%
37601	2014	1,714,980.20	0.00	403,146.39	(403,146.39)	-23.51%	-21.85%	-20.25%	-21.22%	-21.41%	-21.06%	-20.06%	-18.04%	-21.44%	-21.44%
37602	1996	0.00	0.00	0.00	0.00	NA									
37602	1997	0.00	0.00	0.00	0.00	NA	NA								
37602	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37602	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
37602	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
37602	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
37602	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
37602	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
37602	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
37602	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37602	2006	49,623.79	0.00	120,053.43	(120,053.43)	-241.93%	-241.93%	-241.93%	-241.93%	-241.93%	-241.93%	-241.93%	-241.93%	-241.93%	-241.93%
37602	2007	33,519.67	0.00	6,877.93	(6,877.93)	-20.52%	-152.67%	-152.67%	-152.67%	-152.67%	-152.67%	-152.67%	-152.67%	-152.67%	-152.67%
37602	2008	40,050.64	0.00	8,218.83	(8,218.83)	-20.52%	-20.52%	-109.71%	-109.71%	-109.71%	-109.71%	-109.71%	-109.71%	-109.71%	-109.71%
37602	2009	17,782.95	0.00	2,167.03	(2,167.03)	-12.19%	-17.96%	-18.90%	-97.40%	-97.40%	-97.40%	-97.40%	-97.40%	-97.40%	-97.40%
37602	2010	44,183.23	0.00	20,406.10	(20,406.10)	-46.19%	-36.43%	-30.18%	-27.79%	-85.18%	-85.18%	-85.18%	-85.18%	-85.18%	-85.18%
37602	2011	58,128.12	0.00	35,842.92	(35,842.92)	-61.66%	-54.98%	-48.64%	-41.61%	-37.96%	-79.56%	-79.56%	-79.56%	-79.56%	-79.56%
37602	2012	152,150.97	0.00	119,495.68	(119,495.68)	-78.54%	-73.87%	-69.07%	-65.35%	-59.60%	-55.81%	-79.17%	-79.17%	-79.17%	-79.17%
37602	2013	155,926.67	0.00	137,955.96	(137,955.96)	-88.47%	-83.57%	-80.09%	-76.44%	-73.77%	-69.22%	-65.96%	-81.80%	-81.80%	-81.80%
37602	2014	223,390.05	0.00	102,075.91	(102,075.91)	-45.69%	-63.28%	-67.65%	-67.06%	-65.60%	-64.14%	-61.62%	-59.72%	-71.39%	-71.39%
37601&02	1996	0.00	0.00	0.00	0.00	NA									

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
37601&02	1997	0.00	0.00	0.00	0.00	NA	NA								
37601&02	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37601&02	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
37601&02	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
37601&02	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
37601&02	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
37601&02	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
37601&02	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
37601&02	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37601&02	2006	294,566.20	0.00	471,692.10	(471,692.10)	-160.13%	-160.13%	-160.13%	-160.13%	-160.13%	-160.13%	-160.13%	-160.13%	-160.13%	-160.13%
37601&02	2007	1,395,452.86	0.00	102,867.85	(102,867.85)	-7.37%	-34.00%	-34.00%	-34.00%	-34.00%	-34.00%	-34.00%	-34.00%	-34.00%	-34.00%
37601&02	2008	1,003,594.83	0.00	136,711.27	(136,711.27)	-13.62%	-9.99%	-26.41%	-26.41%	-26.41%	-26.41%	-26.41%	-26.41%	-26.41%	-26.41%
37601&02	2009	198,241.35	0.00	18,047.43	(18,047.43)	-9.10%	-12.88%	-9.92%	-25.22%	-25.22%	-25.22%	-25.22%	-25.22%	-25.22%	-25.22%
37601&02	2010	1,162,564.84	18,212.80	287,733.05	(269,520.25)	-23.18%	-21.13%	-17.94%	-14.02%	-24.64%	-24.64%	-24.64%	-24.64%	-24.64%	-24.64%
37601&02	2011	460,155.09	0.00	167,556.79	(167,556.79)	-36.41%	-26.93%	-24.99%	-20.95%	-16.46%	-25.84%	-25.84%	-25.84%	-25.84%	-25.84%
37601&02	2012	1,357,006.99	0.00	306,137.61	(306,137.61)	-22.56%	-26.07%	-24.94%	-23.95%	-21.47%	-17.95%	-25.08%	-25.08%	-25.08%	-25.08%
37601&02	2013	2,015,769.02	0.00	515,986.06	(515,986.06)	-25.60%	-24.38%	-25.82%	-25.21%	-24.59%	-22.82%	-19.98%	-25.21%	-25.21%	-25.21%
37601&02	2014	1,938,370.25	0.00	505,222.30	(505,222.30)	-26.06%	-25.83%	-24.99%	-25.90%	-25.45%	-24.99%	-23.59%	-21.22%	-25.38%	-25.38%
376 Combine	1996	55,351.00	67,854.62	4,609.00	63,245.62	114.26%									
376 Combine	1997	197,090.00	0.00	251,775.00	(251,775.00)	-127.75%	-74.68%								
376 Combine	1998	121,727.00	6,321.00	2,709.00	3,612.00	2.97%	-77.84%	-49.42%							
376 Combine	1999	143,666.00	0.00	25,600.00	(25,600.00)	-17.82%	-8.29%	-59.19%	-40.65%						
376 Combine	2000	67,723.00	0.00	80,330.00	(80,330.00)	-118.62%	-50.11%	-30.72%	-66.78%	-49.67%					
376 Combine	2001	180,309.00	0.00	100,246.00	(100,246.00)	-55.60%	-72.80%	-52.64%	-39.45%	-63.95%	-51.07%				
376 Combine	2002	112,370.00	0.00	20,416.00	(20,416.00)	-18.17%	-41.23%	-55.77%	-44.95%	-35.63%	-57.69%	-46.86%			
376 Combine	2003	112,104.00	0.00	42,202.00	(42,202.00)	-37.65%	-27.90%	-40.23%	-51.47%	-43.62%	-35.94%	-55.29%	-45.81%		
376 Combine	2004	63,595.00	0.00	50,731.00	(50,731.00)	-79.77%	-52.89%	-39.35%	-45.60%	-54.83%	-47.01%	-39.42%	-56.85%	-47.86%	
376 Combine	2005	305,582.00	0.00	32,095.27	(32,095.27)	-10.50%	-22.44%	-25.98%	-24.50%	-31.74%	-38.73%	-35.68%	-31.43%	-45.99%	-39.47%
376 Combine	2006	254,283.35	0.00	480,039.53	(480,039.53)	-188.78%	-91.47%	-90.28%	-82.26%	-73.77%	-70.58%	-73.55%	-67.09%	-60.83%	-69.29%
376 Combine	2007	1,685,615.82	0.00	252,567.19	(252,567.19)	-14.98%	-37.77%	-34.06%	-35.31%	-35.42%	-34.66%	-36.05%	-38.06%	-37.06%	-35.47%
376 Combine	2008	1,005,487.72	0.00	137,821.70	(137,821.70)	-13.71%	-14.51%	-29.55%	-27.76%	-28.76%	-29.05%	-28.70%	-30.01%	-31.59%	-31.09%
376 Combine	2009	299,254.85	0.00	22,346.75	(22,346.75)	-7.47%	-12.28%	-13.80%	-27.52%	-26.05%	-27.00%	-27.32%	-27.05%	-28.33%	-29.83%
376 Combine	2010	1,183,296.41	18,212.80	288,042.06	(269,829.26)	-22.80%	-19.71%	-17.28%	-16.35%	-26.26%	-25.24%	-25.96%	-26.23%	-26.05%	-27.07%
376 Combine	2011	478,764.03	0.00	167,621.58	(167,621.58)	-35.01%	-26.32%	-23.44%	-20.14%	-18.27%	-27.11%	-26.14%	-26.78%	-27.01%	-26.83%
376 Combine	2012	2,054,640.24	0.00	330,762.17	(330,762.17)	-16.10%	-19.67%	-20.67%	-19.69%	-18.49%	-17.61%	-23.86%	-23.30%	-23.79%	-24.00%
376 Combine	2013	2,024,335.14	0.00	522,491.56	(522,491.56)	-25.81%	-20.92%	-22.40%	-22.48%	-21.74%	-20.59%	-19.51%	-24.30%	-23.85%	-24.23%
376 Combine	2014	3,130,768.62	0.00	540,401.32	(540,401.32)	-17.26%	-20.62%	-19.33%	-20.31%	-20.64%	-20.21%	-19.57%	-18.92%	-22.48%	-22.19%
37800	1996	0.00	0.00	39.00	(39.00)	NA									
37800	1997	0.00	0.00	0.00	0.00	NA	NA								
37800	1998	375.00	0.00	23.00	(23.00)	-6.13%	-6.13%	-16.53%							
37800	1999	917.00	0.00	0.00	0.00	0.00%	-1.78%	-1.78%	-4.80%						
37800	2000	0.00	0.00	0.00	0.00	NA	0.00%	-1.78%	-1.78%	-4.80%					
37800	2001	0.00	0.00	0.00	0.00	NA	NA	0.00%	-1.78%	-1.78%	-4.80%				
37800	2002	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	-1.78%	-1.78%	-4.80%			
37800	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	-1.78%	-1.78%	-4.80%		
37800	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	-1.78%	-1.78%	-4.80%	
37800	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	0.00%	-1.78%	-1.78%	-4.80%
37800	2006	12,626.52	0.00	7,595.24	(7,595.24)	-60.15%	-60.15%	-60.15%	-60.15%	-60.15%	-60.15%	-60.15%	-56.08%	-54.73%	-54.73%
37800	2007	24,754.08	0.00	53,949.01	(53,949.01)	-217.94%	-164.64%	-164.64%	-164.64%	-164.64%	-164.64%	-164.64%	-164.64%	-160.70%	-159.20%
37800	2008	42,840.62	0.00	8,927.04	(8,927.04)	-20.84%	-93.02%	-87.85%	-87.85%	-87.85%	-87.85%	-87.85%	-87.85%	-87.85%	-86.85%
37800	2009	77,929.56	0.00	12,615.95	(12,615.95)	-16.19%	-17.84%	-51.88%	-52.54%	-52.54%	-52.54%	-52.54%	-52.54%	-52.54%	-52.54%
37800	2010	40,104.33	(5,555.50)	(51,950.73)	46,395.23	115.69%	28.62%	15.45%	-15.67%	-18.51%	-18.51%	-18.51%	-18.51%	-18.51%	-18.51%
37800	2011	6,999.33	0.00	16,667.76	(16,667.76)	-238.13%	63.11%	13.69%	4.88%	-23.76%	-26.00%	-26.00%	-26.00%	-26.00%	-26.00%
37800	2012	18,827.60	0.00	2,730.58	(2,730.58)	-14.50%	-75.11%	40.95%	10.00%	2.92%	-22.93%	-25.03%	-25.03%	-25.03%	-25.03%
37800	2013	8,476.32	0.00	12,585.69	(12,585.69)	-148.48%	-56.10%	-93.24%	19.37%	1.18%	-3.65%	-27.77%	-29.53%	-29.53%	-29.53%

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
37800	2014	57,926.47	0.00	4,840.61	(4,840.61)	-8.36%	-26.24%	-23.65%	-39.93%	7.23%	-1.45%	-4.73%	-23.72%	-25.31%	-25.31%
37900	1996	0.00	0.00	0.00	0.00	NA									
37900	1997	0.00	0.00	0.00	0.00	NA	NA								
37900	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37900	1999	1,547.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%						
37900	2000	12,823.00	0.00	2,112.00	(2,112.00)	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%					
37900	2001	0.00	0.00	0.00	0.00	NA	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%				
37900	2002	0.00	0.00	0.00	0.00	NA	NA	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%			
37900	2003	0.00	0.00	0.00	0.00	NA	NA	NA	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%		
37900	2004	302.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-16.09%	-14.39%	-14.39%	-14.39%	-14.39%	
37900	2005	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	-16.09%	-14.39%	-14.39%	-14.39%	-14.39%
37900	2006	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	-16.09%	-14.39%	-14.39%	-14.39%
37900	2007	0.00	0.00	502.42	(502.42)	NA	NA	NA	-166.36%	-166.36%	-166.36%	-166.36%	-19.92%	-17.82%	-17.82%
37900	2008	737.89	0.00	867.44	(867.44)	-117.56%	-185.65%	-185.65%	-185.65%	-131.73%	-131.73%	-131.73%	-131.73%	-25.12%	-22.59%
37900	2009	17,655.19	0.00	9.46	(9.46)	-0.05%	-4.77%	-7.50%	-7.50%	-7.50%	-7.38%	-7.38%	-7.38%	-7.38%	-11.08%
37900	2010	12,988.61	0.00	144.68	(144.68)	-1.11%	-0.50%	-3.26%	-4.86%	-4.86%	-4.86%	-4.81%	-4.81%	-4.81%	-4.81%
37900	2011	58,535.80	0.00	682.55	(682.55)	-1.17%	-1.16%	-0.94%	-1.90%	-2.45%	-2.45%	-2.45%	-2.45%	-2.45%	-2.45%
37900	2012	0.00	0.00	(7.46)	7.46	NA	-1.15%	-1.15%	-0.93%	-1.89%	-2.45%	-2.45%	-2.45%	-2.44%	-2.44%
37900	2013	0.00	0.00	11,474.75	(11,474.75)	NA	NA	-20.76%	-17.19%	-13.80%	-14.65%	-15.21%	-15.21%	-15.21%	-15.16%
37900	2014	9,769.19	0.00	1,891.08	(1,891.08)	-19.36%	-136.82%	-136.74%	-20.56%	-17.45%	-14.35%	-15.11%	-15.61%	-15.61%	-15.61%
37905	1996	0.00	0.00	0.00	0.00	NA									
37905	1997	0.00	0.00	0.00	0.00	NA	NA								
37905	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
37905	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
37905	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
37905	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
37905	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
37905	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
37905	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
37905	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37905	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37905	2007	0.00	0.00	1,427.19	(1,427.19)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
37905	2008	24,696.22	0.00	945.85	(945.85)	-3.83%	-9.61%	-9.61%	-9.61%	-9.61%	-9.61%	-9.61%	-9.61%	-9.61%	-9.61%
37905	2009	123,047.90	0.00	6,102.71	(6,102.71)	-4.96%	-4.77%	-5.74%	-5.74%	-5.74%	-5.74%	-5.74%	-5.74%	-5.74%	-5.74%
37905	2010	5,467.88	0.00	7,060.85	(7,060.85)	-129.13%	-10.24%	-9.21%	-10.14%	-10.14%	-10.14%	-10.14%	-10.14%	-10.14%	-10.14%
37905	2011	24,565.78	0.00	16,849.25	(16,849.25)	-68.59%	-79.61%	-19.61%	-17.41%	-18.22%	-18.22%	-18.22%	-18.22%	-18.22%	-18.22%
37905	2012	9,710.15	0.00	2,478.88	(2,478.88)	-25.53%	-56.39%	-66.40%	-19.96%	-17.83%	-18.60%	-18.60%	-18.60%	-18.60%	-18.60%
37905	2013	10,272.40	0.00	18,042.42	(18,042.42)	-175.64%	-102.70%	-83.89%	-88.83%	-29.20%	-26.03%	-26.75%	-26.75%	-26.75%	-26.75%
37905	2014	9,158.09	0.00	1,287.64	(1,287.64)	-14.06%	-99.48%	-74.84%	-71.98%	-77.26%	-28.44%	-25.50%	-26.19%	-26.19%	-26.19%
379 Combine	1996	0.00	0.00	0.00	0.00	NA									
379 Combine	1997	0.00	0.00	0.00	0.00	NA	NA								
379 Combine	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
379 Combine	1999	1,547.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%						
379 Combine	2000	12,823.00	0.00	2,112.00	(2,112.00)	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%					
379 Combine	2001	0.00	0.00	0.00	0.00	NA	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%				
379 Combine	2002	0.00	0.00	0.00	0.00	NA	NA	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%			
379 Combine	2003	0.00	0.00	0.00	0.00	NA	NA	NA	-16.47%	-14.70%	-14.70%	-14.70%	-14.70%		
379 Combine	2004	302.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-16.09%	-14.39%	-14.39%	-14.39%	-14.39%	
379 Combine	2005	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	-16.09%	-14.39%	-14.39%	-14.39%	-14.39%
379 Combine	2006	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	-16.09%	-14.39%	-14.39%	-14.39%
379 Combine	2007	0.00	0.00	1,929.61	(1,929.61)	NA	NA	NA	-638.94%	-638.94%	-638.94%	-638.94%	-30.79%	-27.55%	-27.55%
379 Combine	2008	25,434.11	0.00	1,813.29	(1,813.29)	-7.13%	-14.72%	-14.72%	-14.72%	-14.54%	-14.54%	-14.54%	-14.54%	-15.18%	-14.60%
379 Combine	2009	140,703.09	0.00	6,112.17	(6,112.17)	-4.34%	-4.77%	-5.93%	-5.93%	-5.93%	-5.92%	-5.92%	-5.92%	-5.92%	-6.68%

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
379 Combine	2010	18,456.49	0.00	7,205.53	(7,205.53)	-39.04%	-8.37%	-8.20%	-9.24%	-9.24%	-9.24%	-9.23%	-9.23%	-9.23%	-9.23%
379 Combine	2011	83,101.58	0.00	17,531.80	(17,531.80)	-21.10%	-24.36%	-12.73%	-12.20%	-12.92%	-12.92%	-12.92%	-12.91%	-12.91%	-12.91%
379 Combine	2012	9,710.15	0.00	2,471.42	(2,471.42)	-25.45%	-21.55%	-24.45%	-13.22%	-12.67%	-13.36%	-13.36%	-13.36%	-13.35%	-13.35%
379 Combine	2013	10,272.40	0.00	29,517.17	(29,517.17)	-287.34%	-160.08%	-48.04%	-46.67%	-23.96%	-22.47%	-23.14%	-23.14%	-23.14%	-23.12%
379 Combine	2014	18,927.28	0.00	3,178.72	(3,178.72)	-16.79%	-111.97%	-90.38%	-43.19%	-42.65%	-23.48%	-22.12%	-22.75%	-22.75%	-22.75%
369378379	1996	-	-	230.00	(230.00)	NA									
369378379	1997	-	-	-	0.00	NA	NA								
369378379	1998	13,898.00	-	100.00	(100.00)	-0.72%	-0.72%	-2.37%							
369378379	1999	2,464.00	-	-	0.00	0.00%	-0.61%	-0.61%	-2.02%						
369378379	2000	12,823.00	-	2,112.00	(2,112.00)	-16.47%	-13.82%	-7.58%	-7.58%	-8.37%					
369378379	2001	2,183.00	-	-	0.00	0.00%	-14.07%	-12.09%	-7.05%	-7.05%	-7.79%				
369378379	2002	-	-	-	0.00	NA	0.00%	-14.07%	-12.09%	-7.05%	-7.05%	-7.79%			
369378379	2003	-	-	-	0.00	NA	NA	0.00%	-14.07%	-12.09%	-7.05%	-7.05%	-7.79%		
369378379	2004	302.00	-	-	0.00	0.00%	0.00%	0.00%	0.00%	-13.80%	-11.88%	-6.98%	-6.98%	-7.71%	
369378379	2005	-	-	-	0.00	NA	0.00%	0.00%	0.00%	0.00%	-13.80%	-11.88%	-6.98%	-6.98%	-7.71%
369378379	2006	12,626.52	-	7,595.24	(7,595.24)	-60.15%	-60.15%	-58.75%	-58.75%	-58.75%	-50.26%	-34.75%	-31.93%	-22.14%	-22.14%
369378379	2007	24,754.08	-	57,129.82	(57,129.82)	-230.79%	-173.15%	-173.15%	-171.76%	-171.76%	-171.76%	-162.36%	-126.85%	-121.19%	-96.94%
369378379	2008	102,611.29	-	27,327.02	(27,327.02)	-26.63%	-66.31%	-65.76%	-65.76%	-65.61%	-65.61%	-65.61%	-64.61%	-60.63%	-59.69%
369378379	2009	353,848.54	-	21,867.53	(21,867.53)	-6.18%	-10.78%	-22.10%	-23.07%	-23.07%	-23.05%	-23.05%	-23.05%	-22.95%	-22.79%
369378379	2010	58,560.82	(5,555.50)	(44,745.20)	39,189.70	66.92%	4.20%	-1.94%	-12.44%	-13.53%	-13.53%	-13.52%	-13.52%	-13.52%	-13.47%
369378379	2011	152,240.43	-	34,199.56	(34,199.56)	-22.46%	2.37%	-2.99%	-6.62%	-14.64%	-15.46%	-15.46%	-15.45%	-15.45%	-15.45%
369378379	2012	28,669.87	-	5,202.00	(5,202.00)	-18.14%	-21.78%	-0.09%	-3.72%	-7.10%	-14.78%	-15.56%	-15.56%	-15.56%	-15.56%
369378379	2013	19,553.28	-	43,715.62	(43,715.62)	-223.57%	-101.44%	-41.46%	-16.96%	-10.74%	-13.02%	-20.30%	-20.97%	-20.97%	-20.96%
369378379	2014	79,355.57	-	8,019.33	(8,019.33)	-10.11%	-52.31%	-44.63%	-32.57%	-15.35%	-10.66%	-12.72%	-19.31%	-19.93%	-19.93%
38000	1996	176,565.00	0.00	27,636.00	(27,636.00)	-15.65%									
38000	1997	215,379.00	154.00	29,621.00	(29,467.00)	-13.68%	-14.57%								
38000	1998	0.00	0.00	16,139.00	(16,139.00)	NA	-21.17%	-18.69%							
38000	1999	340,026.00	0.00	253,715.00	(253,715.00)	-74.62%	-79.36%	-53.89%	-44.67%						
38000	2000	436,424.00	0.00	559,854.00	(559,854.00)	-128.28%	-104.78%	-106.86%	-86.63%	-75.90%					
38000	2001	1,081,065.00	0.00	450,538.00	(450,538.00)	-41.68%	-66.58%	-68.05%	-68.92%	-63.18%	-59.45%				
38000	2002	353,920.00	0.00	282,498.00	(282,498.00)	-79.82%	-51.08%	-69.09%	-69.94%	-70.67%	-65.61%	-62.22%			
38000	2003	573,781.00	0.00	600,977.00	(600,977.00)	-104.74%	-95.23%	-66.41%	-77.45%	-77.11%	-77.69%	-73.09%	-69.90%		
38000	2004	127,032.00	0.00	479,035.00	(479,035.00)	-377.10%	-154.11%	-129.18%	-84.89%	-92.25%	-90.19%	-90.75%	-85.44%	-81.71%	
38000	2005	540,726.00	0.00	257,365.70	(257,365.70)	-47.60%	-110.28%	-107.72%	-101.53%	-77.35%	-84.49%	-83.52%	-83.99%	-79.86%	-76.91%
38000	2006	1,319,885.85	0.00	760,811.91	(760,811.91)	-57.64%	-54.72%	-75.33%	-81.91%	-81.66%	-70.84%	-76.50%	-76.37%	-76.70%	-73.98%
38000	2007	163,701.52	0.00	351,967.59	(351,967.59)	-215.01%	-75.01%	-67.68%	-85.95%	-89.91%	-88.75%	-76.52%	-81.43%	-80.96%	-81.29%
38000	2008	70,172.83	0.00	23,861.28	(23,861.28)	-34.00%	-160.70%	-73.15%	-66.56%	-84.31%	-88.51%	-87.53%	-75.81%	-80.72%	-80.30%
38000	2009	2,051,975.52	0.00	6.68	(6.68)	0.00%	-1.12%	-16.44%	-31.52%	-33.62%	-43.83%	-51.04%	-53.00%	-51.05%	-56.07%
38000	2010	1,905,040.23	0.00	2,062,318.57	(2,062,318.57)	-108.26%	-52.12%	-51.80%	-58.18%	-58.05%	-57.12%	-63.69%	-67.18%	-67.81%	-64.36%
38000	2011	3,127,618.96	0.00	957,930.89	(957,930.89)	-30.63%	-60.01%	-42.63%	-42.55%	-46.40%	-48.12%	-48.09%	-52.58%	-55.61%	-56.45%
38000	2012	2,788,516.67	0.00	1,345,462.43	(1,345,462.43)	-48.25%	-38.93%	-55.82%	-44.22%	-44.15%	-46.91%	-48.15%	-48.13%	-51.58%	-53.99%
38000	2013	1,104,233.03	0.00	1,326,141.76	(1,326,141.76)	-120.10%	-68.63%	-51.70%	-63.77%	-51.85%	-51.74%	-54.12%	-54.49%	-54.21%	-57.31%
38000	2014	1,010,606.37	0.00	900,316.42	(900,316.42)	-89.09%	-105.28%	-72.85%	-56.40%	-66.35%	-54.99%	-54.87%	-57.01%	-57.07%	-56.71%
38100	1996	796,549.00	359,733.00	3,981.00	355,752.00	44.66%									
38100	1997	165,892.00	20,205.00	109.00	20,096.00	12.11%	39.05%								
38100	1998	5,818.00	38,534.00	0.00	38,534.00	662.32%	34.14%	42.80%							
38100	1999	292,116.00	0.00	26,537.00	(26,537.00)	-9.08%	4.03%	6.92%	30.77%						
38100	2000	0.00	0.00	0.00	0.00	NA	-9.08%	4.03%	6.92%	30.77%					
38100	2001	0.00	0.00	0.00	0.00	NA	NA	-9.08%	4.03%	6.92%	30.77%				
38100	2002	0.00	0.00	0.00	0.00	NA	NA	NA	-9.08%	4.03%	6.92%	30.77%			
38100	2003	9,244,466.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-0.28%	0.13%	0.33%	3.69%		
38100	2004	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	-0.28%	0.13%	0.33%	3.69%	
38100	2005	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	-0.28%	0.13%	0.33%	3.69%

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
38100	2006	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	-0.28%	0.13%	0.33%
38100	2007	588,405.23	0.00	52,883.71	(52,883.71)	-8.99%	-8.99%	-8.99%	-8.99%	-0.54%	-0.54%	-0.54%	-0.54%	-0.78%	-0.40%
38100	2008	257,366.09	0.00	5,632.13	(5,632.13)	-2.19%	-6.92%	-6.92%	-6.92%	-6.92%	-0.58%	-0.58%	-0.58%	-0.58%	-0.82%
38100	2009	25,930.63	0.00	61,850.47	(61,850.47)	-238.52%	-23.82%	-13.81%	-13.81%	-13.81%	-13.81%	-1.19%	-1.19%	-1.19%	-1.19%
38100	2010	0.00	0.00	0.00	0.00	NA	-238.52%	-23.82%	-13.81%	-13.81%	-13.81%	-13.81%	-1.19%	-1.19%	-1.19%
38100	2011	28,202.94	0.00	0.00	0.00	0.00%	0.00%	-114.26%	-21.66%	-13.38%	-13.38%	-13.38%	-13.38%	-1.19%	-1.19%
38100	2012	303,636.12	0.00	186,922.64	(186,922.64)	-61.56%	-56.33%	-56.33%	-69.53%	-41.36%	-25.53%	-25.53%	-25.53%	-25.53%	-2.94%
38100	2013	24,129.65	0.00	31,850.45	(31,850.45)	-132.00%	-66.75%	-61.46%	-61.46%	-73.48%	-44.78%	-27.62%	-27.62%	-27.62%	-27.62%
38100	2014	723,288.65	0.00	31,182.85	(31,182.85)	-4.31%	-8.43%	-23.78%	-23.16%	-23.16%	-28.21%	-23.30%	-18.98%	-18.98%	-18.98%
38200	1996	50,071.00	0.00	61,106.00	(61,106.00)	-122.04%									
38200	1997	61,875.00	0.00	106,958.00	(106,958.00)	-172.86%	-150.13%								
38200	1998	0.00	0.00	9,625.00	(9,625.00)	NA	-188.42%	-158.73%							
38200	1999	10,925.00	0.00	7,540.00	(7,540.00)	-69.02%	-157.12%	-170.50%	-150.75%						
38200	2000	79,200.00	0.00	414,823.00	(414,823.00)	-523.77%	-468.64%	-479.32%	-354.57%	-296.95%					
38200	2001	57,297.00	0.00	161,169.00	(161,169.00)	-281.29%	-421.98%	-395.82%	-402.35%	-334.51%	-293.49%				
38200	2002	250,858.00	0.00	1,139,462.00	(1,139,462.00)	-454.23%	-422.07%	-442.86%	-432.61%	-435.03%	-399.77%	-372.52%			
38200	2003	312,393.00	0.00	536,125.00	(536,125.00)	-171.62%	-297.48%	-295.99%	-321.77%	-317.88%	-319.24%	-307.52%	-296.23%		
38200	2004	203,956.00	0.00	521,798.00	(521,798.00)	-255.84%	-204.89%	-286.41%	-286.06%	-306.89%	-304.05%	-305.10%	-296.72%	-288.20%	
38200	2005	110,560.00	0.00	157,057.38	(157,057.38)	-142.06%	-215.84%	-193.80%	-268.23%	-269.03%	-288.92%	-286.58%	-287.52%	-280.99%	-273.99%
38200	2006	527,452.65	0.00	943,844.31	(943,844.31)	-178.94%	-172.55%	-192.73%	-187.01%	-234.72%	-236.54%	-251.30%	-250.01%	-250.63%	-247.65%
38200	2007	57,689.42	0.00	118,098.97	(118,098.97)	-204.72%	-181.48%	-175.22%	-193.50%	-187.86%	-233.53%	-235.33%	-249.62%	-248.39%	-248.99%
38200	2008	0.00	0.00	10,247.87	(10,247.87)	NA	-222.48%	-183.24%	-176.69%	-194.63%	-188.70%	-234.23%	-236.01%	-250.26%	-249.03%
38200	2009	1,027,944.08	0.00	6.68	(6.68)	0.00%	-1.00%	-11.82%	-66.47%	-71.32%	-90.84%	-102.11%	-137.57%	-140.80%	-152.34%
38200	2010	475,356.72	0.00	4,428,392.75	(4,428,392.75)	-931.59%	-294.58%	-295.26%	-291.91%	-263.38%	-257.28%	-257.16%	-247.32%	-264.82%	-265.13%
38200	2011	1,816,947.23	0.00	964,264.66	(964,264.66)	-53.07%	-235.25%	-162.42%	-162.73%	-163.44%	-165.54%	-164.89%	-169.29%	-169.45%	-184.38%
38200	2012	583,219.78	0.00	314,535.00	(314,535.00)	-53.93%	-53.28%	-198.47%	-146.21%	-146.47%	-147.32%	-151.04%	-150.82%	-155.28%	-156.28%
38200	2013	164,052.93	0.00	0.00	0.00	0.00%	-42.09%	-49.87%	-187.76%	-140.31%	-140.56%	-141.46%	-145.71%	-145.63%	-150.15%
38200	2014	0.00	0.00	8,717.20	(8,717.20)	NA	-5.31%	-43.26%	-50.21%	-188.05%	-140.53%	-140.78%	-141.67%	-145.90%	-145.81%
381-382 C	1996	846,620.00	359,733.00	65,087.00	294,646.00	34.80%									
381-382 C	1997	227,767.00	20,205.00	107,067.00	(86,862.00)	-38.14%	19.34%								
381-382 C	1998	5,818.00	38,534.00	9,625.00	28,909.00	496.89%	-24.81%	21.91%							
381-382 C	1999	303,041.00	0.00	34,077.00	(34,077.00)	-11.25%	-1.67%	-17.15%	14.65%						
381-382 C	2000	79,200.00	0.00	414,823.00	(414,823.00)	-523.77%	-117.44%	-108.23%	-82.30%	-14.51%					
381-382 C	2001	57,297.00	0.00	161,169.00	(161,169.00)	-281.29%	-421.98%	-138.80%	-130.49%	-99.24%	-24.57%				
381-382 C	2002	250,858.00	0.00	1,139,462.00	(1,139,462.00)	-454.23%	-422.07%	-442.86%	-253.41%	-247.14%	-195.62%	-85.44%			
381-382 C	2003	9,556,859.00	0.00	536,125.00	(536,125.00)	-5.61%	-17.08%	-18.62%	-22.64%	-22.31%	-22.01%	-22.36%	-18.09%		
381-382 C	2004	203,956.00	0.00	521,798.00	(521,798.00)	-255.84%	-10.84%	-21.95%	-23.42%	-27.33%	-26.86%	-26.57%	-26.82%	-22.29%	
381-382 C	2005	110,560.00	0.00	157,057.38	(157,057.38)	-142.06%	-215.84%	-12.31%	-23.26%	-24.71%	-28.57%	-28.07%	-27.78%	-28.00%	-23.43%
381-382 C	2006	527,452.65	0.00	943,844.31	(943,844.31)	-178.94%	-172.55%	-192.73%	-20.76%	-30.97%	-32.31%	-35.92%	-35.24%	-34.97%	-35.03%
381-382 C	2007	646,094.65	0.00	170,982.68	(170,982.68)	-26.46%	-95.00%	-99.05%	-120.54%	-21.09%	-30.71%	-31.98%	-35.38%	-34.76%	-34.50%
381-382 C	2008	257,366.09	0.00	15,880.00	(15,880.00)	-6.17%	-20.68%	-79.02%	-83.54%	-103.67%	-20.75%	-30.17%	-31.41%	-34.74%	-34.15%
381-382 C	2009	1,053,874.71	0.00	61,857.15	(61,857.15)	-5.87%	-5.93%	-12.71%	-47.99%	-52.00%	-66.85%	-19.48%	-28.14%	-29.28%	-32.35%
381-382 C	2010	475,356.72	0.00	4,428,392.75	(4,428,392.75)	-931.59%	-293.63%	-252.22%	-192.26%	-189.89%	-188.17%	-192.38%	-53.27%	-60.96%	-61.92%
381-382 C	2011	1,845,150.17	0.00	964,264.66	(964,264.66)	-52.26%	-232.39%	-161.64%	-150.63%	-131.87%	-137.04%	-137.15%	-141.88%	-53.15%	-59.89%
381-382 C	2012	886,855.90	0.00	501,457.64	(501,457.64)	-56.54%	-53.65%	-183.77%	-139.77%	-132.16%	-118.94%	-124.50%	-124.83%	-129.28%	-53.34%
381-382 C	2013	188,182.58	0.00	31,850.45	(31,850.45)	-16.93%	-49.61%	-51.28%	-174.52%	-134.58%	-127.55%	-115.35%	-121.06%	-121.44%	-125.87%
381-382 C	2014	723,288.65	0.00	39,900.05	(39,900.05)	-5.52%	-7.87%	-31.87%	-42.20%	-144.84%	-116.53%	-111.30%	-102.28%	-108.40%	-108.96%
38300	1996	143,491.00	0.00	0.00	0.00	0.00%									
38300	1997	0.00	0.00	0.00	0.00	NA	0.00%								
38300	1998	264,277.00	0.00	0.00	0.00	0.00%	0.00%	0.00%							
38300	1999	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%						
38300	2000	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%					
38300	2001	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%				

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
38300	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%			
38300	2003	68.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
38300	2004	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38300	2005	4,054.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
38300	2006	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
38300	2007	1,772.42	0.00	1,452.91	(1,452.91)	-81.97%	-81.97%	-24.94%	-24.94%	-24.65%	-24.65%	-24.65%	-24.65%	-24.65%	-0.54%
38300	2008	12,152.66	0.00	4,449.80	(4,449.80)	-36.62%	-42.39%	-42.39%	-32.83%	-32.83%	-32.71%	-32.71%	-32.71%	-32.71%	-32.71%
38300	2009	0.00	0.00	3,140.90	(3,140.90)	NA	-62.46%	-64.94%	-64.94%	-50.30%	-50.30%	-50.11%	-50.11%	-50.11%	-50.11%
38300	2010	0.00	0.00	793.20	(793.20)	NA	NA	-68.99%	-70.64%	-70.64%	-54.71%	-54.71%	-54.51%	-54.51%	-54.51%
38300	2011	420,633.12	0.00	34,098.62	(34,098.62)	-8.11%	-8.30%	-9.04%	-9.82%	-10.11%	-10.11%	-10.02%	-10.02%	-10.02%	-10.02%
38300	2012	7,277.76	0.00	153,966.41	(153,966.41)	-2115.57%	-43.95%	-44.13%	-44.87%	-44.64%	-44.79%	-44.79%	-44.38%	-44.38%	-44.38%
38300	2013	0.00	0.00	0.00	0.00	NA	-2115.57%	-43.95%	-44.13%	-44.87%	-44.64%	-44.79%	-44.79%	-44.38%	-44.38%
38300	2014	50.61	0.00	79,296.38	(79,296.38)	-156681.25%	-156681.25%	-3183.01%	-62.47%	-62.66%	-63.39%	-62.65%	-62.73%	-62.73%	-62.16%
38400	1996	0.00	0.00	0.00	0.00	NA									
38400	1997	2,664.00	0.00	0.00	0.00	0.00%	0.00%								
38400	1998	0.00	0.00	0.00	0.00	NA	0.00%	0.00%							
38400	1999	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%						
38400	2000	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%					
38400	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%				
38400	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%			
38400	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	0.00%	0.00%		
38400	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	
38400	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
38400	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
38400	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38400	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38400	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38400	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38400	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38400	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38400	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38400	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
381-384	1996	990,111.00	359,733.00	65,087.00	294,646.00	29.76%									
381-384	1997	230,431.00	20,205.00	107,067.00	(86,862.00)	-37.70%	17.02%								
381-384	1998	270,095.00	38,534.00	9,625.00	28,909.00	10.70%	-11.58%	15.88%							
381-384	1999	303,041.00	0.00	34,077.00	(34,077.00)	-11.25%	-0.90%	-11.45%	11.30%						
381-384	2000	79,200.00	0.00	414,823.00	(414,823.00)	-523.77%	-117.44%	-64.38%	-57.42%	-11.33%					
381-384	2001	57,297.00	0.00	161,169.00	(161,169.00)	-281.29%	-421.98%	-138.80%	-81.90%	-71.06%	-19.34%				
381-384	2002	250,858.00	0.00	1,139,462.00	(1,139,462.00)	-454.23%	-422.07%	-442.86%	-253.41%	-179.14%	-151.77%	-69.36%			
381-384	2003	9,556,927.00	0.00	536,125.00	(536,125.00)	-5.61%	-17.08%	-18.62%	-22.64%	-22.30%	-21.46%	-21.81%	-17.46%		
381-384	2004	203,956.00	0.00	521,798.00	(521,798.00)	-255.84%	-10.84%	-21.95%	-23.42%	-27.33%	-26.86%	-25.92%	-26.16%	-21.53%	
381-384	2005	114,614.00	0.00	157,057.38	(157,057.38)	-137.03%	-213.09%	-12.30%	-23.25%	-24.70%	-28.55%	-28.06%	-27.09%	-27.31%	-22.63%
381-384	2006	527,452.65	0.00	943,844.31	(943,844.31)	-178.94%	-171.46%	-191.80%	-20.75%	-30.96%	-32.30%	-35.91%	-35.23%	-34.14%	-34.21%
381-384	2007	647,867.07	0.00	172,435.59	(172,435.59)	-26.62%	-94.98%	-98.71%	-120.17%	-21.10%	-30.71%	-31.97%	-35.38%	-34.76%	-33.73%
381-384	2008	269,518.75	0.00	20,329.80	(20,329.80)	-7.54%	-21.01%	-78.67%	-82.96%	-102.95%	-20.77%	-30.17%	-31.41%	-34.74%	-34.15%
381-384	2009	1,053,874.71	0.00	64,998.05	(64,998.05)	-6.17%	-6.45%	-13.08%	-48.09%	-51.99%	-66.75%	-19.53%	-28.17%	-29.31%	-32.38%
381-384	2010	475,356.72	0.00	4,429,185.95	(4,429,185.95)	-931.76%	-293.89%	-250.98%	-191.57%	-189.33%	-187.39%	-191.63%	-53.28%	-60.95%	-61.91%
381-384	2011	2,265,783.29	0.00	998,363.28	(998,363.28)	-44.06%	-198.00%	-144.73%	-135.63%	-120.65%	-126.51%	-126.74%	-131.48%	-51.90%	-58.46%
381-384	2012	894,133.66	0.00	655,424.05	(655,424.05)	-73.30%	-52.34%	-167.33%	-131.11%	-124.39%	-113.10%	-118.76%	-119.09%	-123.42%	-53.09%
381-384	2013	188,182.58	0.00	31,850.45	(31,850.45)	-16.93%	-63.50%	-50.35%	-159.93%	-126.70%	-120.46%	-109.97%	-115.73%	-116.11%	-120.40%
381-384	2014	723,339.26	0.00	119,196.43	(119,196.43)	-16.48%	-16.57%	-44.66%	-44.33%	-137.11%	-112.47%	-107.65%	-99.60%	-105.54%	-106.04%
38500	1996	16,570.00	1,028.00	3.00	1,025.00	6.19%									
38500	1997	2,204.00	0.00	18.00	(18.00)	-0.82%	5.36%								

CASE NO. 2017-00349
FR 16(7)(s)
ATTACHMENT 1

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
38500	1998	14,263.00	0.00	10.00	(10.00)	-0.07%	-0.17%	3.02%							
38500	1999	6,054.00	0.00	0.00	0.00	0.00%	-0.05%	-0.12%	2.55%						
38500	2000	681.00	0.00	1,698.00	(1,698.00)	-249.34%	-25.21%	-8.13%	-7.44%	-1.76%					
38500	2001	16,167.00	0.00	7,896.00	(7,896.00)	-48.84%	-56.94%	-41.89%	-25.84%	-24.44%	-15.37%				
38500	2002	0.00	0.00	0.00	0.00	NA	-48.84%	-56.94%	-41.89%	-25.84%	-24.44%	-15.37%			
38500	2003	0.00	0.00	0.00	0.00	NA	NA	-48.84%	-56.94%	-41.89%	-25.84%	-24.44%	-15.37%		
38500	2004	0.00	0.00	0.00	0.00	NA	NA	NA	-48.84%	-56.94%	-41.89%	-25.84%	-24.44%	-15.37%	
38500	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-48.84%	-56.94%	-41.89%	-25.84%	-24.44%	-15.37%
38500	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-48.84%	-56.94%	-41.89%	-25.84%	-24.44%
38500	2007	11,825.65	0.00	3,573.10	(3,573.10)	-30.21%	-30.21%	-30.21%	-30.21%	-30.21%	-30.21%	-40.97%	-45.92%	-37.92%	-26.90%
38500	2008	30,185.21	0.00	0.00	0.00	0.00%	-8.51%	-8.51%	-8.51%	-8.51%	-8.51%	-8.51%	-19.71%	-22.37%	-20.28%
38500	2009	3,375.49	0.00	9,908.55	(9,908.55)	-293.54%	-29.52%	-29.70%	-29.70%	-29.70%	-29.70%	-29.70%	-29.70%	-34.73%	-37.08%
38500	2010	10,244.48	0.00	1,623.46	(1,623.46)	-15.85%	-84.67%	-26.33%	-27.15%	-27.15%	-27.15%	-27.15%	-27.15%	-27.15%	-32.04%
38500	2011	8,965.63	0.00	3,423.04	(3,423.04)	-38.18%	-26.27%	-66.21%	-28.34%	-28.68%	-28.68%	-28.68%	-28.68%	-28.68%	-28.68%
38500	2012	6,250.67	0.00	6,610.76	(6,610.76)	-105.76%	-65.94%	-45.79%	-74.79%	-36.54%	-35.48%	-35.48%	-35.48%	-35.48%	-35.48%
38500	2013	14,688.61	0.00	4,225.95	(4,225.95)	-28.77%	-51.75%	-47.68%	-39.56%	-59.26%	-34.99%	-34.33%	-34.33%	-34.33%	-34.33%
38500	2014	7,819.11	0.00	(20,568.02)	20,568.02	263.05%	72.61%	33.84%	16.72%	9.77%	-10.17%	-6.41%	-9.42%	-9.42%	-9.42%
39000	1996	0.00	0.00	0.00	0.00	NA									
39000	1997	0.00	0.00	0.00	0.00	NA	NA								
39000	1998	1,718.00	0.00	0.00	0.00	0.00%	0.00%	0.00%							
39000	1999	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%						
39000	2000	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%					
39000	2001	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%				
39000	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%			
39000	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%		
39000	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	
39000	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39000	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
39000	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
39000	2008	0.00	0.00	273.72	(273.72)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39000	2009	0.00	0.00	441.53	(441.53)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39000	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39000	2011	200.77	0.00	0.00	0.00	0.00%	0.00%	-219.92%	-356.25%	-356.25%	-356.25%	-356.25%	-356.25%	-356.25%	-356.25%
39000	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	-219.92%	-356.25%	-356.25%	-356.25%	-356.25%	-356.25%	-356.25%
39000	2013	5,256.31	0.00	829.53	(829.53)	-15.78%	-15.78%	-15.20%	-15.20%	-23.29%	-28.31%	-28.31%	-28.31%	-28.31%	-28.31%
39000	2014	0.00	0.00	0.00	0.00	NA	-15.78%	-15.78%	-15.20%	-15.20%	-23.29%	-28.31%	-28.31%	-28.31%	-28.31%
39002	1996	0.00	0.00	0.00	0.00	NA									
39002	1997	0.00	0.00	0.00	0.00	NA	NA								
39002	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39002	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39002	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39002	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39002	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39002	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39002	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39002	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39002	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39002	2007	6,777.28	0.00	32.40	(32.40)	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%
39002	2008	5,677.04	1,993.50	7,673.52	(5,680.02)	-100.05%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%
39002	2009	0.00	0.00	0.00	0.00	NA	-100.05%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%	-45.87%
39002	2010	2,388.33	0.00	1,209.73	(1,209.73)	-50.65%	-50.65%	-85.42%	-46.64%	-46.64%	-46.64%	-46.64%	-46.64%	-46.64%	-46.64%
39002	2011	0.00	0.00	0.00	0.00	NA	-50.65%	-50.65%	-85.42%	-46.64%	-46.64%	-46.64%	-46.64%	-46.64%	-46.64%
39002	2012	0.00	0.00	0.00	0.00	NA	NA	-50.65%	-50.65%	-85.42%	-46.64%	-46.64%	-46.64%	-46.64%	-46.64%
39002	2013	0.00	0.00	0.00	0.00	NA	NA	NA	-50.65%	-50.65%	-85.42%	-46.64%	-46.64%	-46.64%	-46.64%
39002	2014	5,640.51	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	-15.07%	-15.07%	-50.27%	-33.79%	-33.79%	-33.79%

Appendix D

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NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
39003	1996	0.00	0.00	0.00	0.00	NA									
39003	1997	0.00	0.00	0.00	0.00	NA	NA								
39003	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39003	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39003	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39003	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39003	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39003	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39003	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39003	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39003	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39003	2007	23,304.50	0.00	111.32	(111.32)	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%
39003	2008	3,448.82	1,694.20	0.81	1,693.39	49.10%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
39003	2009	0.00	0.00	0.00	0.00	NA	49.10%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
39003	2010	2,511.27	0.00	110.28	(110.28)	-4.39%	-4.39%	26.56%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%
39003	2011	0.00	0.00	0.00	0.00	NA	-4.39%	-4.39%	26.56%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%
39003	2012	0.00	0.00	0.00	0.00	NA	NA	-4.39%	-4.39%	26.56%	5.03%	5.03%	5.03%	5.03%	5.03%
39003	2013	0.00	0.00	0.00	0.00	NA	NA	NA	-4.39%	-4.39%	26.56%	5.03%	5.03%	5.03%	5.03%
39003	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-4.39%	-4.39%	26.56%	5.03%	5.03%	5.03%
39004	1996	0.00	0.00	0.00	0.00	NA									
39004	1997	0.00	0.00	0.00	0.00	NA	NA								
39004	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39004	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39004	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39004	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39004	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39004	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39004	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39004	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39004	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39004	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39004	2008	2,310.00	1,134.76	0.52	1,134.24	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%
39004	2009	0.00	0.00	0.00	0.00	NA	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%
39004	2010	0.00	0.00	0.00	0.00	NA	NA	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%
39004	2011	0.00	0.00	0.00	0.00	NA	NA	NA	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%
39004	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	49.10%	49.10%	49.10%	49.10%	49.10%	49.10%
39004	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	49.10%	49.10%	49.10%	49.10%	49.10%
39004	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	49.10%	49.10%	49.10%	49.10%
390 Combine	1996	0.00	0.00	0.00	0.00	NA									
390 Combine	1997	0.00	0.00	0.00	0.00	NA	NA								
390 Combine	1998	1,718.00	0.00	0.00	0.00	0.00%	0.00%	0.00%							
390 Combine	1999	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%						
390 Combine	2000	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%					
390 Combine	2001	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%				
390 Combine	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%			
390 Combine	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%		
390 Combine	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	
390 Combine	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
390 Combine	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
390 Combine	2007	30,081.78	0.00	143.72	(143.72)	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.45%
390 Combine	2008	11,435.86	4,822.46	7,948.57	(3,126.11)	-27.34%	-7.88%	-7.88%	-7.88%	-7.88%	-7.88%	-7.88%	-7.88%	-7.88%	-7.88%
390 Combine	2009	0.00	0.00	441.53	(441.53)	NA	-31.20%	-8.94%	-8.94%	-8.94%	-8.94%	-8.94%	-8.94%	-8.94%	-8.94%
390 Combine	2010	4,899.60	0.00	1,320.01	(1,320.01)	-26.94%	-35.95%	-29.92%	-10.84%	-10.84%	-10.84%	-10.84%	-10.84%	-10.84%	-10.84%

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
390 Combine	2011	200.77	0.00	0.00	0.00	0.00%	-25.88%	-34.54%	-29.56%	-10.79%	-10.79%	-10.79%	-10.79%	-10.79%	-10.79%
390 Combine	2012	0.00	0.00	0.00	0.00	NA	0.00%	-25.88%	-34.54%	-29.56%	-10.79%	-10.79%	-10.79%	-10.79%	-10.79%
390 Combine	2013	5,256.31	0.00	829.53	(829.53)	-15.78%	-15.78%	-15.20%	-20.76%	-25.02%	-26.23%	-11.30%	-11.30%	-11.30%	-11.30%
390 Combine	2014	5,640.51	0.00	0.00	0.00	0.00%	-7.61%	-7.61%	-7.47%	-13.44%	-16.20%	-20.84%	-10.19%	-10.19%	-10.19%
39009	1996	0.00	0.00	0.00	0.00	NA									
39009	1997	0.00	0.00	0.00	0.00	NA	NA								
39009	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39009	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39009	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39009	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39009	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39009	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39009	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39009	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39009	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39009	2007	7,867.30	0.00	37.60	(37.60)	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%	-0.48%
39009	2008	59,961.62	13,843.97	136.83	13,707.14	22.86%	20.15%	20.15%	20.15%	20.15%	20.15%	20.15%	20.15%	20.15%	20.15%
39009	2009	455.00	0.00	221.75	(221.75)	-48.74%	22.32%	19.69%	19.69%	19.69%	19.69%	19.69%	19.69%	19.69%	19.69%
39009	2010	33,228.62	0.00	10,386.89	(10,386.89)	-31.26%	-31.49%	3.31%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%
39009	2011	0.00	0.00	0.00	0.00	NA	-31.26%	-31.49%	3.31%	3.02%	3.02%	3.02%	3.02%	3.02%	3.02%
39009	2012	0.00	0.00	0.00	0.00	NA	NA	-31.26%	-31.49%	3.31%	3.02%	3.02%	3.02%	3.02%	3.02%
39009	2013	0.00	0.00	0.00	0.00	NA	NA	NA	-31.26%	-31.49%	3.31%	3.02%	3.02%	3.02%	3.02%
39009	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-31.26%	-31.49%	3.31%	3.02%	3.02%	3.02%
39100	1996	14,396.00	0.00	0.00	0.00	0.00%									
39100	1997	0.00	2,809.00	0.00	2,809.00	NA	19.51%								
39100	1998	6,356.00	1,342.00	0.00	1,342.00	21.11%	65.31%	20.00%							
39100	1999	1,465.00	0.00	0.00	0.00	0.00%	17.16%	53.08%	18.68%						
39100	2000	13,341.00	0.00	0.00	0.00	0.00%	0.00%	6.34%	19.62%	11.67%					
39100	2001	72,169.00	0.00	28.00	(28.00)	-0.04%	-0.03%	-0.03%	1.41%	4.42%	3.83%				
39100	2002	94,992.00	0.00	0.00	0.00	0.00%	-0.02%	-0.02%	-0.02%	0.70%	2.19%	2.03%			
39100	2003	15,380.00	0.00	0.00	0.00	0.00%	0.00%	-0.02%	-0.01%	-0.01%	0.65%	2.02%	1.89%		
39100	2004	38,289.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	-0.01%	-0.01%	-0.01%	0.54%	1.70%	1.61%	
39100	2005	548,104.13	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	0.52%	0.51%
39100	2006	66,372.83	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.15%	0.48%
39100	2007	18,622.22	671.60	7.01	664.59	3.57%	0.78%	0.10%	0.10%	0.10%	0.09%	0.07%	0.07%	0.07%	0.23%
39100	2008	905,386.11	0.00	4,119.31	(4,119.31)	-0.45%	-0.37%	-0.35%	-0.22%	-0.22%	-0.22%	-0.20%	-0.20%	-0.20%	-0.20%
39100	2009	7,148.71	0.00	3,381.68	(3,381.68)	-47.30%	-0.82%	-0.73%	-0.69%	-0.44%	-0.43%	-0.43%	-0.40%	-0.39%	-0.39%
39100	2010	240.18	0.00	0.00	0.00	0.00%	-45.77%	-0.82%	-0.73%	-0.69%	-0.44%	-0.43%	-0.43%	-0.40%	-0.39%
39100	2011	22,501.95	0.00	0.00	0.00	0.00%	0.00%	-11.31%	-0.80%	-0.72%	-0.67%	-0.44%	-0.43%	-0.42%	-0.40%
39100	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	-11.31%	-0.80%	-0.72%	-0.67%	-0.44%	-0.43%	-0.42%
39100	2013	3,835.95	0.00	134.23	(134.23)	-3.50%	-3.50%	-0.51%	-0.51%	-10.42%	-0.81%	-0.73%	-0.68%	-0.44%	-0.43%
39100	2014	55,783.60	0.00	0.00	0.00	0.00%	-0.23%	-0.23%	-0.16%	-0.16%	-3.93%	-0.77%	-0.69%	-0.65%	-0.43%
39103	1996	0.00	0.00	0.00	0.00	NA									
39103	1997	0.00	0.00	0.00	0.00	NA	NA								
39103	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39103	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39103	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39103	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39103	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39103	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39103	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39103	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39103	2006	806.28	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
39103	2007	481.51	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39103	2008	425.55	209.05	0.10	208.95	49.10%	23.04%	12.20%	12.20%	12.20%	12.20%	12.20%	12.20%	12.20%	12.20%
39103	2009	92,409.59	0.00	0.00	0.00	0.00%	0.23%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%
39103	2010	407.52	0.00	0.00	0.00	0.00%	0.00%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%
39103	2011	1,388.59	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%
39103	2012	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%
39103	2013	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.22%	0.22%	0.22%	0.22%	0.22%
39103	2014	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.22%	0.22%	0.22%	0.22%
39200	1996	623,819.00	189,432.51	1,191.00	188,241.51	30.18%									
39200	1997	131,611.00	40,503.00	615.00	39,888.00	30.31%	30.20%								
39200	1998	550,378.00	127,968.00	8.00	127,960.00	23.25%	24.61%	27.27%							
39200	1999	291,792.00	77,749.00	275.00	77,474.00	26.55%	24.39%	25.19%	27.14%						
39200	2000	810,884.00	101,794.00	0.00	101,794.00	12.55%	16.26%	18.59%	19.45%	22.23%					
39200	2001	549,771.00	7,561.00	0.00	7,561.00	1.38%	8.04%	11.31%	14.29%	15.19%	18.35%				
39200	2002	216,646.00	35,292.00	0.00	35,292.00	16.29%	5.59%	9.17%	11.88%	14.47%	15.29%	18.21%			
39200	2003	2,732,280.00	79,320.00	0.00	79,320.00	2.90%	3.89%	3.49%	5.20%	6.55%	8.34%	8.88%	11.13%		
39200	2004	559,510.00	0.00	0.00	0.00	0.00%	2.41%	3.27%	3.01%	4.60%	5.84%	7.52%	8.03%	10.17%	
39200	2005	394,260.00	67,019.33	4,646.18	62,373.15	15.82%	6.54%	3.84%	4.53%	4.14%	5.44%	6.55%	8.05%	8.52%	10.49%
39200	2006	82,381.07	0.00	0.00	0.00	0.00%	13.09%	6.02%	3.76%	4.44%	4.07%	5.36%	6.45%	7.95%	8.41%
39200	2007	0.00	0.00	0.00	0.00	NA	0.00%	13.09%	6.02%	3.76%	4.44%	4.07%	5.36%	6.45%	7.95%
39200	2008	151,445.91	3,885.02	0.00	3,885.02	2.57%	2.57%	1.66%	10.55%	5.58%	3.71%	4.37%	4.02%	5.28%	6.35%
39200	2009	117,142.14	0.00	0.00	0.00	0.00%	1.45%	1.45%	1.11%	8.89%	5.08%	3.61%	4.25%	3.92%	5.17%
39200	2010	63,503.63	13,432.00	(131.26)	13,563.26	21.36%	7.51%	5.25%	5.25%	4.21%	9.87%	5.83%	3.88%	4.50%	4.15%
39200	2011	2,672.17	0.00	0.00	0.00	0.00%	20.50%	7.40%	5.21%	5.21%	4.18%	9.84%	5.82%	3.88%	4.50%
39200	2012	0.00	0.00	0.00	0.00	NA	0.00%	20.50%	7.40%	5.21%	5.21%	4.18%	9.84%	5.82%	3.88%
39200	2013	37,101.32	0.00	170.62	(170.62)	-0.46%	-0.46%	-0.43%	12.97%	6.08%	4.65%	4.65%	3.80%	9.39%	5.66%
39200	2014	97,648.39	7,291.18	198.32	7,092.86	7.26%	5.14%	5.14%	5.04%	10.20%	6.44%	5.19%	5.19%	4.42%	9.17%
39201	1996	0.00	0.00	0.00	0.00	NA									
39201	1997	0.00	0.00	0.00	0.00	NA	NA								
39201	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39201	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39201	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39201	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39201	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39201	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39201	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39201	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39201	2006	21,372.22	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2007	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2008	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2009	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2010	21,940.52	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2011	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2012	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2013	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39201	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39202	1996	0.00	0.00	0.00	0.00	NA									
39202	1997	0.00	0.00	0.00	0.00	NA	NA								
39202	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39202	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39202	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39202	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39202	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
39202	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39202	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39202	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39202	2006	27,841.74	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39202	2007	9,991.49	3,500.00	0.00	3,500.00	35.03%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%
39202	2008	9,529.38	1,545.59	(10,474.57)	12,020.16	126.14%	79.51%	32.77%	32.77%	32.77%	32.77%	32.77%	32.77%	32.77%	32.77%
39202	2009	39,259.65	0.00	0.00	0.00	0.00%	24.64%	26.40%	17.92%	17.92%	17.92%	17.92%	17.92%	17.92%	17.92%
39202	2010	25,154.17	0.00	0.00	0.00	0.00%	0.00%	16.26%	18.49%	13.89%	13.89%	13.89%	13.89%	13.89%	13.89%
39202	2011	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	16.26%	18.49%	13.89%	13.89%	13.89%	13.89%	13.89%
39202	2012	1,504.94	0.00	104.96	(104.96)	-6.97%	-6.97%	-0.39%	-0.16%	15.79%	18.04%	13.61%	13.61%	13.61%	13.61%
39202	2013	0.00	0.00	0.00	0.00	NA	-6.97%	-6.97%	-0.39%	-0.16%	15.79%	18.04%	13.61%	13.61%	13.61%
39202	2014	0.00	0.00	0.00	0.00	NA	NA	-6.97%	-6.97%	-0.39%	-0.16%	15.79%	18.04%	13.61%	13.61%
39400	1996	35,537.00	4,400.00	0.00	4,400.00	12.38%									
39400	1997	12,767.00	0.00	0.00	0.00	0.00%	9.11%								
39400	1998	0.00	0.00	0.00	0.00	NA	0.00%	9.11%							
39400	1999	4,300.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	8.36%						
39400	2000	25,384.00	10,742.00	0.00	10,742.00	42.32%	36.19%	36.19%	25.30%	19.42%					
39400	2001	18,601.00	0.00	0.00	0.00	0.00%	24.42%	22.25%	22.25%	17.59%	15.68%				
39400	2002	764,651.00	0.00	0.00	0.00	0.00%	0.00%	1.33%	1.32%	1.32%	1.30%	1.76%			
39400	2003	61,408.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	1.23%	1.23%	1.23%	1.21%	1.64%		
39400	2004	517,271.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.77%	0.77%	0.77%	0.76%	1.05%	
39400	2005	43,563.00	200.00	5.69	194.31	0.45%	0.03%	0.03%	0.01%	0.01%	0.76%	0.76%	0.76%	0.76%	1.03%
39400	2006	578,945.54	0.00	0.00	0.00	0.00%	0.03%	0.02%	0.02%	0.01%	0.01%	0.54%	0.54%	0.54%	0.54%
39400	2007	96,024.71	155.09	(367.06)	522.15	0.54%	0.08%	0.10%	0.06%	0.06%	0.03%	0.03%	0.54%	0.54%	0.54%
39400	2008	42,541.38	169.69	(79.32)	249.01	0.59%	0.56%	0.11%	0.13%	0.08%	0.07%	0.05%	0.05%	0.54%	0.54%
39400	2009	169,280.66	7,500.00	3,805.20	3,694.80	2.18%	1.86%	1.45%	0.50%	0.50%	0.32%	0.31%	0.20%	0.20%	0.66%
39400	2010	91,719.05	0.00	2,128.74	(2,128.74)	-2.32%	0.60%	0.60%	0.58%	0.24%	0.25%	0.16%	0.16%	0.11%	0.11%
39400	2011	76,934.17	0.00	123.21	(123.21)	-0.16%	-1.34%	0.43%	0.44%	0.46%	0.21%	0.22%	0.15%	0.14%	0.10%
39400	2012	106,303.90	21,457.91	1,222.32	20,235.59	19.04%	10.98%	6.54%	4.88%	4.50%	3.85%	1.93%	1.88%	1.31%	1.27%
39400	2013	95,483.59	0.00	201.50	(201.50)	-0.21%	9.93%	7.14%	4.80%	3.98%	3.73%	3.28%	1.77%	1.73%	1.23%
39400	2014	590,143.20	132.00	721.69	(589.69)	-0.10%	-0.12%	2.46%	2.22%	1.79%	1.85%	1.80%	1.71%	1.17%	1.16%
39600	1996	1,106.00	7,500.00	0.00	7,500.00	678.12%									
39600	1997	0.00	1,900.00	356.00	1,544.00	NA	817.72%								
39600	1998	1,515.00	520.00	0.00	520.00	34.32%	136.24%	364.90%							
39600	1999	22,556.00	0.00	0.00	0.00	0.00%	2.16%	8.57%	37.99%						
39600	2000	153,880.00	54,000.00	0.00	54,000.00	35.09%	30.61%	30.64%	31.51%	35.50%					
39600	2001	1,617.00	0.00	0.00	0.00	0.00%	34.73%	30.33%	30.36%	31.22%	35.18%				
39600	2002	278,879.00	22,479.00	0.00	22,479.00	8.06%	8.01%	17.61%	16.74%	16.80%	17.13%	18.72%			
39600	2003	357,777.00	0.00	0.00	0.00	0.00%	3.53%	3.52%	9.65%	9.39%	9.43%	9.62%	10.53%		
39600	2004	204,050.00	0.00	0.00	0.00	0.00%	0.00%	2.67%	2.67%	7.68%	7.51%	7.55%	7.70%	8.42%	
39600	2005	42,281.00	12,485.86	0.00	12,485.86	29.53%	5.07%	2.07%	3.96%	3.95%	8.57%	8.38%	8.42%	8.57%	9.26%
39600	2006	0.00	0.00	0.00	0.00	NA	29.53%	5.07%	2.07%	3.96%	3.95%	8.57%	8.38%	8.42%	8.57%
39600	2007	0.00	0.00	0.00	0.00	NA	NA	29.53%	5.07%	2.07%	3.96%	3.95%	8.57%	8.38%	8.42%
39600	2008	0.00	0.00	0.00	0.00	NA	NA	NA	29.53%	5.07%	2.07%	3.96%	3.95%	8.57%	8.38%
39600	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	29.53%	5.07%	2.07%	3.96%	3.95%	8.57%
39600	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	29.53%	5.07%	2.07%	3.96%	3.95%
39600	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	29.53%	5.07%	2.07%	3.96%
39600	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	29.53%	5.07%	2.07%
39600	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	29.53%	5.07%
39600	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	29.53%
39603	1996	0.00	0.00	0.00	0.00	NA									
39603	1997	0.00	0.00	0.00	0.00	NA	NA								
39603	1998	0.00	0.00	0.00	0.00	NA	NA	NA							

Appendix D

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NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
39603	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39603	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39603	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39603	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39603	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39603	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39603	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39603	2006	62,479.06	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2007	51,615.98	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2008	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2009	327.09	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2010	89,252.12	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2011	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2012	50,877.76	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2013	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39603	2014	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39604	1996	0.00	0.00	0.00	0.00	NA									
39604	1997	0.00	0.00	0.00	0.00	NA	NA								
39604	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39604	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39604	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39604	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39604	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39604	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39604	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39604	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39604	2006	28,350.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39604	2007	4,183.79	172.91	(408.60)	581.51	13.90%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%	1.79%
39604	2008	78,139.70	14,944.71	461.27	14,483.44	18.54%	18.30%	13.61%	13.61%	13.61%	13.61%	13.61%	13.61%	13.61%	13.61%
39604	2009	120,659.85	0.00	0.00	0.00	0.00%	7.29%	7.42%	6.51%	6.51%	6.51%	6.51%	6.51%	6.51%	6.51%
39604	2010	8,958.43	18,718.90	0.00	18,718.90	208.95%	14.44%	15.98%	15.94%	14.06%	14.06%	14.06%	14.06%	14.06%	14.06%
39604	2011	0.00	0.00	0.00	0.00	NA	208.95%	14.44%	15.98%	15.94%	14.06%	14.06%	14.06%	14.06%	14.06%
39604	2012	0.00	0.00	0.00	0.00	NA	NA	208.95%	14.44%	15.98%	15.94%	14.06%	14.06%	14.06%	14.06%
39604	2013	0.00	0.00	0.00	0.00	NA	NA	NA	208.95%	14.44%	15.98%	15.94%	14.06%	14.06%	14.06%
39604	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	208.95%	14.44%	15.98%	15.94%	14.06%	14.06%
39605	1996	0.00	0.00	0.00	0.00	NA									
39605	1997	0.00	0.00	0.00	0.00	NA	NA								
39605	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39605	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39605	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39605	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39605	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39605	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39605	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39605	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39605	2006	25,466.74	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39605	2007	3,362.06	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39605	2008	3,599.50	1,027.00	0.00	1,027.00	28.53%	14.75%	3.17%	3.17%	3.17%	3.17%	3.17%	3.17%	3.17%	3.17%
39605	2009	4,087.50	0.00	0.00	0.00	0.00%	13.36%	9.29%	2.81%	2.81%	2.81%	2.81%	2.81%	2.81%	2.81%
39605	2010	6,737.88	300.00	0.00	300.00	4.45%	2.77%	9.20%	7.46%	3.07%	3.07%	3.07%	3.07%	3.07%	3.07%
39605	2011	3,111.94	0.00	0.00	0.00	0.00%	3.05%	2.15%	7.57%	6.35%	2.86%	2.86%	2.86%	2.86%	2.86%
39605	2012	4,978.01	0.00	0.00	0.00	0.00%	0.00%	2.02%	1.59%	5.89%	5.13%	2.58%	2.58%	2.58%	2.58%
39605	2013	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	2.02%	1.59%	5.89%	5.13%	2.58%	2.58%	2.58%
39605	2014	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	2.02%	1.59%	5.89%	5.13%	2.58%	2.58%

Appendix D

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
396 Combine	1996	1,106.00	7,500.00	0.00	7,500.00	678.12%									
396 Combine	1997	0.00	1,900.00	356.00	1,544.00	NA	817.72%								
396 Combine	1998	1,515.00	520.00	0.00	520.00	34.32%	136.24%	364.90%							
396 Combine	1999	22,556.00	0.00	0.00	0.00	0.00%	2.16%	8.57%	37.99%						
396 Combine	2000	153,880.00	54,000.00	0.00	54,000.00	35.09%	30.61%	30.64%	31.51%	35.50%					
396 Combine	2001	1,617.00	0.00	0.00	0.00	0.00%	34.73%	30.33%	30.36%	31.22%	35.18%				
396 Combine	2002	278,879.00	22,479.00	0.00	22,479.00	8.06%	8.01%	17.61%	16.74%	16.80%	17.13%	18.72%			
396 Combine	2003	357,777.00	0.00	0.00	0.00	0.00%	3.53%	3.52%	9.65%	9.39%	9.43%	9.62%	10.53%		
396 Combine	2004	204,050.00	0.00	0.00	0.00	0.00%	0.00%	2.67%	2.67%	7.68%	7.51%	7.55%	7.70%	8.42%	
396 Combine	2005	42,281.00	12,485.86	0.00	12,485.86	29.53%	5.07%	2.07%	3.96%	3.95%	8.57%	8.38%	8.42%	8.57%	9.26%
396 Combine	2006	116,295.80	0.00	0.00	0.00	0.00%	7.87%	3.44%	1.73%	3.50%	3.49%	7.70%	7.56%	7.59%	7.72%
396 Combine	2007	59,161.83	172.91	(408.60)	581.51	0.98%	0.33%	6.00%	3.10%	1.68%	3.36%	3.35%	7.38%	7.24%	7.28%
396 Combine	2008	81,739.20	15,971.71	461.27	15,510.44	18.98%	11.42%	6.26%	9.54%	5.68%	3.32%	4.48%	4.47%	8.11%	7.97%
396 Combine	2009	125,074.44	0.00	0.00	0.00	0.00%	7.50%	6.05%	4.21%	6.73%	4.55%	2.90%	4.04%	4.03%	7.39%
396 Combine	2010	104,948.43	19,018.90	0.00	19,018.90	18.12%	8.27%	11.08%	9.47%	7.21%	8.99%	6.49%	4.36%	5.11%	5.11%
396 Combine	2011	3,111.94	0.00	0.00	0.00	0.00%	17.60%	8.16%	10.97%	9.39%	7.16%	8.94%	6.46%	4.35%	5.10%
396 Combine	2012	55,855.77	0.00	0.00	0.00	0.00%	0.00%	11.60%	6.58%	9.31%	8.17%	6.43%	8.09%	6.01%	4.14%
396 Combine	2013	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	11.60%	6.58%	9.31%	8.17%	6.43%	8.09%	6.01%
396 Combine	2014	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	11.60%	6.58%	9.31%	8.17%	6.43%	8.09%
39700	1996	2,141.00	0.00	0.00	0.00	0.00%									
39700	1997	1,536.00	0.00	0.00	0.00	0.00%	0.00%								
39700	1998	0.00	0.00	0.00	0.00	NA	0.00%	0.00%							
39700	1999	2,345.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%						
39700	2000	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%					
39700	2001	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%				
39700	2002	38,139.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
39700	2003	4,941.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
39700	2004	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39700	2005	32,436.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39700	2006	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39700	2007	919,963.60	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39700	2008	48,953.27	0.00	(2,227.94)	2,227.94	4.55%	0.23%	0.23%	0.22%	0.22%	0.22%	0.21%	0.21%	0.21%	0.21%
39700	2009	7,200.16	0.00	0.00	0.00	0.00%	3.97%	0.23%	0.23%	0.22%	0.22%	0.22%	0.21%	0.21%	0.21%
39700	2010	12,519.18	0.00	0.00	0.00	0.00%	0.00%	3.24%	0.23%	0.23%	0.22%	0.22%	0.22%	0.21%	0.21%
39700	2011	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	3.24%	0.23%	0.23%	0.22%	0.22%	0.22%	0.21%
39700	2012	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	3.24%	0.23%	0.23%	0.22%	0.22%	0.22%
39700	2013	441.02	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	3.22%	0.23%	0.23%	0.22%	0.22%
39700	2014	44,500.12	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.96%	0.22%	0.22%	0.21%
39701	1996	0.00	0.00	0.00	0.00	NA									
39701	1997	0.00	0.00	0.00	0.00	NA	NA								
39701	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39701	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39701	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39701	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39701	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39701	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39701	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39701	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39701	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39701	2007	1,198.22	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39701	2008	2,140.01	0.00	20.19	(20.19)	-0.94%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%
39701	2009	0.00	0.00	0.00	0.00	NA	-0.94%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%
39701	2010	0.00	0.00	0.00	0.00	NA	NA	-0.94%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%
39701	2011	0.00	0.00	0.00	0.00	NA	NA	NA	-0.94%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
39701	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-0.94%	-0.60%	-0.60%	-0.60%	-0.60%	-0.60%
39701	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-0.94%	-0.60%	-0.60%	-0.60%	-0.60%
39701	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-0.94%	-0.60%	-0.60%	-0.60%
39702	1996	0.00	0.00	0.00	0.00	NA									
39702	1997	0.00	0.00	0.00	0.00	NA	NA								
39702	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39702	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39702	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39702	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39702	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39702	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39702	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39702	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39702	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39702	2007	38,600.11	0.00	0.00	0.00	0.00%	NA	NA	NA	NA	NA	NA	NA	NA	NA
39702	2008	2,832.34	0.00	23.87	(23.87)	-0.84%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%
39702	2009	0.00	0.00	0.00	0.00	NA	NA	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%
39702	2010	0.00	0.00	0.00	0.00	NA	NA	NA	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%
39702	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%
39702	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-0.06%	-0.06%	-0.06%	-0.06%	-0.06%
39702	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-0.84%	-0.06%	-0.06%	-0.06%	-0.06%
39702	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-0.84%	-0.06%	-0.06%	-0.06%
39705	1996	0.00	0.00	0.00	0.00	NA									
39705	1997	0.00	0.00	0.00	0.00	NA	NA								
39705	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39705	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39705	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39705	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39705	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39705	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39705	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39705	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39705	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39705	2007	230,512.22	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39705	2008	15,407.88	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39705	2009	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39705	2010	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39705	2011	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39705	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39705	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39705	2014	66,315.61	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397 Combine	1996	2,141.00	0.00	0.00	0.00	0.00%									
397 Combine	1997	1,536.00	0.00	0.00	0.00	0.00%	0.00%								
397 Combine	1998	0.00	0.00	0.00	0.00	NA	0.00%	0.00%							
397 Combine	1999	2,345.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%						
397 Combine	2000	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%					
397 Combine	2001	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%				
397 Combine	2002	38,139.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
397 Combine	2003	4,941.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
397 Combine	2004	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
397 Combine	2005	32,436.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397 Combine	2006	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
397 Combine	2007	1,190,274.15	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
397 Combine	2008	69,333.50	0.00	(2,183.88)	2,183.88	3.15%	0.17%	0.17%	0.17%	0.17%	0.17%	0.16%	0.16%	0.16%	0.16%
397 Combine	2009	7,200.16	0.00	0.00	0.00	0.00%	2.85%	0.17%	0.17%	0.17%	0.17%	0.17%	0.16%	0.16%	0.16%
397 Combine	2010	12,519.18	0.00	0.00	0.00	0.00%	0.00%	2.45%	0.17%	0.17%	0.17%	0.17%	0.17%	0.16%	0.16%
397 Combine	2011	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	2.45%	0.17%	0.17%	0.17%	0.17%	0.17%	0.16%
397 Combine	2012	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	2.45%	0.17%	0.17%	0.17%	0.17%	0.17%
397 Combine	2013	441.02	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	2.44%	0.17%	0.17%	0.17%	0.17%
397 Combine	2014	110,815.73	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.09%	0.16%	0.16%	0.15%
39800	1996	0.00	0.00	0.00	0.00	NA									
39800	1997	0.00	0.00	0.00	0.00	NA	NA								
39800	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39800	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39800	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39800	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39800	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA			
39800	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA		
39800	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	
39800	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39800	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39800	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
39800	2008	125,948.40	2,665.16	157.29	2,507.87	1.99%	1.99%	1.99%	1.99%	1.99%	1.99%	1.99%	1.99%	1.99%	1.99%
39800	2009	27,604.50	0.00	1,112.60	(1,112.60)	-4.03%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%
39800	2010	154,966.61	2,236.00	3,717.65	(1,481.65)	-0.96%	-1.42%	-0.03%	-0.03%	-0.03%	-0.03%	-0.03%	-0.03%	-0.03%	-0.03%
39800	2011	45,141.29	0.00	191.70	(191.70)	-0.42%	-0.84%	-1.22%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%	-0.08%
39800	2012	131,827.69	0.00	562.83	(562.83)	-0.43%	-0.43%	-0.67%	-0.93%	-0.17%	-0.17%	-0.17%	-0.17%	-0.17%	-0.17%
39800	2013	213,313.93	0.00	235.04	(235.04)	-0.11%	-0.23%	-0.25%	-0.45%	-0.63%	-0.15%	-0.15%	-0.15%	-0.15%	-0.15%
39800	2014	211,668.92	0.00	327.50	(327.50)	-0.15%	-0.13%	-0.20%	-0.22%	-0.37%	-0.50%	-0.15%	-0.15%	-0.15%	-0.15%
39906	1996	0.00	0.00	0.00	0.00	NA									
39906	1997	0.00	0.00	0.00	0.00	NA	NA								
39906	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39906	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA						
39906	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA					
39906	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA				
39906	2002	190,623.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
39906	2003	158,354.00	2,788.00	0.00	2,788.00	1.76%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%		
39906	2004	176,848.00	0.00	0.00	0.00	0.00%	0.83%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	
39906	2005	0.00	0.00	0.00	0.00	NA	0.00%	0.83%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
39906	2006	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.83%	0.53%	0.53%	0.53%	0.53%	0.53%	0.53%
39906	2007	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.83%	0.53%	0.53%	0.53%	0.53%	0.53%
39906	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.83%	0.53%	0.53%	0.53%	0.53%
39906	2009	130,183.59	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.60%	0.42%	0.42%	0.42%
39906	2010	764,870.51	0.00	2,695.80	(2,695.80)	-0.35%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.25%	0.01%	0.01%	0.01%
39906	2011	0.00	0.00	0.00	0.00	NA	-0.35%	-0.30%	-0.30%	-0.30%	-0.30%	-0.30%	-0.25%	0.01%	0.01%
39906	2012	399,769.11	0.00	0.00	0.00	0.00%	0.00%	-0.23%	-0.21%	-0.21%	-0.21%	-0.21%	-0.21%	-0.18%	0.01%
39906	2013	1,182,003.38	0.00	2,933.56	(2,933.56)	-0.25%	-0.19%	-0.19%	-0.24%	-0.23%	-0.23%	-0.23%	-0.23%	-0.23%	-0.21%
39906	2014	1,680,400.45	0.00	3,755.07	(3,755.07)	-0.22%	-0.23%	-0.21%	-0.21%	-0.23%	-0.23%	-0.23%	-0.23%	-0.23%	-0.23%
39907	1996	0.00	0.00	0.00	0.00	NA									
39907	1997	0.00	0.00	0.00	0.00	NA	NA								
39907	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39907	1999	185,509.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%						
39907	2000	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%					
39907	2001	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%				
39907	2002	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
39907	2003	54,807.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		

ATMOS ENERGY - KENTUCKY DIVISION
Depreciation Study as of September 30, 2014
NET SALVAGE HISTORY

Account	TY	Retirements	Salvage	COR	Net Salvage	Net Salv. %	2-yr Net Salv. %	3-yr Net Salv. %	4-yr Net Salv. %	5-yr Net Salv. %	6-yr Net Salv. %	7-yr Net Salv. %	8-yr Net Salv. %	9-yr Net Salv. %	10-yr Net Salv. %
39907	2004	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39907	2005	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2006	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2007	9,399.38	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2008	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2009	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2010	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2013	233,448.29	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39907	2014	131.07	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39908	1996	0.00	0.00	0.00	0.00	NA									
39908	1997	0.00	0.00	0.00	0.00	NA	NA								
39908	1998	0.00	0.00	0.00	0.00	NA	NA	NA							
39908	1999	55,783.00	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%						
39908	2000	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%					
39908	2001	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%				
39908	2002	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%			
39908	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%		
39908	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
39908	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
39908	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
39908	2007	(176,149.83)	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39908	2008	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39908	2009	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39908	2010	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39908	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39908	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
39908	2013	272,695.67	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
39908	2014	15,499.34	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%