ATMOS ENERGY CORP
Form 10-Q
August 07, 2013

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

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

For the quarterly period ended June 30, 2013
or

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

For the transition period from to
Commission File Number 1-10042
Atmos Energy Corporation
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

Number of shares outstanding of each of the issuer's classes of common stock, as of August 2, 2013.

Class	Shares Outstanding
No Par Value	90,640,211

GLOSSARY OF KEY TERMS

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

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements
ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2013	September 30, 2012
	(Unaudited)	
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$7,494,175	$7,134,470
Less accumulated depreciation and amortization	1,652,960	1,658,866
Net property, plant and equipment	5,841,215	5,475,604
Current assets		
Cash and cash equivalents	31,979	64,239
Accounts receivable, net	350,237	234,526
Gas stored underground	209,101	256,415
Other current assets	90,936	272,782
Total current assets	682,253	827,962
Goodwill and intangible assets	740,814	740,847
Deferred charges and other assets	538,516	451,262
	$7,802,798	$7,495,675
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, 2013 — 90,639,520 shares; September 30, 2012 — 90,239,900 shares	$453	$451
Additional paid-in capital	1,757,059	1,745,467
Retained earnings	800,643	660,932
Accumulated other comprehensive income (loss)	23,289	(47,607)
Shareholders' equity	2,581,444	2,359,243
Long-term debt	2,455,593	1,956,305
Total capitalization	5,037,037	4,315,548
Current liabilities		
Accounts payable and accrued liabilities	229,876	215,229
Other current liabilities	348,706	489,665
Short-term debt	141,998	570,929
Current maturities of long-term debt	—	131
Total current liabilities	720,580	1,275,954
Deferred income taxes	1,197,274	1,015,083
Regulatory cost of removal obligation	360,578	381,164
Pension and postretirement liabilities	444,540	457,196
Deferred credits and other liabilities	42,789	50,730
	$7,802,798	$7,495,675

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30	
	2013	2012
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$467,144	$315,634
Regulated transmission and storage segment	74,041	67,073
Nonregulated segment	421,808	256,250
Intersegment eliminations	(105,058)	(62,543)
	857,935	576,414
Purchased gas cost		
Natural gas distribution segment	227,649	120,575
Regulated transmission and storage segment	—	—
Nonregulated segment	418,548	224,829
Intersegment eliminations	(104,759)	(62,161)
	541,438	283,243
Gross profit	316,497	293,171
Operating expenses		
Operation and maintenance	121,258	106,045
Depreciation and amortization	58,129	58,956
Taxes, other than income	50,714	46,624
Total operating expenses	230,101	211,625
Operating income	86,396	81,546
Miscellaneous expense	(467)	(2,075)
Interest charges	32,741	34,909
Income from continuing operations before income taxes	53,188	44,562
Income tax expense	19,714	16,548
Income from continuing operations	33,474	28,014
Income from discontinued operations, net of tax ($0 and $1,792)	—	3,118
Gain on sale of discontinued operations, net of tax ($2,909 and $0)	5,294	—
Net income	$38,768	$31,132
Basic earnings per share		
Income per share from continuing operations	$0.37	$0.31
Income per share from discontinued operations	0.06	0.03
Net income per share — basic	$0.43	$0.34
Diluted earnings per share		
Income per share from continuing operations	$0.36	$0.31
Income per share from discontinued operations	0.06	0.03
Net income per share — diluted	$0.42	$0.34
Cash dividends per share	$0.350	$0.345
Weighted average shares outstanding:		
Basic	90,603	90,118
Diluted	91,550	90,993

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	Nine Months Ended June 30	
	2013	2012
	(Unaudited) (In thousands, except per share data)	
Operating revenues		
Natural gas distribution segment	$2,039,107	$1,862,814
Regulated transmission and storage segment	196,570	181,869
Nonregulated segment	1,250,650	1,071,189
Intersegment eliminations	(285,241)	(229,955)
	3,201,086	2,885,917
Purchased gas cost		
Natural gas distribution segment	1,172,975	1,011,832
Regulated transmission and storage segment	—	—
Nonregulated segment	1,200,624	1,028,592
Intersegment eliminations	(284,123)	(228,857)
	2,089,476	1,811,567
Gross profit	1,111,610	1,074,350
Operating expenses		
Operation and maintenance	338,871	329,989
Depreciation and amortization	174,888	176,742
Taxes, other than income	146,355	144,170
Total operating expenses	660,114	650,901
Operating income	451,496	423,449
Miscellaneous income (expense)	1,943	(3,585)
Interest charges	96,594	107,278
Income from continuing operations before income taxes	356,845	312,586
Income tax expense	133,683	120,104
Income from continuing operations	223,162	192,482
Income from discontinued operations, net of tax ($3,986 and $9,339)	7,202	16,268
Gain on sale of discontinued operations, net of tax ($2,909 and $0)	5,294	—
Net income	$235,658	$208,750
Basic earnings per share		
Income per share from continuing operations	$2.46	$2.13
Income per share from discontinued operations	0.14	0.18
Net income per share — basic	$2.60	$2.31
Diluted earnings per share		
Income per share from continuing operations	$2.43	$2.10
Income per share from discontinued operations	0.14	0.18
Net income per share — diluted	$2.57	$2.28
Cash dividends per share	$1.050	$1.035
Weighted average shares outstanding:		
Basic	90,497	90,131
Diluted	91,445	91,006

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	
	2013	2012	2013	2012
	(Unaudited) (In thousands)			
Net income	$38,768	$31,132	$235,658	$208,750
Other comprehensive income (loss), net of tax				
Net unrealized holding gains (losses) on available-for-sale securities, net of tax of $(202), $(523), $(532) and $1,194	(348)	(888)	(921)	2,059
Cash flow hedges:				
Amortization and unrealized gain (loss) on interest rate agreements, net of tax of $17,865, $(18,399), $38,427 and $(9,995)	31,079	(31,328)	66,852	(17,019)
Net unrealized gains (losses) on commodity cash flow hedges, net of tax of $(2,243), $11,401, $3,174 and $(2,595)	(3,508)	17,830	4,965	(4,060)
Total other comprehensive income (loss)	27,223	(14,386)	70,896	(19,020)
Total comprehensive income	$65,991	$16,746	$306,554	$189,730

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended June 30	
	2013	2012
	(Unaudited) (In thousands)	
Cash Flows From Operating Activities		
Net income	$235,658	$208,750
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of discontinued operations	(8,203)	—
Depreciation and amortization:		
Charged to depreciation and amortization	176,737	183,884
Charged to other accounts	446	310
Deferred income taxes	130,365	120,713
Other	14,460	22,386
Net assets / liabilities from risk management activities	(6,386)	12,759
Net change in operating assets and liabilities	(33,502)	(29,996)
Net cash provided by operating activities	509,575	518,806
Cash Flows From Investing Activities		
Capital expenditures	(582,473)	(497,374)
Proceeds from the sale of discontinued operations	153,023	—
Other, net	(3,139)	(4,247)
Net cash used in investing activities	(432,589)	(501,621)
Cash Flows From Financing Activities		
Net decrease in short-term debt	(435,084)	(6,688)
Net proceeds from issuance of long-term debt	493,793	—
Settlement of Treasury lock agreements	(66,626)	—
Repayment of long-term debt	(131)	(2,369)
Cash dividends paid	(96,060)	(94,338)
Repurchase of common stock	—	(12,535)
Repurchase of equity awards	(5,146)	(5,219)
Issuance of common stock	8	251
Net cash used in financing activities	(109,246)	(120,898)
Net decrease in cash and cash equivalents	(32,260)	(103,713)
Cash and cash equivalents at beginning of period	64,239	131,419
Cash and cash equivalents at end of period	$31,979	$27,706

See accompanying notes to condensed consolidated financial statements.

ATMOS ENERGY CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
June 30, 2013

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. For the fiscal year ended September 30, 2012, our regulated businesses generated over 95 percent of our consolidated net income.

Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which at June 30, 2013, covered service areas located in eight states. In addition, we transport natural gas for others through our distribution system. On April 1, 2013, we completed the divestiture of our natural gas distribution operations in Georgia, representing approximately 64,000 customers. Our regulated businesses also include our regulated pipeline and storage operations, which include the transportation of natural gas to our distribution system and the management of our underground storage facilities. Our regulated businesses are subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate.

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

We operate the Company through the following three segments:

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

2. Unaudited Financial Information

These consolidated interim-period financial statements have been prepared in accordance with accounting principles generally accepted in the United States on the same basis as those used for the Company's audited consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. 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, 2012. Because of seasonal and other factors, the results of operations for the nine-month period ended June 30, 2013 are not indicative of our results of operations for the full 2013 fiscal year, which ends September 30, 2013.

We have evaluated subsequent events from the June 30, 2013 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission (SEC). Except as noted in Note 10, 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, 2012.

During the second quarter of fiscal 2013, we completed our annual goodwill impairment assessment. Based on the assessment performed, we determined that our goodwill was not impaired.

Due to the April 1, 2013 sale of our Georgia distribution operations, at June 30, 2013, the financial results for this service area are shown in discontinued operations. Accordingly, certain prior-year amounts have been reclassified to conform with the current-year presentation.

During the nine months ended June 30, 2013, two new accounting standards were announced that will become applicable to the Company in future periods. The first standard clarifies the enhanced disclosure of offsetting arrangements for financial instruments that will become effective for us for annual and interim periods beginning on October 1, 2013. The adoption of this standard should not have an impact on our financial position, results of operations or cash flows. The second standard, which became effective during our second fiscal quarter, requires the presentation of amounts reclassified out of accumulated other comprehensive income by component as well as significant amounts reclassified out of accumulated other comprehensive income by the respective line item in the statement of net income. We have presented the disclosures relating to reclassifications out of accumulated other comprehensive income in Note 4. The adoption of this standard did not have an impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the nine months ended June 30, 2013.

Regulatory assets and liabilities

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

Significant regulatory assets and liabilities as of June 30, 2013 and September 30, 2012 included the following:

	June 30, 2013	September 30, 2012
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs[1]	$280,136	$296,160
Merger and integration costs, net	5,376	5,754
Deferred gas costs	1,271	31,359
Regulatory cost of removal asset	6,058	10,500
Rate case costs	6,207	4,661
Deferred franchise fees	242	2,714
Texas Rule 8.209[2]	21,351	5,370
APT annual adjustment mechanism	5,167	4,539
Other	1,935	7,262
	$327,743	$368,319
Regulatory liabilities:		
Deferred gas costs	$30,773	$23,072
Deferred franchise fees	2,097	—
Regulatory cost of removal obligation	426,656	459,688
Other	5,398	5,637
	$464,924	$488,397

(1) Includes $15.5 million and $7.6 million of pension and postretirement expense deferred pursuant to regulatory authorization.

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

The amounts above do not include regulatory assets and liabilities related to our Georgia operations, which were classified as assets held for sale at September 30, 2012 as discussed in Note 6. As of June 30, 2013 we did not have any assets or liabilities classified as held for sale due to the sale of substantially all of our Georgia assets on April 1, 2013.

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

3. Financial Instruments

We use financial instruments to mitigate commodity price risk and interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. The accounting for these financial instruments is fully described in Note 2 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. During the nine months ended June 30, 2013 there were no changes in our objectives, strategies and accounting for these financial instruments. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

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

Regulated Commodity Risk Management Activities

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

Our natural gas distribution gas supply department is responsible for executing this segment’s commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2012-2013 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 33 percent, or 22.8 Bcf of the winter flowing gas requirements. We have not designated these financial instruments as hedges for accounting purposes.

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

Nonregulated Commodity Risk Management Activities

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

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

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 58 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in asset optimization activities in our nonregulated segment.

Our nonregulated operations also use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges for accounting purposes.

Interest Rate Risk Management Activities

We have periodically managed interest rate risk by entering into financial instruments to fix the Treasury yield component of the interest cost associated with anticipated financings. Prior to fiscal 2012, we used only Treasury locks to mitigate interest rate risk; however, beginning in the fourth quarter of fiscal 2012 we started utilizing interest rate swaps and forward starting interest rate swaps to manage this risk.

In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $350 million out of a total $500 million of senior notes that were issued on January 11, 2013. This offering is discussed in Note 7. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on January 8, 2013 with a payment of $66.6 million to the counterparties due to a decrease in the 30-year Treasury rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the $66.6 million unrealized loss was recorded as a component of accumulated other comprehensive income and is being recognized as a component of interest expense over the 30-year life of the senior notes.

In the fourth quarter of fiscal 2012, we entered into an interest rate swap to fix the LIBOR component of our $260 million short-term financing facility that terminated on December 27, 2012. We recorded an immaterial loss upon settlement of the swap, which was recorded as a component of interest expense as we did not designate the interest rate swap as a hedge.

In October 2012, we entered into forward starting interest rate swaps to fix the Treasury yield component associated with the anticipated issuance of $500 million and $250 million unsecured senior notes in fiscal 2015 and fiscal 2017, which we designated as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the forward starting interest rate swaps are being recorded as a component of accumulated other comprehensive income (loss). When the forward starting interest rate swaps settle, the realized gain or loss will be recorded as a component of accumulated other comprehensive income (loss) and recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred is reported as a component of interest expense.

In prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost of financing various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. As of June 30, 2013, the remaining amortization periods for the settled Treasury locks extend through fiscal 2043.

Quantitative Disclosures Related to Financial Instruments

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

As of June 30, 2013, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of June 30, 2013, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(22,250)
	Cash Flow	—	26,520
	Not designated	14,649	75,520
		14,649	79,790

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, 2013 and September 30, 2012. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $14.3 million and

$23.7 million of cash held on deposit in margin accounts as of June 30, 2013 and September 30, 2012 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our condensed consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 5.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
June 30, 2013				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$—	$ 12,250	$ 12,250
Noncurrent commodity contracts	Deferred charges and other assets	84,432	401	84,833
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(13,771)	(13,771)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(1,912)	(1,912)
Total		84,432	(3,032)	81,400
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	2,015	68,972	70,987
Noncurrent commodity contracts	Deferred charges and other assets	1,035	49,651	50,686
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(1,094)	(69,710)	(70,804)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(50,204)	(50,204)
Total		1,956	(1,291)	665
Total Financial Instruments		$ 86,388	$ (4,323)	$ 82,065

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2012				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$—	$ 19,301	$ 19,301
Noncurrent commodity contracts	Deferred charges and other assets	—	1,923	1,923
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(85,040)	(23,787)	(108,827)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(4,999)	(4,999)
Total		(85,040)	(7,562)	(92,602)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets[(1)]	7,082	98,393	105,475
Noncurrent commodity contracts	Deferred charges and other assets	2,283	60,932	63,215
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[(2)]	(585)	(99,824)	(100,409)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(67,062)	(67,062)
Total		8,780	(7,561)	1,219
Total Financial Instruments		$ (76,260)	$ (15,123)	$ (91,383)

(1) Other current assets not designated as hedges in our natural gas distribution segment include $0.1 million related to risk management assets that were classified as assets held for sale at September 30, 2012.

(2) Other current liabilities not designated as hedges in our natural gas distribution segment include $0.3 million related to risk management liabilities that were classified as liabilities held for sale at September 30, 2012.

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the three months ended June 30, 2013 and 2012 we recognized a gain (loss) arising from fair value and cash flow hedge ineffectiveness of $(0.4) million and $19.0 million. For the nine months ended June 30, 2013 and 2012 we recognized gains arising from fair value and cash flow hedge ineffectiveness of $17.3 million and $21.2 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 and nine months ended June 30, 2013 and 2012 is presented below.

	Three Months Ended June 30	
	2013	2012
	(In thousands)	
Commodity contracts	$14,453	$(14,942)
Fair value adjustment for natural gas inventory designated as the hedged item	(15,143)	34,296
Total (increase) decrease in purchased gas cost	$(690)	$19,354
The (increase) decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$(2,361)	$2,077
Timing ineffectiveness	1,671	17,277
	$(690)	$19,354

	Nine Months Ended June 30	
	2013	2012
	(In thousands)	
Commodity contracts	$3,921	$38,211
Fair value adjustment for natural gas inventory designated as the hedged item	13,261	(16,039)
Total decrease in purchased gas cost	$17,182	$22,172
The decrease in purchased gas cost is comprised of the following:		
Basis ineffectiveness	$(1,143)	$2,179
Timing ineffectiveness	18,325	19,993
	$17,182	$22,172

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. We did not record a writedown for nonqualifying natural gas inventory for the nine months ended June 30, 2013. During the nine months ended June 30, 2012, we recorded a $1.7 million charge to write down nonqualifying natural gas inventory to 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, 2013 and 2012 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

	Three Months Ended June 30, 2012		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$(19,534)	$(19,534)
Loss arising from ineffective portion of commodity contracts	—	(328)	(328)
Total impact on purchased gas cost	—	(19,862)	(19,862)
Loss on settled interest rate agreements reclassified from AOCI into interest expense	(502)	—	(502)
Total Impact from Cash Flow Hedges	$(502)	$(19,862)	$(20,364)

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

	Nine Months Ended June 30, 2012		
	Natural Gas Distribution	Nonregulated	Consolidated
	(In thousands)		
Loss reclassified from AOCI for effective portion of commodity contracts	$—	$(52,358)	$(52,358)
Loss arising from ineffective portion of commodity contracts	—	(996)	(996)
Total impact on purchased gas cost	—	(53,354)	(53,354)
Loss on settled interest rate agreements reclassified from AOCI into interest expense	(1,506)	—	(1,506)
Total Impact from Cash Flow Hedges	$(1,506)	$(53,354)	$(54,860)

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, 2013 and 2012. The amounts included in the table below exclude gains and losses arising from ineffectiveness because those amounts are immediately recognized in the income statement as incurred.

	Three Months Ended June 30		Nine Months Ended June 30	
	2013	2012	2013	2012
	(In thousands)			
Increase (decrease) in fair value:				
Interest rate agreements	$30,408	$(31,644)	$65,308	$(17,968)
Forward commodity contracts	(3,168)	5,914	(1,015)	(35,998)
Recognition of (gains) losses in earnings due to settlements:				
Interest rate agreements	671	316	1,544	949
Forward commodity contracts	(340)	11,916	5,980	31,938
Total other comprehensive income (loss) from hedging, net of tax(1)	$27,571	$(13,498)	$71,817	$(21,079)

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

Deferred gains (losses) recorded in accumulated other comprehensive income (AOCI) associated with our interest rate agreements are recognized in earnings as they are amortized over the terms of the underlying debt instruments, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of June 30, 2013. However, the table below does not include the expected recognition in earnings of our outstanding interest rate agreements as those instruments have not yet settled.

	Interest Rate Agreements	Commodity Contracts	Total
	(In thousands)		
Next twelve months	$(2,686)	$(3,133)	$(5,819)
Thereafter	(28,350)	(897)	(29,247)
Total(1)	$(31,036)	$(4,030)	$(35,066)

(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, 2013 and 2012 was an increase (decrease) in gross profit of $(8.4) million and $11.2 million. For the nine months ended June 30, 2013 and 2012 gross profit decreased $1.7 million and $3.8 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

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

4. Accumulated Other Comprehensive Income

We record deferred gains (losses) in accumulated other comprehensive income (AOCI) related to available-for-sale securities, interest rate agreement cash flow hedges and commodity contract cash flow hedges. Deferred gains (losses) for our available-for-sale securities and commodity contract cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate agreement cash flow hedges are recognized in earnings as they are amortized. The following table provides 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, 2012	$5,661	$(44,273)	$(8,995)	$(47,607)
Other comprehensive income before reclassifications	449	65,308	(1,015)	64,742
Amounts reclassified from accumulated other comprehensive income	(1,370)	1,544	5,980	6,154
Net current-period other comprehensive income	(921)	66,852	4,965	70,896
June 30, 2013	$4,740	$22,579	$(4,030)	$23,289

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

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

	Nine Months Ended June 30, 2013	
Accumulated Other Comprehensive Income Components	Amount Reclassified from Accumulated Other Comprehensive Income	Affected Line Item in the Statement of Income
	(In thousands)	
Available-for-sale securities	$2,158	Operation and maintenance expense
	2,158	Total before tax
	(788)	Tax expense
	$1,370	Net of tax
Cash flow hedges		
Interest rate agreements	$(2,432)	Interest charges
Commodity contracts	(9,803)	Purchased gas cost
	(12,235)	Total before tax
	4,711	Tax benefit
	$(7,524)	Net of tax
Total reclassifications	$(6,154)	Net of tax

5. 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, 2012. During the three and nine months ended June 30, 2013, there were no changes in these methods.

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about fair value measurements of the assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 9 to the financial statements in our Annual Report on Form 10-K for the fiscal year ending September 30, 2012.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1), with the lowest priority given to unobservable inputs (Level 3).

The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2013 and September 30, 2012. 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, 2013
	(In thousands)				
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$87,482	$—	$—	$87,482
Nonregulated segment	1,196	130,078	—	(119,278)	11,996
Total financial instruments	1,196	217,560	—	(119,278)	99,478
Hedged portion of gas stored underground	76,706	—	—	—	76,706
Available-for-sale securities					
Money market funds	—	5,122	—	—	5,122
Registered investment companies	39,051	—	—	—	39,051
Bonds	—	27,473	—	—	27,473
Total available-for-sale securities	39,051	32,595	—	—	71,646
Total assets	$116,953	$250,155	$—	$(119,278)	$247,830
Liabilities:					
Financial instruments					
Natural gas distribution segment	$—	$1,094	$—	$—	$1,094
Nonregulated segment	179	135,418	—	(133,530)	2,067
Total liabilities	$179	$136,512	$—	$(133,530)	$3,161

17

	Quoted Prices in Active Markets (Level 1) (In thousands)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2012
Assets:					
Financial instruments					
Natural gas distribution segment	$—	$9,365	$—	$—	$9,365
Nonregulated segment	714	179,835	—	(162,776)	17,773
Total financial instruments	714	189,200	—	(162,776)	27,138
Hedged portion of gas stored underground	67,192	—	—	—	67,192
Available-for-sale securities					
Money market funds	—	1,634	—	—	1,634
Registered investment companies	40,212	—	—	—	40,212
Bonds	—	22,552	—	—	22,552
Total available-for-sale securities	40,212	24,186	—	—	64,398
Total assets	$108,118	$213,386	$—	$(162,776)	$158,728
Liabilities:					
Financial instruments					
Natural gas distribution segment	$—	$85,625	$—	$—	$85,625
Nonregulated segment	4,563	191,109	—	(186,451)	9,221
Total liabilities	$4,563	$276,734	$—	$(186,451)	$94,846

(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, 2013, we had $14.3 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $2.5 million was used to offset current risk management liabilities under master netting arrangements and the remaining $11.8 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, 2012 we had $23.7 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $5.9 million was used to offset current risk management liabilities under master netting arrangements and the remaining $17.8 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 June 30, 2013				
Domestic equity mutual funds	$26,993	$6,611	$—	$33,604
Foreign equity mutual funds	4,536	925	(14)	5,447
Bonds	27,390	132	(49)	27,473
Money market funds	5,122	—	—	5,122
	$64,041	$7,668	$(63)	$71,646
As of September 30, 2012				
Domestic equity mutual funds	$25,779	$8,183	$—	$33,962
Foreign equity mutual funds	5,568	682	—	6,250
Bonds	22,358	196	(2)	22,552
Money market funds	1,634	—	—	1,634
	$55,339	$9,061	$(2)	$64,398

At June 30, 2013 and September 30, 2012, our available-for-sale securities included $44.2 million and $41.8 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans. At June 30, 2013, we maintained investments in bonds that have contractual maturity dates ranging from July 2013 through December 2019. During the nine months ended June 30, 2013, we recognized a net gain of $2.2 million on the sale of certain assets in the rabbi trusts.

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

Other Fair Value Measures

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations, which are considered Level 1 fair value measurements for debt instruments with a recent, observable trade or Level 2 fair value measurements for debt instruments where fair value is determined using the most recent available quoted market price. The following table presents the carrying value and fair value of our debt as of June 30, 2013:

	June 30, 2013
	(In thousands)
Carrying Amount	$2,460,000
Fair Value	$2,707,340

6. Discontinued Operations

On April 1, 2013, we completed the sale of substantially all of our natural gas distribution assets and certain related nonregulated assets located in Georgia to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million. The sale was previously announced on August 8, 2012. In connection with the sale, we recognized a net of tax gain of $5.3 million.

As required under generally accepted accounting principles, the operating results of our Georgia operations have been aggregated and reported on the condensed consolidated statements of income as income from discontinued operations, net of income tax. For the three months ended June 30, 2013, net income from discontinued operations includes the aforementioned gain on sale, while for the nine months ended June 30, 2013, net income from discontinued operations includes the operating results of our Georgia operations and the gain on sale. For the three and nine months ended June 30, 2012, net income from discontinued operations includes the operating results of our Georgia operations and the operating results of our Missouri, Illinois and Iowa operations that were sold on August 1, 2012. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Georgia operations are classified as "held for sale" in other current assets and liabilities in our condensed consolidated balance sheets at September 30, 2012. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.
The following table presents statement of income data related to discontinued operations.

	Three Months Ended June 30		Nine Months Ended June 30	
	2013	2012	2013	2012
	(In thousands)			
Operating revenues	$—	$18,162	$37,962	$103,107
Purchased gas cost	—	6,803	21,464	57,936
Gross profit	—	11,359	16,498	45,171
Operating expenses	—	6,522	5,858	20,069
Operating income	—	4,837	10,640	25,102
Other nonoperating income	—	73	548	505
Income from discontinued operations before income taxes	—	4,910	11,188	25,607
Income tax expense	—	1,792	3,986	9,339
Income from discontinued operations	—	3,118	7,202	16,268
Gain on sale of discontinued operations, net of tax	5,294	—	5,294	—
Net income from discontinued operations	$5,294	$3,118	$12,496	$16,268

The following table presents balance sheet data related to assets held for sale. At September 30, 2012 assets held for sale include assets and liabilities associated with our Georgia operations. At June 30, 2013 we did not have any assets or liabilities held for sale.

	September 30, 2012
	(In thousands)
Net plant, property & equipment	$142,865
Gas stored underground	4,688
Other current assets	6,931
Deferred charges and other assets	87
Assets held for sale	$154,571
Accounts payable and accrued liabilities	$2,114
Other current liabilities	3,776
Regulatory cost of removal	3,257
Deferred credits and other liabilities	2,426
Liabilities held for sale	$11,573

7. Debt

The nature and terms of our debt instruments and credit facilities are described in detail in Note 7 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. Except as noted below, there were no material changes in the terms of our debt instruments during the nine months ended June 30, 2013.

Long-term debt

Long-term debt at June 30, 2013 and September 30, 2012 consisted of the following:

	June 30, 2013	September 30, 2012
	(In thousands)	
Unsecured 4.95% Senior Notes, due October 2014	$500,000	$500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	400,000
Unsecured 4.15% Senior Notes, due 2043	500,000	—
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
Rental property term note due in installments through 2013	—	131
Total long-term debt	2,460,000	1,960,131
Less:		
Original issue discount on unsecured senior notes and debentures	4,407	3,695
Current maturities	—	131
	$2,455,593	$1,956,305

Our $250 million Unsecured 5.125% Senior Notes were originally scheduled to mature in January 2013. On August 28, 2012 we redeemed these notes with proceeds received through the issuance of commercial paper. On September 27, 2012, we entered into a $260 million short-term financing facility that was scheduled to mature on February 1, 2013 to repay the commercial paper borrowings utilized to redeem the Unsecured 5.125% Senior Notes. The short-term facility was repaid with the proceeds received through the issuance of 30-year unsecured senior notes on January 11, 2013, as discussed below.

We issued $500 million Unsecured 4.15% Senior Notes on January 11, 2013. The effective interest rate of these notes is 4.64 percent, after giving effect to offering costs and the settlement of the associated Treasury lock agreements discussed in Note 3. Of the net proceeds of approximately $494 million, $260 million was used to repay our short-term financing facility. The remaining $234 million of net proceeds was used to partially repay our commercial paper borrowings and for general corporate purposes.

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 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 $750 million commercial paper program, four committed revolving credit facilities and one uncommitted revolving credit facility with third-party lenders. On December 7, 2012, we amended the terms of our former $750 million unsecured credit facility to increase the borrowing capacity to $950 million, with an accordion feature, which, if utilized, would increase the borrowing capacity to $1.2 billion. The amendment also permits us to obtain same-day funding on base rate loans. There were no other material changes to the credit facility. These facilities provide approximately $1.0 billion of working capital funding. At June 30, 2013 and September 30, 2012, a total of $142.0 million and $310.9 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 $989 million of working capital funding, including a five-year $950 million unsecured facility, a $25 million unsecured facility and a $14 million unsecured revolving credit facility, which is used primarily to issue letters of credit. The $25 million facility was renewed on April 1, 2013. Due to outstanding letters of credit, the total amount available to us under our $14 million revolving credit facility was $8.2 million at June 30, 2013.

In addition to these third-party facilities, our regulated operations have a $500 million intercompany revolving credit facility with AEH, which bears interest at the lower of (i) the Eurodollar rate under the five-year revolving credit facility or

21

(ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2013.

Nonregulated Operations

Prior to December 5, 2012, Atmos Energy Marketing, LLC (AEM), which is wholly owned by AEH, had a three-year $200 million committed revolving credit facility, expiring in December 2014, with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility was primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs. This facility was collateralized by substantially all of the assets of AEM and was guaranteed by AEH. AEM terminated the committed revolving credit facility on December 5, 2012, to reduce external credit expense. AEM incurred no penalties in connection with the termination. This facility was replaced with two $25 million, 364-day bilateral credit facilities, one of which is a committed facility. These facilities are used primarily to issue letters of credit. Due to outstanding letters of credit, the total amount available to us under these bilateral credit facilities was $38.6 million at June 30, 2013.

AEH has a $500 million intercompany demand credit facility with AEC. This facility bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2013.

Shelf Registration

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

Debt Covenants

The availability of funds under our regulated credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At June 30, 2013, our total-debt-to-total-capitalization ratio, as defined in the agreements, was 52 percent. In addition, both the interest margin and the fee that we pay on unused amounts under each 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 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, 2013. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

8. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities), we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock units, for which vesting is predicated solely on the passage of time granted under our 1998 Long-Term Incentive Plan, are considered to be participating securities. 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, 2013 and 2012 are calculated as follows:

	Three Months Ended June 30		Nine Months Ended June 30	
	2013	2012	2013	2012
	(In thousands, except per share amounts)			
Basic Earnings Per Share from continuing operations				
Income from continuing operations	$33,474	$28,014	$223,162	$192,482
Less: Income from continuing operations allocated to participating securities	91	116	760	808
Income from continuing operations available to common shareholders	$33,383	$27,898	$222,402	$191,674
Basic weighted average shares outstanding	90,603	90,118	90,497	90,131
Income from continuing operations per share — Basic	$0.37	$0.31	$2.46	$2.13
Basic Earnings Per Share from discontinued operations				
Income from discontinued operations	$5,294	$3,118	$12,496	$16,268
Less: Income from discontinued operations allocated to participating securities	14	13	43	68
Income from discontinued operations available to common shareholders	$5,280	$3,105	$12,453	$16,200
Basic weighted average shares outstanding	90,603	90,118	90,497	90,131
Income from discontinued operations per share — Basic	$0.06	$0.03	$0.14	$0.18
Net income per share — Basic	$0.43	$0.34	$2.60	$2.31

	Three Months Ended June 30		Nine Months Ended June 30	
	2013	2012	2013	2012
	(In thousands, except per share amounts)			
Diluted Earnings Per Share from continuing operations				
Income from continuing operations available to common shareholders	$33,383	$27,898	$222,402	$191,674
Effect of dilutive stock options and other shares	—	—	5	4
Income from continuing operations available to common shareholders	$33,383	$27,898	$222,407	$191,678
Basic weighted average shares outstanding	90,603	90,118	90,497	90,131
Additional dilutive stock options and other shares	947	875	948	875
Diluted weighted average shares outstanding	91,550	90,993	91,445	91,006
Income from continuing operations per share — Diluted	$0.36	$0.31	$2.43	$2.10
Diluted Earnings Per Share from discontinued operations				
Income from discontinued operations available to common shareholders	$5,280	$3,105	$12,453	$16,200
Effect of dilutive stock options and other shares	—	—	—	—
Income from discontinued operations available to common shareholders	$5,280	$3,105	$12,453	$16,200
Basic weighted average shares outstanding	90,603	90,118	90,497	90,131
Additional dilutive stock options and other shares	947	875	948	875
Diluted weighted average shares outstanding	91,550	90,993	91,445	91,006
Income from discontinued operations per share — Diluted	$0.06	$0.03	$0.14	$0.18
Net income per share — Diluted	$0.42	$0.34	$2.57	$2.28

There were no out-of-the-money stock options excluded from the computation of diluted earnings per share for the three and nine months ended June 30, 2013 and 2012 as their exercise price was less than the average market price of the common stock during those periods.

Share Repurchase Program

We did not repurchase any shares during the nine months ended June 30, 2013 as part of our 2011 share repurchase program. For the nine months ended June 30, 2012, we repurchased and retired 387,991 shares for an aggregate value of $12.5 million as part of the program.

9. 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, 2013 and 2012 are presented in the following table. Most of these costs are recoverable through our gas distribution rates; however, a portion of these costs is capitalized into our gas distribution rate base. The remaining costs are recorded as a component of operation and maintenance expense. On April 1, 2013, due to the retirement of certain executives, we recognized a curtailment loss of $3.2 million associated with our Supplemental Executive Benefit Plan and revalued the net periodic pension cost for the remainder of fiscal 2013. The revaluation of the net periodic pension cost resulted in an increase in the discount rate, effective April 1, 2013, to 4.21 percent, which will reduce our net periodic pension cost by approximately $0.1 million for the remainder of the fiscal year. All other actuarial assumptions remained the same.

	Three Months Ended June 30			
	Pension Benefits		Other Benefits	
	2013	2012	2013	2012
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$5,194	$4,297	$4,700	$4,089
Interest cost	6,019	6,677	3,241	3,465
Expected return on assets	(5,739)	(5,368)	(997)	(651)
Amortization of transition asset	—	—	271	377
Amortization of prior service cost	(35)	(35)	(363)	(362)
Amortization of actuarial loss	5,432	4,142	1,049	662
Curtailment	3,161	—	—	—
Net periodic pension cost	$14,032	$9,713	$7,901	$7,580

	Nine Months Ended June 30			
	Pension Benefits		Other Benefits	
	2013	2012	2013	2012
	(In thousands)			
Components of net periodic pension cost:				
Service cost	$15,599	$12,893	$14,100	$12,265
Interest cost	18,067	20,032	9,723	10,396
Expected return on assets	(17,216)	(16,105)	(2,991)	(1,955)
Amortization of transition asset	—	—	811	1,133
Amortization of prior service cost	(106)	(106)	(1,088)	(1,087)
Amortization of actuarial loss	16,555	12,427	3,147	1,986
Curtailment	3,161	—	—	—
Net periodic pension cost	$36,060	$29,141	$23,702	$22,738

The assumptions used to develop our net periodic pension cost for the three and nine months ended June 30, 2013 and 2012 are as follows:

	Supplemental Executive Benefit Plans		Pension Benefits		Other Benefits	
	2013	2012	2013	2012	2013	2012
Discount rate	4.21 %	5.05 %	4.04 %	5.05 %	4.04 %	5.05 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	3.50 %	N/A	N/A
Expected return on plan assets	N/A	N/A	7.75 %	7.75 %	4.70 %	4.70 %

The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. Generally, our funding policy has been to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2013. During the first nine months of fiscal 2013, we contributed $21.0 million to our defined benefit plans and we anticipate contributing approximately $12 million during the remainder of the fiscal year.

We contributed $19.5 million to our other post-retirement benefit plans during the nine months ended June 30, 2013. We expect to contribute a total of approximately $5 million to $10 million to these plans during the remainder of the fiscal year.

10. Commitments and Contingencies

Litigation and Environmental Matters

With respect to the specific litigation and environmental-related matters or claims that were disclosed in Note 13 to the financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012, except as noted below, there were no material changes in the status of such litigation and environmental-related matters or claims during the nine months ended June 30, 2013.

Kentucky Litigation

Since September 2009, Atmos Energy and two subsidiaries of AEH, Atmos Energy Marketing, LLC (AEM) and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

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

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

In an opinion handed down on January 25, 2013, the Court of Appeals overturned the $28.5 million jury verdict returned against the Atmos Entities. In a unanimous decision by a three-judge panel, the Court of Appeals reversed the claims asserted by the landowners and investors/working interest owners. The Court of Appeals concluded that all of such claims that the Atmos Entities appealed should have been dismissed by the trial court as a matter of law. The Court of Appeals let stand the jury verdict on one claim that Atmos Energy and our subsidiaries chose not to appeal, which was a trespass claim. The jury had

awarded a total of $10,000 in compensatory damages to one landowner on that claim. The Court of Appeals vacated all of the other damages awarded by the jury and remanded the case to the trial court for a new trial, solely on the issue of whether punitive damages should be awarded to that landowner and, if so, in what amount.
The investors/working interest owners, on February 25, 2013, and the landowners, on March 19, 2013, each filed with the Supreme Court of Kentucky, separate motions for discretionary review of the opinion of the Court of Appeals. We filed a response to the motion filed by the investors/working owners on March 27, 2013 and to the landowners' motion on April 17, 2013. The decision of the Court of Appeals will not become final until the appellate process is completed. We had previously accrued what we believed to be an adequate amount for the anticipated resolution of this matter and we will continue to maintain this amount in legal reserves until the appellate process in this case has been completed. We continue to believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.
In addition, in a related matter, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky, Atmos Energy Corporation et al.vs. Resource Energy Technologies, LLC and Robert Thorpe and John F. Charles, against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009. The defendants filed a motion to dismiss the case on August 25, 2011, with Atmos Energy filing a brief in response to such motion on September 19, 2011. On March 27, 2012 the court denied the motion to dismiss. Since that time, we have continued to be engaged in discovery activities in this case.
Tennessee Business License Tax
Atmos Energy, through its affiliate, AEM, has been involved in a dispute with the Tennessee Department of Revenue (TDOR) regarding sales business tax audits over a period of several years. AEM has challenged the assessment of the business tax. With respect to certain issues, AEM and the TDOR filed competing Partial Motions for Summary Judgment with the Chancery Court. On August 2, 2013, the Chancery Court granted the TDOR's Partial Motion for Summary Judgment and denied AEM's Partial Motion for Summary Judgment. The Company anticipates a decision by the Chancery Court on the remaining issues in fiscal 2014. AEM has been assessed $6.1 million in business taxes and $3.7 million in penalties and interest for the period from December 2002 through March 31, 2012. We believe the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.
We are a party to other litigation and environmental-related matters or claims that have arisen in the ordinary course of our business. While the results of such litigation and response actions to such environmental-related matters or claims cannot be predicted with certainty, we continue to believe the final outcome of such litigation and matters or claims will not have a material adverse effect on our financial condition, results of operations or cash flows.
Purchase Commitments
AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At June 30, 2013, AEH was committed to purchase 84.9 Bcf within one year, 45.1 Bcf within one to three years and 21.7 Bcf after three years under indexed contracts. AEH is committed to purchase 7.1 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.40 to $6.36 per Mcf. Purchases under these contracts totaled $340.9 million and $176.6 million for the three months ended June 30, 2013 and 2012 and $958.2 million and $753.0 million for the nine months ended June 30, 2013 and 2012.
Our natural gas distribution divisions, except for our Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of June 30, 2013 are as follows (in thousands):

2013	$32,791
2014	237,444
2015	—
2016	—
2017	—
Thereafter	—
	$270,235

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, 2012. There were no material changes to the estimated storage and transportation fees for the nine months ended June 30, 2013.

Regulatory Matters

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission (CFTC) to establish rules and regulations for implementation of many of the provisions of the Dodd-Frank Act. The costs of participating in financial markets for hedging certain risks inherent in our business have been increased as a result of the new legislation and related rules and regulations. We also are subject to additional recordkeeping and reporting obligations with regard to certain of our swap transactions. Although the CFTC and SEC have issued a number of required rules and regulations, we expect additional rules and regulations to be adopted, which should provide further clarity regarding the extent of the impact of this legislation on us.

As of June 30, 2013, rate cases were in progress in our Colorado and Kentucky service areas, an annual rate filing mechanism was in progress in Louisiana and an infrastructure program filing was in progress in Virginia. These regulatory proceedings are discussed in further detail below in Management's Discussion and Analysis — Recent Ratemaking Developments.

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, 2012. During the nine months ended June 30, 2013, there were no material changes in our concentration of credit risk.

12. Segment Information

As discussed in Note 1 above, we operate the Company through the following three segments:

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

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies found in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012. We evaluate performance based on net income or loss of the respective operating units.

Income statements for the three and nine month periods ended June 30, 2013 and 2012 by segment are presented in the following tables:

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

	Three Months Ended June 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$315,420	$26,551	$234,443	$—	$576,414
Intersegment revenues	214	40,522	21,807	(62,543)	—
	315,634	67,073	256,250	(62,543)	576,414
Purchased gas cost	120,575	—	224,829	(62,161)	283,243
Gross profit	195,059	67,073	31,421	(382)	293,171
Operating expenses					
Operation and maintenance	82,224	16,427	7,777	(383)	106,045
Depreciation and amortization	50,157	7,797	1,002	—	58,956
Taxes, other than income	42,011	3,839	774	—	46,624
Total operating expenses	174,392	28,063	9,553	(383)	211,625
Operating income	20,667	39,010	21,868	1	81,546
Miscellaneous income (expense)	(1,053)	(298)	136	(860)	(2,075)
Interest charges	27,820	7,353	595	(859)	34,909
Income (loss) from continuing operations before income taxes	(8,206)	31,359	21,409	—	44,562
Income tax expense (benefit)	(3,299)	11,215	8,632	—	16,548
Income (loss) from continuing operations	(4,907)	20,144	12,777	—	28,014
Income from discontinued operations, net of tax	3,118	—	—	—	3,118
Net income (loss)	$(1,789)	$20,144	$12,777	$—	$31,132
Capital expenditures	$149,531	$34,191	$2,529	$—	$186,251

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

	Nine Months Ended June 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
Operating revenues from external parties	$1,862,053	$66,421	$957,443	$—	$2,885,917
Intersegment revenues	761	115,448	113,746	(229,955)	—
	1,862,814	181,869	1,071,189	(229,955)	2,885,917
Purchased gas cost	1,011,832	—	1,028,592	(228,857)	1,811,567
Gross profit	850,982	181,869	42,597	(1,098)	1,074,350
Operating expenses					
Operation and maintenance	262,255	49,239	19,597	(1,102)	329,989
Depreciation and amortization	151,042	23,240	2,460	—	176,742
Taxes, other than income	130,232	11,538	2,400	—	144,170
Total operating expenses	543,529	84,017	24,457	(1,102)	650,901
Operating income	307,453	97,852	18,140	4	423,449
Miscellaneous income (expense)	(2,327)	(634)	739	(1,363)	(3,585)
Interest charges	84,775	22,176	1,686	(1,359)	107,278
Income from continuing operations before income taxes	220,351	75,042	17,193	—	312,586
Income tax expense	86,282	26,864	6,958	—	120,104
Income from continuing operations	134,069	48,178	10,235	—	192,482
Income from discontinued operations, net of tax	16,268	—	—	—	16,268
Net income	$150,337	$48,178	$10,235	$—	$208,750
Capital expenditures	$392,666	$97,182	$7,526	$—	$497,374

Balance sheet information at June 30, 2013 and September 30, 2012 by segment is presented in the following tables.

	June 30, 2013				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$4,646,302	$1,134,633	$60,280	$—	$5,841,215
Investment in subsidiaries	819,806	—	(2,096)	(817,710)	—
Current assets					
Cash and cash equivalents	5,870	—	26,109	—	31,979
Assets from risk management activities	2,015	—	11,996	—	14,011
Other current assets	413,030	15,941	503,007	(295,715)	636,263
Intercompany receivables	685,107	—	—	(685,107)	—
Total current assets	1,106,022	15,941	541,112	(980,822)	682,253
Intangible assets	—	—	131	—	131
Goodwill	573,550	132,422	34,711	—	740,683
Noncurrent assets from risk management activities	85,467	—	—	—	85,467
Deferred charges and other assets	426,179	18,380	8,490	—	453,049
	$7,657,326	$1,301,376	$642,628	$(1,798,532)	$7,802,798
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,581,444	$383,895	$435,911	$(819,806)	$2,581,444
Long-term debt	2,455,593	—	—	—	2,455,593
Total capitalization	5,037,037	383,895	435,911	(819,806)	5,037,037
Current liabilities					
Current maturities of long-term debt	—	—	—	—	—
Short-term debt	419,298	—	—	(277,300)	141,998
Liabilities from risk management activities	1,094	—	3	—	1,097
Other current liabilities	446,483	9,983	137,338	(16,319)	577,485
Intercompany payables	—	627,933	57,174	(685,107)	—
Total current liabilities	866,875	637,916	194,515	(978,726)	720,580
Deferred income taxes	909,925	278,898	8,451	—	1,197,274
Noncurrent liabilities from risk management activities	—	—	2,064	—	2,064
Regulatory cost of removal obligation	360,578	—	—	—	360,578
Deferred credits and other liabilities	482,911	667	1,687	—	485,265
	$7,657,326	$1,301,376	$642,628	$(1,798,532)	$7,802,798

32

	September 30, 2012				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Property, plant and equipment, net	$4,432,017	$979,443	$64,144	$—	$5,475,604
Investment in subsidiaries	747,496	—	(2,096)	(745,400)	—
Current assets					
Cash and cash equivalents	12,787	—	51,452	—	64,239
Assets from risk management activities	6,934	—	17,773	—	24,707
Other current assets	546,187	11,788	404,097	(223,056)	739,016
Intercompany receivables	636,557	—	—	(636,557)	—
Total current assets	1,202,465	11,788	473,322	(859,613)	827,962
Intangible assets	—	—	164	—	164
Goodwill	573,550	132,422	34,711	—	740,683
Noncurrent assets from risk management activities	2,283	—	—	—	2,283
Deferred charges and other assets	417,893	24,353	6,733	—	448,979
	$7,375,704	$1,148,006	$576,978	$(1,605,013)	$7,495,675
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,359,243	$328,161	$419,335	$(747,496)	$2,359,243
Long-term debt	1,956,305	—	—	—	1,956,305
Total capitalization	4,315,548	328,161	419,335	(747,496)	4,315,548
Current liabilities					
Current maturities of long-term debt	—	—	131	—	131
Short-term debt	782,719	—	—	(211,790)	570,929
Liabilities from risk management activities	85,366	—	15	—	85,381
Other current liabilities	526,089	12,478	90,116	(9,170)	619,513
Intercompany payables	—	584,578	51,979	(636,557)	—
Total current liabilities	1,394,174	597,056	142,241	(857,517)	1,275,954
Deferred income taxes	789,288	220,647	5,148	—	1,015,083
Noncurrent liabilities from risk management activities	—	—	9,206	—	9,206
Regulatory cost of removal obligation	381,164	—	—	—	381,164
Deferred credits and other liabilities	495,530	2,142	1,048	—	498,720
	$7,375,704	$1,148,006	$576,978	$(1,605,013)	$7,495,675

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, 2013, the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended June 30, 2013 and 2012, and the condensed consolidated statements of cash flows for the nine-month periods ended June 30, 2013 and 2012. These financial statements are the responsibility of the Company's management.

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

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

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Atmos Energy Corporation and subsidiaries as of September 30, 2012, and the related consolidated statements of income, shareholders' equity, and cash flows for the year then ended, not presented herein, and in our report dated November 12, 2012, 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, 2012, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ ERNST & YOUNG LLP
Dallas, Texas
August 7, 2013

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, 2012.

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

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

OVERVIEW

Atmos Energy and our subsidiaries are engaged primarily in the regulated natural gas distribution and transportation and storage businesses as well as other nonregulated natural gas businesses. We distribute natural gas through sales and transportation arrangements to approximately three million residential, commercial, public authority and industrial customers throughout our six regulated natural gas distribution divisions, which at June 30, 2013 covered service areas located in eight states. In addition, we transport natural gas for others through our regulated distribution and pipeline systems. On April 1, 2013, we completed the divestiture of our natural gas distribution operations in Georgia, representing approximately 64,000 customers.

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

As discussed in Note 12, we operate the Company through the following three segments:

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

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

Our condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities.

We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results may differ from such estimates.

Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K for the fiscal year ended September 30, 2012 and include the following:

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

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, 2013.

RESULTS OF OPERATIONS

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. Historically, this generally has resulted in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 56 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

However, we anticipate that rate design changes, implemented upon the completion of our most recent rate cases in our Mid-Tex and West Texas Divisions during the first quarter of fiscal 2013, will change this trend. The rate design approved in these regulatory proceedings includes an increase to the customer base charge and a decrease in the consumption charge applied to customer usage. The effect of this change in rate design allows our rates to be more closely aligned with the natural gas distribution industry standard rate design. In addition, we anticipate these divisions, which represent approximately 50 percent of the operating income for our natural gas distribution segment, will earn their operating income more ratably over the fiscal year as we are now less dependent on customer consumption. Thus, as expected, we experienced a decline in operating income during the first six months of fiscal 2013 when these rates were implemented. However, the decline experienced during the first six months was partially offset by higher operating income in the third fiscal quarter.

Additionally, the seasonality of our business impacts our working capital differently at various times during the year. Typically, our accounts receivable, accounts payable and short-term debt balances peak by the end of January and then start to decline, as customers begin to pay their winter heating bills. Gas stored underground, particularly in our natural gas distribution segment, typically peaks in November and declines as we utilize storage gas to serve our customers.

We reported net income of $38.8 million, or $0.42 per diluted share for the three months ended June 30, 2013 compared with net income of $31.1 million, or $0.34 per diluted share in the prior-year quarter. Excluding the impact of unrealized margins, diluted earnings per share increased $0.16 compared with the prior-year quarter. During the nine months ended June 30, 2013 we earned $235.7 million or $2.57 per diluted share, compared with $208.8 million, or $2.28 per diluted share in the prior-year period. Excluding the impact of unrealized margins, diluted earnings per share increased $0.26 compared with the prior-year period. The quarter-over-quarter increase in net income, excluding unrealized margins, was primarily due to the aforementioned rate design changes in our natural gas distribution Texas service areas combined with increased consumption during the fiscal third quarter. The period-over-period increase reflects higher gross profit attributable to current year rate increases in our Kentucky/Mid-States, Colorado-Kansas, Mississippi and Louisiana divisions, recent rate increases approved in our regulated transmission and storage segment and improved asset optimization margins in our nonregulated segment, coupled with lower interest expense.

We completed the sale of our Georgia natural gas distribution operations on April 1, 2013 to Liberty Energy (Georgia) Corp., an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $153 million. The proposed sale was previously announced on August 8, 2012. In connection with the sale, we recognized a net of tax gain of $5.3 million. Accordingly, the results of operations for this service area are shown in discontinued operations for both periods presented. Prior-year results also reflect our Illinois, Iowa and Missouri service areas in discontinued operations. The sale of these three service areas was completed in August 2012. During the nine months ended June 30, 2013, net income from discontinued operations was $12.5 million, or $0.14 per diluted share and includes the $5.3 million gain on sale of substantially all of our assets in Georgia. Net income from discontinued operations was $16.3 million, or $0.18 per diluted share in the prior-year period.

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

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

Consolidated Results

The following table presents our consolidated financial highlights for the three and nine months ended June 30, 2013 and 2012:

	Three Months Ended June 30		Nine Months Ended June 30	
	2013	2012	2013	2012
	(In thousands, except per share data)			
Operating revenues	$857,935	$576,414	$3,201,086	$2,885,917
Gross profit	316,497	293,171	1,111,610	1,074,350
Operating expenses	230,101	211,625	660,114	650,901
Operating income	86,396	81,546	451,496	423,449
Miscellaneous income (expense)	(467)	(2,075)	1,943	(3,585)
Interest charges	32,741	34,909	96,594	107,278
Income from continuing operations before income taxes	53,188	44,562	356,845	312,586
Income tax expense	19,714	16,548	133,683	120,104
Income from continuing operations	33,474	28,014	223,162	192,482
Income from discontinued operations, net of tax	—	3,118	7,202	16,268
Gain on sale of discontinued operations, net of tax	5,294	—	5,294	—
Net income	$38,768	$31,132	$235,658	$208,750
Diluted net income per share from continuing operations	$0.36	$0.31	$2.43	$2.10
Diluted net income per share from discontinued operations	0.06	0.03	0.14	0.18
Diluted net income per share	$0.42	$0.34	$2.57	$2.28

Our consolidated net income (loss) during the three and nine month periods ended June 30, 2013 and 2012 was earned in each of our business segments as follows:

	Three Months Ended June 30		
	2013	2012	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$15,817	$(4,907)	$20,724
Regulated transmission and storage segment	23,097	20,144	2,953
Nonregulated segment	(5,440)	12,777	(18,217)
Net income from continuing operations	33,474	28,014	5,460

Net income from discontinued operations	5,294	3,118	2,176
Net income	$38,768	$31,132	$7,636

	Nine Months Ended June 30		
	2013	2012	Change
	(In thousands)		
Natural gas distribution segment from continuing operations	$155,100	$134,069	$21,031
Regulated transmission and storage segment	55,732	48,178	7,554
Nonregulated segment	12,330	10,235	2,095
Net income from continuing operations	223,162	192,482	30,680
Net income from discontinued operations	12,496	16,268	(3,772)
Net income	$235,658	$208,750	$26,908

Regulated operations contributed 94 percent to our consolidated net income from continuing operations for the nine months ended June 30, 2013. The following tables reflect the segregation of our consolidated net income (loss) and diluted earnings per share between our regulated and nonregulated operations:

	Three Months Ended June 30		
	2013	2012	Change
	(In thousands, except per share data)		
Regulated operations	$38,914	$15,237	$23,677
Nonregulated operations	(5,440)	12,777	(18,217)
Net income from continuing operations	33,474	28,014	5,460
Net income from discontinued operations	5,294	3,118	2,176
Net income	$38,768	$31,132	$7,636
Diluted EPS from continuing regulated operations	$0.42	$0.17	$0.25
Diluted EPS from nonregulated operations	(0.06)	0.14	(0.20)
Diluted EPS from continuing operations	0.36	0.31	0.05
Diluted EPS from discontinued operations	0.06	0.03	0.03
Consolidated diluted EPS	$0.42	$0.34	$0.08

	Nine Months Ended June 30		
	2013	2012	Change
	(In thousands, except per share data)		
Regulated operations	$210,832	182,247	$28,585
Nonregulated operations	12,330	10,235	2,095
Net income from continuing operations	223,162	192,482	30,680
Net income from discontinued operations	12,496	16,268	(3,772)
Net income	$235,658	$208,750	$26,908
Diluted EPS from continuing regulated operations	$2.30	$1.99	$0.31
Diluted EPS from nonregulated operations	0.13	0.11	0.02
Diluted EPS from continuing operations	2.43	2.10	0.33
Diluted EPS from discontinued operations	0.14	0.18	(0.04)
Consolidated diluted EPS	$2.57	$2.28	$0.29

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

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

38

Seasonal weather patterns can also affect our natural gas distribution operations. However, the effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which has been approved by state regulatory commissions for approximately 96 percent of our residential and commercial meters in the following states for the following time periods:

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

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

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

As discussed above, on April 1, 2013, we completed the sale of substantially all of our natural gas distribution operations in Georgia. Prior-year results also reflect our Illinois, Iowa and Missouri service areas in discontinued operations. The results of these operations have been separately reported in the following tables as discontinued operations and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

During the first nine months of fiscal 2013, we completed 12 regulatory proceedings, which should result in a $70.5 million increase in annual operating income. The majority of this rate increase related to our Mid-Tex Division, where rates became effective January 1, 2013. The rate design approved in our Mid-Tex Division and West Texas Division regulatory proceedings includes an increase to the base customer charge and a decrease in the commodity charge applied to customer consumption. The effect of this change in rate design allows the Company’s rates to be more closely aligned with utility industry standard rate design. In addition, we anticipate these divisions will earn their operating income more ratably over the fiscal year as we are now less dependent on customer consumption. Therefore, we anticipate operating income earned during the first and second fiscal quarters to be lower than in previous periods while operating income earned during the third and fourth fiscal quarters to be higher than in previous periods. For fiscal 2013, as expected, we experienced a decline in operating income in the first and second fiscal quarters when these rates became effective. However, this decline was partially offset in the third fiscal quarter with higher operating income compared to the prior-year period.

Three Months Ended June 30, 2013 compared with Three Months Ended June 30, 2012

Financial and operational highlights for our natural gas distribution segment for the three months ended June 30, 2013 and 2012 are presented below.

	Three Months Ended June 30		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Gross profit	$239,495	$195,059	$44,436
Operating expenses	187,544	174,392	13,152
Operating income	51,951	20,667	31,284
Miscellaneous income (expense)	268	(1,053)	1,321
Interest charges	25,001	27,820	(2,819)
Income (loss) from continuing operations before income taxes	27,218	(8,206)	35,424
Income tax expense (benefit)	11,401	(3,299)	14,700
Income (loss) from continuing operations	15,817	(4,907)	20,724
Income from discontinued operations, net of tax	—	3,118	(3,118)
Gain on sale of discontinued operations, net of tax	5,649	—	5,649
Net income (loss)	$21,466	$(1,789)	$23,255
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	43,190	32,535	10,655
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	29,179	29,856	(677)
Consolidated natural gas distribution throughput from continuing operations — MMcf	72,369	62,391	9,978
Consolidated natural gas distribution throughput from discontinued operations — MMcf	—	3,309	(3,309)
Total consolidated natural gas distribution throughput — MMcf	72,369	65,700	6,669
Consolidated natural gas distribution average transportation revenue per Mcf	$0.45	$0.43	$0.02
Consolidated natural gas distribution average cost of gas per Mcf sold	$5.27	$3.73	$1.54

The $44.4 million quarter-over-quarter increase in natural gas distribution gross profit primarily reflects the following:

- $28.6 million increase from rate design changes and rate increases, primarily in the Mid-Tex and West Texas Divisions.
- $10.5 million increase due to colder weather experienced across most of our service territories after the weather normalization adjustment period.

The increase in gross profit was partially offset by a $13.2 million increase in operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income, primarily due to the following:

- $4.8 million increase in labor costs primarily due to less labor capitalized in the current year.
- $2.3 million increase in bad debt expense primarily attributable to an increase in revenue arising from the rate design changes and the temporary suspension of active customer collection activities following the implementation of a new customer information system during the current quarter.
- $2.6 million increase in pension and postretirement benefit costs.
- $1.8 million increase primarily associated with higher line locate activities, pipeline and right-of-way maintenance activities.

Miscellaneous income increased $1.3 million, primarily due to higher income earned from performance-based rate (PBR) mechanisms in our Tennessee service area and the implementation of a new PBR in our Mississippi Division.

Interest charges decreased $2.8 million, primarily from interest deferrals associated with our infrastructure spending activities in Texas.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the three months ended June 30, 2013 and 2012. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Three Months Ended June 30		
	2013	2012	Change
	(In thousands)		
Mid-Tex	$30,457	$5,845	$24,612
Kentucky/Mid-States	5,498	1,946	3,552
Louisiana	7,543	6,880	663
West Texas	3,678	353	3,325
Mississippi	1,634	1,785	(151)
Colorado-Kansas	2,076	1,466	610
Other	1,065	2,392	(1,327)
Total	$51,951	$20,667	$31,284

Nine Months Ended June 30, 2013 compared with Nine Months Ended June 30, 2012

Financial and operational highlights for our natural gas distribution segment for the nine months ended June 30, 2013 and 2012 are presented below.

	Nine Months Ended June 30		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Gross profit	$866,132	$850,982	$15,150
Operating expenses	544,658	543,529	1,129
Operating income	321,474	307,453	14,021
Miscellaneous income (expense)	2,728	(2,327)	5,055
Interest charges	74,228	84,775	(10,547)
Income from continuing operations before income taxes	249,974	220,351	29,623
Income tax expense	94,874	86,282	8,592
Income from continuing operations	155,100	134,069	21,031
Income from discontinued operations, net of tax	7,202	16,268	(9,066)
Gain on sale of discontinued operations, net of tax	5,649	—	5,649
Net income	$167,951	$150,337	$17,614
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	242,066	217,322	24,744
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	98,608	98,374	234
Consolidated natural gas distribution throughput from continuing operations — MMcf	340,674	315,696	24,978
Consolidated natural gas distribution throughput from discontinued operations — MMcf	4,731	16,646	(11,915)
Total consolidated natural gas distribution throughput — MMcf	345,405	332,342	13,063
Consolidated natural gas distribution average transportation revenue per Mcf	$0.45	$0.44	$0.01
Consolidated natural gas distribution average cost of gas per Mcf sold	$4.86	$4.70	$0.16

The $15.2 million period-over-period increase in natural gas distribution gross profit primarily reflects the following:

- $12.5 million increase in rates in our Kentucky/Mid-States, Colorado-Kansas, Mississippi and Louisiana divisions.
- $7.4 million increase due to colder weather, primarily in the Mississippi, Kentucky/Mid-States and Colorado-Kansas divisions.

- $4.0 million increase in transportation revenues.

41

These increases were partially offset by a $9.0 million decrease associated with the rate design changes implemented in the Mid-Tex and West Texas divisions in the fiscal first quarter.

The increases in gross profit were partially offset by a $1.1 million increase in operating expenses, primarily due to the following:

- $6.6 million increase primarily associated with higher line locate activities, pipeline and right-of-way maintenance activities.
- $4.3 million increase in labor costs primarily due to less labor capitalized in the current year.
- $2.1 million increase in bad debt expense primarily attributable to an increase in revenue arising from the rate design changes and the temporary suspension of active customer collection activities following the implementation of a new customer information system during the current quarter.
- $1.8 million increase in pension and postretirement benefit costs.

These increases were partially offset by:

- $5.6 million decrease in legal and other administrative costs.
- $5.0 million decrease in depreciation expense due to new depreciation rates approved in the most recent Mid-Tex rate case that went into effect in January 2013.
- $2.4 million gain realized on the sale of certain investments.

Miscellaneous income increased $5.1 million, primarily due to due to the completion of a periodic review of our PBR mechanism in our Tennessee service area and the implementation of a new PBR program in our Mississippi Division.

Interest charges decreased $10.5 million, primarily from interest deferrals associated with our infrastructure spending activities in Texas.

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the nine months ended June 30, 2013 and 2012. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	Nine Months Ended June 30		
	2013	2012	Change
	(In thousands)		
Mid-Tex	$135,747	$142,595	$(6,848)
Kentucky/Mid-States	45,700	32,053	13,647
Louisiana	48,432	44,551	3,881
West Texas	28,264	29,017	(753)
Mississippi	33,072	29,454	3,618
Colorado-Kansas	27,497	23,627	3,870
Other	2,762	6,156	(3,394)
Total	$321,474	$307,453	$14,021

Recent Ratemaking Developments

Significant ratemaking developments that occurred during the nine months ended June 30, 2013 are discussed below. The amounts described below 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.

Annual net operating income increases totaling $70.5 million resulting from ratemaking activity became effective in the nine months ended June 30, 2013 as summarized below:

Rate Action	Annual Increase to Operating Income
	(In thousands)
Rate case filings	$56,700
Infrastructure programs	4,206
Annual rate filing mechanisms	8,244
Other rate activity	1,322
	$70,472

Additionally, the following ratemaking efforts were in progress during the third quarter of fiscal 2013 but had not been completed as of June 30, 2013.

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Colorado-Kansas	Rate Case(1)	Colorado	$10,891
Kentucky/Mid-States	Rate Case	Kentucky	13,133
Kentucky/Mid-States	Infrastructure Replacement	Virginia	213
Louisiana	Rate Stabilization Clause (2)	LGS	1,570
			$25,807

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

(2) In June 2013, the Company accepted the Staff's recommended adjustments and implemented an annual increase to operating income of $0.9 million effective in rates on July 1, 2013.

On July 15, 2013, the Company filed a rate review mechanism (RRM) in our Mid-Tex Division, requesting a net increase in annual operating income of $17.1 million.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to our customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a “show cause” action. Adequate rates are intended to provide for recovery of the Company’s costs as well as a fair rate of return to our shareholders and ensure that we continue to deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes the rate cases that were completed during the nine months ended June 30, 2013.

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

Infrastructure Programs

Infrastructure programs such as the Gas Reliability Infrastructure Program (GRIP) allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. As of June 30, 2013, we had infrastructure programs approved in Texas, Kansas, Colorado, Kentucky and Virginia. The following table summarizes our infrastructure program filings with effective dates occurring during the nine months ended June 30, 2013.

Division	Period End	Incremental Net Utility Plant Investment (In thousands)	Increase in Annual Operating Income (In thousands)	Effective Date
2013 Infrastructure Programs:				
Colorado-Kansas — Kansas	09/2012	$5,376	$601	01/09/2013
Kentucky/Mid-States — Georgia[1]	09/2011	6,519	1,079	10/01/2012
Kentucky/Mid-States — Kentucky	09/2013	19,296	2,425	10/01/2012
Kentucky/Mid-States — Virginia	09/2013	756	101	10/01/2012
Total 2013 Infrastructure Programs		$31,947	$4,206	

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

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. As of June 30, 2013 we had annual rate filing mechanisms in our Louisiana and Mississippi service areas and in a majority of the service areas in our Mid-Tex Division. These mechanisms are referred to as the Dallas annual rate review (DARR) and rate review mechanism (RRM) in our Mid-Tex Division, stable rate filings in the Mississippi Division and a rate stabilization clause in the Louisiana Division. Discussions are underway regarding a new rate review mechanism processes in our West Texas Division, as was contemplated by the parties in the settlement of the fiscal 2012 rate case. The following annual rate filing mechanisms were completed during the nine months ended June 30, 2013.

Division	Jurisdiction	Test Year Ended	Additional Annual Operating Income	Effective Date
		(In thousands)		
2013 Filings:				
Mid-Tex	City of Dallas	9/30/2012	$1,800	06/01/2013
Louisiana	TransLa	9/30/2012	2,260	04/01/2013
Kentucky/Mid-States	Georgia[1]	9/30/2013	743	02/01/2013
Mississippi	Mississippi	6/30/2012	3,441	11/01/2012
Total 2013 Filings			$8,244	

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

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the nine months ended June 30, 2013:

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

Total 2013 Other Rate Activity	$1,322

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline–Texas Division. The Atmos Pipeline–Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending arrangements and sales of excess gas.

Our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex service area. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our Mid-Tex Division.

Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Three Months Ended June 30, 2013 compared with Three Months Ended June 30, 2012

Financial and operational highlights for our regulated transmission and storage segment for the three months ended June 30, 2013 and 2012 are presented below.

	Three Months Ended June 30		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$47,117	$43,693	$3,424
Third-party transportation	18,122	17,281	841
Storage and park and lend services	1,412	1,484	(72)
Other	7,390	4,615	2,775
Gross profit	74,041	67,073	6,968
Operating expenses	29,998	28,063	1,935
Operating income	44,043	39,010	5,033
Miscellaneous expense	(247)	(298)	51
Interest charges	8,049	7,353	696
Income before income taxes	35,747	31,359	4,388
Income tax expense	12,650	11,215	1,435
Net income	$23,097	$20,144	$2,953
Gross pipeline transportation volumes — MMcf	153,216	146,170	7,046
Consolidated pipeline transportation volumes — MMcf	121,194	118,678	2,516

The $7.0 million increase in regulated transmission and storage gross profit compared to the prior-year quarter was primarily a result of the GRIP filing approved by the RRC during fiscal 2013. On May 7, 2013, the RRC approved the Atmos Pipeline - Texas (APT) GRIP filing with an annual operating income increase of $26.7 million that went into effect with bills rendered on and after May 7, 2013. GRIP filings increased quarter-over-quarter gross profit by $5.6 million.

On June 30, 2013, APT's annual adjustment mechanism expired. The three-year pilot program, approved in fiscal 2011, annually adjusted regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit. During the fourth quarter of fiscal 2013, APT will request an extension of the annual adjustment mechanism through November 2017.

Operating expenses increased $1.9 million primarily due to increased pipeline maintenance and right-of-way activities.

45

Nine Months Ended June 30, 2013 compared with Nine Months Ended June 30, 2012
Financial and operational highlights for our regulated transmission and storage segment for the nine months ended June 30, 2013 and 2012 are presented below.

	Nine Months Ended June 30		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Mid-Tex transportation	$130,849	$120,150	$10,699
Third-party transportation	47,440	46,529	911
Storage and park and lend services	4,484	5,157	(673)
Other	13,797	10,033	3,764
Gross profit	196,570	181,869	14,701
Operating expenses	87,014	84,017	2,997
Operating income	109,556	97,852	11,704
Miscellaneous expense	(473)	(634)	161
Interest charges	22,777	22,176	601
Income before income taxes	86,306	75,042	11,264
Income tax expense	30,574	26,864	3,710
Net income	$55,732	$48,178	$7,554
Gross pipeline transportation volumes — MMcf	493,721	483,360	10,361
Consolidated pipeline transportation volumes — MMcf	335,036	333,341	1,695

The $14.7 million increase in regulated transmission and storage gross profit compared to the prior-year period was primarily a result of the GRIP filings approved by the RRC during fiscal 2012 and 2013. During fiscal 2012, the Commission approved the Atmos Pipeline - Texas GRIP filing with an annual operating income increase of $14.7 million, effective April 2012. On May 7, 2013, the RRC approved the Atmos Pipeline - Texas GRIP filing with an annual operating income increase of $26.7 million that went into effect with bills rendered on and after May 7, 2013. GRIP filings increased period-over-period gross profit by $13.0 million.

This increase was partially offset by a $3.0 million increase in operating expenses largely attributable to increased depreciation expense as a result of increased capital investments and increased pipeline maintenance and right-of-way activities.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH’s primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. These activities are reflected as gas delivery and related services in the table below.

AEH also earns storage and transportation margins from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods. Most of these margins are generated through demand fees established under contracts with certain of our natural gas distribution divisions that are renewed periodically and subject to regulatory oversight. These activities are reflected as storage and transportation services in the table below.

AEH utilizes customer-owned or contracted storage capacity to serve its customers. AEH seeks to offset the demand fees paid to contract for storage capacity and to maximize the value of this capacity by selling financial instruments to earn a gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. Margins earned from these activities and the related storage demand fees are reported as asset optimization margins. Certain of these arrangements are with regulated affiliates, which have been approved by applicable state regulatory commissions.

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 gas and demand fees paid to contract for storage capacity to offer more competitive pricing to those customers.

Further, natural gas market conditions, most notably the price of natural gas and the level of price volatility affect our nonregulated businesses. Natural gas prices and the level of volatility are influenced by a number of factors including, but not limited to, general economic conditions, the demand for natural gas in different parts of the country, the level of domestic natural gas production and the level of natural gas inventory levels.

Natural gas prices can influence:

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

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

- Price volatility influences basis differentials, which provide opportunities to profit from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access.
- Price volatility also influences the spreads between the current (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads.
- Increased 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.

Although natural gas prices have risen somewhat during the last 12 months, the natural gas marketing industry continues to experience compressed basis differentials and lower spot-to-forward price volatility. Accordingly, while we anticipate continuing to profit on a fiscal year basis from our nonregulated activities, we anticipate this segment will continue to represent less than ten percent of our consolidated results.

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. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will generally record unrealized losses or lower unrealized gains. 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, 2013 compared with Three Months Ended June 30, 2012

Financial and operating highlights for our nonregulated segment for the three months ended June 30, 2013 and 2012 are presented below.

	Three Months Ended June 30		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$5,945	$9,637	$(3,692)
Storage and transportation services	3,689	3,313	376
Other	846	791	55
	10,480	13,741	(3,261)
Asset optimization[1]	2,476	14,600	(12,124)
Total realized margins	12,956	28,341	(15,385)
Unrealized margins	(9,696)	3,080	(12,776)
Gross profit	3,260	31,421	(28,161)
Operating expenses	12,860	9,553	3,307
Operating income (loss)	(9,600)	21,868	(31,468)
Miscellaneous income	215	136	79
Interest charges	392	595	(203)
Income (loss) from continuing operations before income taxes	(9,777)	21,409	(31,186)
Income tax expense (benefit)	(4,337)	8,632	(12,969)
Income (loss) from continuing operations	(5,440)	12,777	(18,217)
Loss on sale of discontinued operations, net of tax	(355)	—	(355)
Net income (loss)	$(5,795)	$12,777	$(18,572)
Gross nonregulated delivered gas sales volumes — MMcf	97,388	89,682	7,706
Consolidated nonregulated delivered gas sales volumes — MMcf	83,341	79,658	3,683
Net physical position (Bcf)	19.2	30.3	(11.1)

(1) Net of storage fees of $2.3 million and $4.2 million.

Gross profit decreased $28.2 million compared to the prior-year quarter, primarily as a result of a $15.4 million decrease in realized margins and a $12.8 million decrease in unrealized margins. The decrease in realized margins primarily reflects decreased asset optimization margins primarily due to the timing and magnitude of gains realized on the settlement of financial positions in the prior-year quarter. During the first six months of fiscal 2012, Atmos Energy Holdings took advantage of falling natural gas prices by injecting gas into storage and rolling financial positions forward for settlement in the third and fourth quarters of fiscal 2012. The spreads captured as a result of this activity were higher than the spreads captured from current period asset optimization activities. This decrease was partially offset by a $1.9 million decrease in storage fees as non-essential contracts were not renewed and expiring contracts were renewed at lower rates reflecting the current market for storage.

Realized margins for gas delivery and related services decreased $3.7 million primarily due to a decrease in gas delivery per-unit margins from 11 cents per Mcf in the prior-year quarter to 6 cents per Mcf, partially offset by a five percent increase in consolidated sales volumes. The decrease in per-unit margins reflects increased sales to lower margin customers, primarily asset management customers, where the lower delivered margins are recovered through asset optimization services. These increased sales contributed to our overall increase in consolidated sales volumes.

Unrealized margins decreased $12.8 million.

Operating expenses increased $3.3 million, primarily due to litigation related expenses.

Nine Months Ended June 30, 2013 compared with Nine Months Ended June 30, 2012

Financial and operational highlights for our nonregulated segment for the nine months ended June 30, 2013 and 2012 are presented below.

	Nine Months Ended June 30		
	2013	2012	Change
	(In thousands, unless otherwise noted)		
Realized margins			
Gas delivery and related services	$31,279	$35,021	$(3,742)
Storage and transportation services	10,806	9,953	853
Other	2,643	2,804	(161)
	44,728	47,778	(3,050)
Asset optimization[1]	(10,625)	(17,039)	6,414
Total realized margins	34,103	30,739	3,364
Unrealized margins			