Form

```
Unknown document format
```

left:2px;padding-top:2px;padding-bottom:2px;padding-right:2px;">

11.8

Inventories

332.0

365.5

304.0

Deferred income taxes

9.1

10.6

6.6

Utility regulatory assets

9.4

8.2

3.7

Derivative financial instruments

12.4

23.8

18.7

Prepaid expenses and other current assets

38.3

57.1

36.1

Total current assets

1,638.9

1,627.3

1,541.3

Property, plant and equipment, at cost (less accumulated depreciation and amortization of $2,702.3, $2,560.3 and $2,495.4, respectively)

4,543.4

4,480.2

4,323.7

Goodwill

2,885.1

2,871.0

2,834.0

Intangible assets, net

590.3

610.6

608.6

Other assets

420.0

419.7

499.2

Total assets

$
10,077.7

$
10,008.8

$
9,806.8

LIABILITIES AND EQUITY

Current liabilities:

Current maturities of long-term debt

$
78.4

$
67.2

$
195.6

Bank loans

96.5

227.9

135.9

Accounts payable

403.8

472.3

384.5

Derivative financial instruments

26.2

30.0

56.8

Other current liabilities

609.3

627.5

552.9

Total current liabilities

1,214.2

1,424.9

1,325.7

Long-term debt

3,477.8

3,542.2

3,298.2

Deferred income taxes

986.2

962.3

933.5

Deferred investment tax credits

4.0

4.3

4.4

Other noncurrent liabilities

514.7

527.2

616.9

Total liabilities

6,196.9

6,460.9

6,178.7

Commitments and contingencies (Note 10)

Equity:

UGI Corporation stockholders' equity:

UGI Common Stock, without par value (authorized—300,000,000 shares; issued — 115,830,694, 115,783,794 and 115,759,694 shares, respectively)

1,216.0

1,208.1

1,192.9

Retained earnings

1,566.7

1,308.3

1,354.9

Accumulated other comprehensive income (loss)

25.4

8.4

(27.4
)
Treasury stock, at cost

(37.1
)

(32.3
)

(26.2
)
Total UGI Corporation stockholders’ equity

2,771.0

2,492.5

2,494.2

Noncontrolling interests, principally in AmeriGas Partners

1,109.8

1,055.4

1,133.9

Total equity

3,880.8

3,547.9

3,628.1

Total liabilities and equity

$
10,077.7

$
10,008.8

$
9,806.8

See accompanying notes to condensed consolidated financial statements.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)
(Millions of dollars, except per share amounts)

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2014	2013 (Revised, See Note 3)	2014	2013 (Revised, See Note 3)
Revenues	$1,486.7	$1,374.3	$6,965.9	$5,935.7
Costs and expenses:				
Cost of sales (excluding depreciation shown below)	926.5	836.8	4,357.7	3,539.0
Operating and administrative expenses	415.9	407.5	1,339.4	1,295.9
Utility taxes other than income taxes	3.7	3.7	12.7	12.7
Depreciation	74.6	76.4	230.0	222.9
Amortization	15.4	15.4	41.7	46.3
Other income, net	(12.1)	(7.0)	(30.6)	(24.5)
	1,424.0	1,332.8	5,950.9	5,092.3
Operating income	62.7	41.5	1,015.0	843.4
(Loss) income from equity investees	(0.1)	—	(0.1)	0.1
Interest expense	(60.1)	(59.2)	(178.9)	(180.8)
Income (loss) before income taxes	2.5	(17.7)	836.0	662.7
Income tax expense	(15.2)	(5.1)	(243.4)	(176.0)
Net (loss) income	(12.7)	(22.8)	592.6	486.7
Add net loss (deduct net income) attributable to noncontrolling interests, principally in AmeriGas Partners	33.3	31.9	(235.6)	(194.4)
Net income attributable to UGI Corporation	$20.6	$9.1	$357.0	$292.3
Earnings per common share attributable to UGI Corporation stockholders:				
Basic	$0.18	$0.08	$3.10	$2.57
Diluted	$0.18	$0.08	$3.06	$2.54
Average common shares outstanding (thousands):				
Basic	115,370	114,240	115,121	113,693
Diluted	117,048	116,196	116,731	115,275
Dividends declared per common share	$0.2950	$0.2825	$0.8600	$0.8225

See accompanying notes to condensed consolidated financial statements.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(unaudited)
(Millions of dollars)

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2014	2013 (Revised, See Note 3)	2014	2013 (Revised, See Note 3)
Net (loss) income	$(12.7)	$(22.8)	$592.6	$486.7
Other comprehensive income (loss):				
Net (losses) gains on derivative instruments (net of tax of $0.6, $(4.1) $(6.5) and $(7.1), respectively)	(0.6)	(7.6)	46.2	(7.2)
Reclassifications of net (gains) losses on derivative instruments (net of tax of $(1.3), $(2.1), $4.0 and $(9.8), respectively)	(1.5)	9.7	(46.7)	52.3
Foreign currency adjustments (net of tax of $0.0, $(2.4), $(3.1) and $1.8, respectively)	(0.2)	8.8	11.5	1.3
Benefit plans (net of tax of $(0.2), $(0.2), $(0.2) and $(0.7), respectively)	0.2	0.3	0.8	1.1
Other comprehensive (loss) income	(2.1)	11.2	11.8	47.5
Comprehensive (loss) income	(14.8)	(11.6)	604.4	534.2
Add comprehensive loss (deduct comprehensive income) attributable to noncontrolling interests, principally in AmeriGas Partners	36.5	39.9	(230.4)	(214.0)
Comprehensive income attributable to UGI Corporation	$21.7	$28.3	$374.0	$320.2

See accompanying notes to condensed consolidated financial statements.

Table of Contents

UGI CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)
(Millions of dollars)

	Nine Months Ended June 30, 2014	2013 (Revised, See Note 3)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$592.6	$486.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	271.7	269.2
Deferred income taxes, net	21.2	32.2
Provision for uncollectible accounts	38.2	23.9
Unrealized losses (gains) on derivative instruments	3.1	(0.7)
Other, net	(4.9)	(3.6)
Net change in:		
Accounts receivable and accrued utility revenues	(56.4)	(146.2)
Inventories	34.8	51.3
Utility deferred fuel and power costs, net of changes in unsettled derivatives	(17.6)	20.5
Accounts payable	(40.8)	(25.5)
Other current assets	11.2	52.4
Other current liabilities	5.0	(73.8)
Net cash provided by operating activities	858.1	686.4
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(325.5)	(291.6)
Acquisitions of businesses, net of cash acquired	(23.3)	(24.3)
Decrease (increase) in restricted cash	2.4	(3.0)
Other, net	9.0	2.2
Net cash used by investing activities	(337.4)	(316.7)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(98.6)	(93.4)
Distributions on AmeriGas Partners publicly held Common Units	(176.9)	(168.5)
Issuances of debt	175.0	—
Repayments of debt	(236.8)	(28.5)
Decrease in bank loans	(74.6)	(39.0)
Receivables Facility net (repayments) borrowings	(57.0)	9.5
Issuances of UGI Common Stock	7.0	28.5
Repurchases of UGI Common Stock	(21.4)	—
Other	7.9	5.4
Net cash used by financing activities	(475.4)	(286.0)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	3.8	(1.8)
Cash and cash equivalents increase	$49.1	$81.9
Cash and cash equivalents:		
End of period	$438.4	$401.8
Beginning of period	389.3	319.9
Increase	$49.1	$81.9

See accompanying notes to condensed consolidated financial statements.

- 4 -

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(unaudited)
(Millions of dollars)

	Nine Months Ended June 30,	
	2014	2013 (Revised, See Note 3)
Common stock, without par value		
Balance, beginning of period	$ 1,208.1	$ 1,157.7
Common Stock issued in connection with employee and director plans (including gains (losses) on treasury stock transactions), net of tax withheld	(9.6)	19.7
Dividend reinvestment plan	—	1.4
Excess tax benefits realized on equity-based compensation	8.4	5.7
Equity-based compensation expense	9.1	8.4
Balance, end of period	$ 1,216.0	$ 1,192.9
Retained earnings		
Balance, beginning of period	$ 1,308.3	$ 1,156.0
Net income attributable to UGI Corporation	357.0	292.3
Cash dividends on Common Stock	(98.6)	(93.4)
Balance, end of period	$ 1,566.7	$ 1,354.9
Accumulated other comprehensive income (loss)		
Balance, beginning of period	$ 8.4	$ (55.2)
Net gains on derivative instruments, net of tax	12.3	10.5
Reclassification of net (gains) losses on derivative instruments, net of tax	(7.6)	14.9
Benefit plans, net of tax	0.8	1.1
Foreign currency, net of tax	11.5	1.3
Balance, end of period	$ 25.4	$ (27.4)
Treasury stock		
Balance, beginning of period	$ (32.3)	$ (28.7)
Common Stock issued in connection with employee and director plans, net of tax withheld	46.7	20.8
Dividend reinvestment plan	—	0.8
Repurchases of Common Stock	(21.4)	—
Reacquired Common Stock - employee and director plans	(30.1)	(19.1)
Balance, end of period	$ (37.1)	$ (26.2)
Total UGI Corporation stockholders' equity	$ 2,771.0	$ 2,494.2
Noncontrolling interests		
Balance, beginning of period	$ 1,055.4	$ 1,085.6
Net income attributable to noncontrolling interests, principally in AmeriGas Partners	235.6	194.4
Net gains (losses) on derivative instruments	33.9	(17.7)
Reclassification of net (gains) losses on derivative instruments	(39.1)	37.3
Dividends and distributions	(176.9)	(168.7)
Other	0.9	3.0
Balance, end of period	$ 1,109.8	$ 1,133.9
Total equity	$ 3,880.8	$ 3,628.1

See accompanying notes to condensed consolidated financial statements.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

1. Nature of Operations

UGI Corporation ("UGI") is a holding company that, through subsidiaries and affiliates, distributes and markets energy products and related services. In the United States, we (1) are the general partner and own limited partner interests in a retail propane marketing and distribution business; (2) own and operate natural gas and electric distribution utilities; (3) own all or a portion of electricity generation facilities; and (4) own and operate an energy marketing, midstream infrastructure, storage, natural gas gathering, natural gas production and energy services business. Internationally, we market and distribute propane and other liquefied petroleum gases ("LPG") in Europe and China. We refer to UGI and its consolidated subsidiaries collectively as the "Company" or "we."

We conduct a domestic retail propane marketing and distribution business through AmeriGas Partners, L.P. ("AmeriGas Partners"). AmeriGas Partners is a publicly traded limited partnership that conducts a national propane distribution business through its principal operating subsidiary AmeriGas Propane, L.P. ("AmeriGas OLP") and, prior to its merger with AmeriGas OLP on July 1, 2013 (the "Merger"), AmeriGas OLP's principal operating subsidiary Heritage Operating, L.P. ("HOLP"). AmeriGas OLP after the Merger, and AmeriGas OLP and HOLP prior to the Merger, are collectively referred to herein as the "Operating Partnership." AmeriGas Partners and AmeriGas OLP are Delaware limited partnerships. UGI's wholly owned second-tier subsidiary, AmeriGas Propane, Inc. (the "General Partner"), serves as the general partner of AmeriGas Partners and AmeriGas OLP. We refer to AmeriGas Partners and its subsidiaries together as the "Partnership" and the General Partner and its subsidiaries, including the Partnership, as "AmeriGas Propane." At June 30, 2014, the General Partner held a 1% general partner interest and 25.3% limited partner interest in AmeriGas Partners and an effective 27.1% ownership interest in AmeriGas OLP. Our limited partnership interest in AmeriGas Partners comprises 23,756,882 AmeriGas Partners Common Units ("Common Units"). The remaining 73.7% interest in AmeriGas Partners at June 30, 2014, comprises 69,109,914 publicly held Common Units of which 4,367,362 Common Units are held by a subsidiary of Energy Transfer Partners, L.P. ("ETP") as a result of the January 12, 2012, acquisition of substantially all of ETP's propane operations ("Heritage Propane"). In January 2014 and June 2014, ETP sold 9,200,000 and 8,500,000, respectively, of the Common Units it held in underwritten public offerings, pursuant to its registration rights in its unitholder agreement. AmeriGas Partners did not receive any proceeds from either sale of Common Units by ETP.

Our wholly owned subsidiary, UGI Enterprises, Inc. ("Enterprises"), through subsidiaries conducts (1) an LPG distribution business in France, Belgium, the Netherlands and Luxembourg ("Antargaz"); (2) an LPG distribution business in central, northern and eastern Europe ("Flaga"); (3) an LPG distribution business in the United Kingdom ("AvantiGas"); and (4) an LPG distribution business in the Nantong region of China. We refer to our foreign LPG operations collectively as "UGI International."

Enterprises, through UGI Energy Services, LLC (which was formerly known as UGI Energy Services, Inc. prior to its merger with and into UGI Energy Services, LLC effective October 1, 2013) and its subsidiaries conduct an energy marketing, midstream infrastructure, storage, natural gas gathering, natural gas production and energy services business primarily in the Mid-Atlantic region of the United States. In addition, UGI Energy Services, LLC's wholly owned subsidiary, UGI Development Company ("UGID"), owns all or a portion of electricity generation facilities principally located in Pennsylvania. These businesses are referred to herein collectively as "Midstream & Marketing." UGI Energy Services, LLC subsequent to the merger and UGI Energy Services, Inc. prior to the merger are referred to herein as "Energy Services." Enterprises also conducts heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses in the Mid-Atlantic region through first-tier subsidiaries.

Our natural gas and electric distribution utility businesses are conducted through our wholly owned subsidiary, UGI Utilities, Inc. ("UGI Utilities"), and its subsidiaries UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc.

(“CPG”). UGI Utilities, PNG and CPG own and operate natural gas distribution utilities in eastern, northeastern and central Pennsylvania and in a portion of one Maryland county. UGI Utilities also owns and operates an electric distribution utility in northeastern Pennsylvania (“Electric Utility”). UGI Utilities’ natural gas distribution utility is referred to as “UGI Gas.” UGI Gas, PNG and CPG are collectively referred to as “Gas Utility.” Gas Utility is subject to regulation by the Pennsylvania Public Utility Commission (“PUC”) and, with respect to a small service territory in one Maryland county, the Maryland Public Service Commission, and Electric Utility is subject to regulation by the PUC. Gas Utility and Electric Utility are collectively referred to as “Utilities.”

2. Significant Accounting Policies

Our condensed consolidated financial statements include the accounts of UGI and its controlled subsidiary companies which, except for the Partnership, are majority owned. We report the public’s and ETP’s limited partner interests in the Partnership, and outside ownership interests in other consolidated but less than 100%-owned subsidiaries, as noncontrolling interests. We eliminate all significant intercompany accounts and transactions when we consolidate. Entities in which we do not have control but have significant influence over operating and financial policies are accounted for by the equity method. Investments in business entities that are not publicly traded and in which we hold less than 20% of voting rights are accounted for using the cost method. Undivided interests in natural gas production assets and an electricity generation facility are consolidated on a proportionate basis.

The accompanying condensed consolidated financial statements are unaudited and have been prepared in accordance with the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). They include all adjustments that we consider necessary for a fair statement of the results for the interim periods presented. Such adjustments consisted only of normal recurring items unless otherwise disclosed. The September 30, 2013, condensed consolidated balance sheet data was derived from audited financial statements but does not include all disclosures required by accounting principles generally accepted in the United States of America ("GAAP").

These financial statements should be read in conjunction with the financial statements and related notes included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013 (the "Company's 2013 Annual Financial Statements and Notes"). Due to the seasonal nature of our businesses, the results of operations for interim periods are not necessarily indicative of the results to be expected for a full year.

Restricted Cash. Restricted cash principally represents those cash balances in our commodity futures brokerage accounts that are restricted from withdrawal.

Earnings Per Common Share. Basic earnings per share attributable to UGI Corporation shareholders reflect the weighted-average number of common shares outstanding. Diluted earnings per share attributable to UGI Corporation include the effects of dilutive stock options and common stock awards.

Shares used in computing basic and diluted earnings per share are as follows:

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2014	2013	2014	2013
Denominator (thousands of shares):				
Average common shares outstanding for basic computation	115,370	114,240	115,121	113,693
Incremental shares issuable for stock options and awards	1,678	1,956	1,610	1,582
Average common shares outstanding for diluted computation	117,048	116,196	116,731	115,275

Comprehensive Income. Comprehensive income (loss) comprises net income (loss) and other comprehensive income (loss). Other comprehensive income (loss) principally comprises (1) gains and losses on derivative instruments qualifying as cash flow hedges, net of reclassifications to net income; (2) actuarial gains and losses on postretirement benefit plans, net of associated amortization; and (3) foreign currency translation and intracompany transaction adjustments.

- 7 -

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Changes in accumulated other comprehensive income (“AOCI”) during the three and nine months ended June 30, 2014, are as follows:

Three Months Ended June 30, 2014:	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
Balance, March 31, 2014	$(15.8)	$(23.3)	$63.4	$24.3
Other comprehensive (loss) before reclassification adjustments (after-tax)	—	(0.6)	(0.2)	(0.8)
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	0.4	(0.2)	—	0.2
Reclassification adjustments tax (expense) benefit	(0.2)	(1.3)	—	(1.5)
Reclassification adjustments (after-tax)	0.2	(1.5)	—	(1.3)
Other comprehensive income (loss)	0.2	(2.1)	(0.2)	(2.1)
Add comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	3.2	—	3.2
Other comprehensive income (loss) attributable to UGI	0.2	1.1	(0.2)	1.1
Balance, June 30, 2014	$(15.6)	$(22.2)	$63.2	$25.4

Nine Months Ended June 30, 2014:	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
Balance, September 30, 2013	$(16.4)	$(26.9)	$51.7	$8.4
Other comprehensive income before reclassification adjustments (after-tax)	—	46.2	11.5	57.7
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	1.0	(50.7)	—	(49.7)
Reclassification adjustments tax (expense) benefit	(0.2)	4.0	—	3.8
Reclassification adjustments (after-tax)	0.8	(46.7)	—	(45.9)
Other comprehensive income (loss)	0.8	(0.5)	11.5	11.8
Add comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	5.2	—	5.2
Other comprehensive income attributable to UGI	0.8	4.7	11.5	17.0
Balance, June 30, 2014	$(15.6)	$(22.2)	$63.2	$25.4

For additional information on amounts reclassified from AOCI relating to derivative instruments, see Note 12 to condensed consolidated financial statements.

Income Taxes. In December 2013, the French Parliament approved the Finance Bill for 2014 and amended the Finance Bill for 2013 (collectively, the “Finance Bills”). Among other things, the Finance Bills limit Antargaz’ ability to deduct interest expense for income tax purposes on certain intercompany debt and temporarily increases the corporate surtax rate for a period of two years. Based upon our review of the Finance Bills and interpretive guidance currently available, provisions of the Finance Bills associated with the deductibility of interest expense on certain intercompany debt at Antargaz applies retroactively to such interest expense incurred during Fiscal 2013. In December 2013, the Company recorded additional income taxes of $5.7 to reflect the effects of the retroactive provisions of the Finance Bills associated with the deductibility of interest expense on certain intercompany debt.

Reclassifications. Certain prior period amounts have been reclassified to conform to current period presentation.

UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Use of Estimates. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and costs. These estimates are based on management’s knowledge of current events, historical experience and various other assumptions that are believed to be reasonable under the circumstances. Accordingly, actual results may be different from these estimates and assumptions.

3. Revisions of Condensed Consolidated Financial Statements

During the preparation of the Fiscal 2013 consolidated financial statements, management concluded that it had incorrectly accounted for certain commodity derivative instruments as cash flow hedges. Management had incorrectly applied the hedge accounting criteria when designating certain commodity derivative instruments at its Midstream & Marketing businesses as cash flow hedges. Management has discontinued the use of hedge accounting for Midstream & Marketing’s commodity derivative instruments and reports changes in the fair values of unsettled commodity derivative instruments, and gains and losses on settled commodity derivatives for which the associated forecasted transaction has not yet occurred, in net income.

The Company had previously determined that the impact of the error was not material to the Company’s historical condensed consolidated statements of income for the three and nine months ended June 30, 2013. However, in conjunction with its conclusion that the error was material to the three months ended March 31, 2013, the Company decided to revise its consolidated financial statements for the three and nine months ended June 30, 2013. Accordingly, the accompanying condensed consolidated financial statements as of June 30, 2013, and for the three and nine months ended June 30, 2013, have been revised to report changes in the fair values of unsettled commodity derivative instruments and gains and losses on settled commodity derivative instruments for which the associated forecasted transactions have not yet occurred in cost of sales or revenues in the Condensed Consolidated Statement of Income rather than in other comprehensive income.

The following tables set forth the effects of the revisions on the affected line items within the Company’s previously reported condensed consolidated financial statements as of and for the three and nine months ended June 30, 2013. Also included in the adjustment columns in the tables below are certain other immaterial corrections that the Company made, including, but not limited to, adjustments to correct the Partnership’s accounting for certain customer credits and to correct the classification of deferred income tax assets, as well as certain other minor adjustments related principally to the timing of certain expense and income accruals.

UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Condensed Consolidated Balance Sheet

	June 30, 2013 As Previously Reported	Adjustment	As Revised
Assets:			
Deferred income taxes	$27.3	$(20.7)	$6.6
Property, plant and equipment	$4,325.0	$(1.3)	$4,323.7
Liabilities and equity:			
Deferred income taxes	$956.9	$(23.4)	$933.5
Other noncurrent liabilities	$613.5	$3.4	$616.9
Retained earnings	$1,361.9	$(7.0)	$1,354.9
Accumulated other comprehensive loss	$(30.7)	$3.3	$(27.4)
Noncontrolling interests, principally in AmeriGas Partners	$1,132.2	$1.7	$1,133.9

Condensed Consolidated Statement of Income

	For the three months ended June 30, 2013			For the nine months ended June 30, 2013		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
Revenues	$1,372.3	$2.0	$1,374.3	$5,932.6	$3.1	$5,935.7
Cost of sales	$827.9	$8.9	$836.8	$3,547.3	$(8.3)	$3,539.0
Operating and administrative expenses	$404.7	$2.8	$407.5	$1,297.4	$(1.5)	$1,295.9
Depreciation	$76.5	$(0.1)	$76.4	$220.0	$2.9	$222.9
Other income, net	$(9.0)	$2.0	$(7.0)	$(26.5)	$2.0	$(24.5)
Operating income	$53.1	$(11.6)	$41.5	$835.4	$8.0	$843.4
Interest expense	$(59.2)	$—	$(59.2)	$(179.6)	$(1.2)	$(180.8)
Income (loss) before income taxes	$(6.1)	$(11.6)	$(17.7)	$655.9	$6.8	$662.7
Income taxes	$(9.0)	$3.9	$(5.1)	$(174.1)	$(1.9)	$(176.0)
Net (loss) income	$(15.1)	$(7.7)	$(22.8)	$481.8	$4.9	$486.7
Add net loss (deduct net income) attributable to noncontrolling interests, principally in AmeriGas Partners	$29.8	$2.1	$31.9	$(192.6)	$(1.8)	$(194.4)
Net income attributable to UGI Corporation	$14.7	$(5.6)	$9.1	$289.2	$3.1	$292.3
Basic earnings per common share	$0.13		$0.08	$2.54		$2.57
Diluted earnings per common share	$0.13		$0.08	$2.51		$2.54

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Condensed Consolidated Statement of Comprehensive Income

	For the three months ended June 30, 2013			For the nine months ended June 30, 2013		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
Net (loss) income	$(15.1)	$(7.7)	$(22.8)	$481.8	$4.9	$486.7
Net losses on derivative instruments	$(11.0)	$3.4	$(7.6)	$(11.1)	$3.9	$(7.2)
Reclassifications of net losses on derivative instruments	$8.9	$0.8	$9.7	$59.7	$(7.4)	$52.3
Other comprehensive income	$7.0	$4.2	$11.2	$51.0	$(3.5)	$47.5
Comprehensive (loss) income	$(8.1)	$(3.5)	$(11.6)	$532.8	$1.4	$534.2
Add comprehensive loss (deduct comprehensive income) attributable to noncontrolling interests, principally in AmeriGas Partners	$37.8	$2.1	$39.9	$(212.2)	$(1.8)	$(214.0)
Comprehensive income attributable to UGI Corporation	$29.7	$(1.4)	$28.3	$320.6	$(0.4)	$320.2

Condensed Consolidated Statements of Cash Flows

	For the nine months ended June 30, 2013		
CASH FLOWS FROM OPERATING ACTIVITIES:	As Previously Reported	Adjustment	As Revised
Net income	$481.8	$4.9	$486.7
Depreciation and amortization	$266.3	$2.9	$269.2
Deferred income taxes, net	$35.5	$(3.3)	$32.2
Net change in realized gains and losses deferred as cash flow hedges	$5.0	$(5.0)	$—
Unrealized losses on derivative instruments	$—	$(0.7)	$(0.7)
Other, net	$(11.3)	$7.7	$(3.6)
Net change in:			
Accounts receivable and accrued utility revenues	$(141.1)	$(5.1)	$(146.2)
Inventories	$54.1	$(2.8)	$51.3
Accounts payable	$(26.9)	$1.4	$(25.5)
Other current liabilities	$(73.8)	$—	$(73.8)

Condensed Consolidated Statements of Changes in Equity

	For the nine months ended June 30, 2013		
	As Previously Reported	Adjustment	As Revised
Retained earnings	$1,361.9	$(7.0)	$1,354.9
Accumulated other comprehensive loss	$(30.7)	$3.3	$(27.4)

Noncontrolling interests	$1,132.2	$1.7	$1,133.9

UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

4. Accounting Changes
Adoption of New Accounting Standards
Disclosures about Reclassifications Out of Accumulated Other Comprehensive Income. In Fiscal 2014, the Company adopted new accounting guidance regarding disclosures for items reclassified out of AOCI. The disclosures required by the new accounting guidance are included in Note 2 and Note 12 to the condensed consolidated financial statements. The new disclosures are applied prospectively. As this guidance only affects disclosure requirements, the adoption of this guidance did not impact our results of operations, cash flows or financial position.
Disclosures about Offsetting Assets and Liabilities. Effective October 1, 2013, the Company adopted new accounting guidance requiring entities to disclose both gross and net information about recognized derivative instruments that are offset on the balance sheet as a result of an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. The new disclosures are applied retroactively to all periods presented. The required disclosures are included in Note 11 to the condensed consolidated financial statements. As this guidance only affects disclosure requirements, the adoption of this guidance did not impact our results of operations, cash flows or financial position.
Accounting Standards Not Yet Adopted
Revenue Recognition. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-09, “Revenue from Contracts with Customers.” This ASU supersedes the revenue recognition requirements in Accounting Standards Codification 605, “Revenue Recognition,” and most industry-specific guidance included in the Codification. The standard requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This standard is effective for the Company beginning in fiscal 2018 and allows for either full retrospective adoption or modified retrospective adoption. The Company is in the process of assessing the impact of the adoption of ASU 2014-09 on its results of operations, cash flows and financial position.

Discontinued Operations. In April 2014, the FASB issued authoritative guidance amending existing requirements for reporting discontinued operations. Under the new guidance, discontinued operations reporting will be limited to disposal transactions that represent strategic shifts having a major effect on operations and financial results. The amended guidance also enhances disclosures and requires assets and liabilities of a discontinued operation to be classified as such for all periods presented in the financial statements. Public entities will apply the amended guidance prospectively to all disposals occurring within annual periods beginning on or after December 15, 2014, and interim periods within those years. The Company will adopt this standard on October 1, 2015. Due to the change in requirements for reporting discontinued operations described above, presentation and disclosure of future disposal transactions after adoption may be different than under current standards.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

5. Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	June 30, 2014	September 30, 2013	June 30, 2013
Goodwill (not subject to amortization)	$2,885.1	$2,871.0	$2,834.0
Intangible assets:			
Customer relationships, noncompete agreements and other	$717.3	$706.4	$692.6
Trademarks and tradenames (not subject to amortization)	132.0	131.3	128.4
Gross carrying amount	849.3	837.7	821.0
Accumulated amortization	(259.0)	(227.1)	(212.4)
Intangible assets, net	$590.3	$610.6	$608.6

We amortize customer relationship and noncompete agreement intangible assets over their estimated periods of benefit which do not exceed 15 years. Amortization expense of intangible assets was $13.3 and $35.5 in the three and nine months ended June 30, 2014, respectively, and $13.3 and $40.2 in the three and nine months ended June 30, 2013, respectively. No amortization is included in cost of sales in the Condensed Consolidated Statements of Income. As of June 30, 2014, our expected aggregate amortization expense of intangible assets for the remainder of Fiscal 2014 and for the next four fiscal years is as follows: remainder of Fiscal 2014 — $13.1; Fiscal 2015 — $50.6; Fiscal 2016 — $44.2; Fiscal 2017 — $37.6; Fiscal 2018 — $36.3.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

6. Segment Information

Our operations comprise six reportable segments generally based upon products sold, geographic location and regulatory environment. Our reportable segments comprise: (1) AmeriGas Propane; (2) an international LPG segment comprising Antargaz; (3) an international LPG segment principally comprising Flaga and AvantiGas; (4) Gas Utility; (5) Energy Services; and (6) Electric Generation. We refer to both international segments together as “UGI International” and Energy Services and Electric Generation together as “Midstream & Marketing.”
The accounting policies of our reportable segments are the same as those described in Note 2, “Significant Accounting Policies” in the Company’s 2013 Annual Financial Statements and Notes. We evaluate AmeriGas Propane’s performance principally based upon the Partnership’s earnings before interest expense, income taxes, depreciation and amortization (“Partnership EBITDA”). Although we use Partnership EBITDA to evaluate AmeriGas Propane’s profitability, it should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not a measure of performance or financial condition under GAAP. Our definition of Partnership EBITDA may be different from that used by other companies. We evaluate the performance of our other reportable segments principally based upon their income before income taxes.

Three Months Ended June 30, 2014:

					Midstream & Marketing		UGI International		
	Total	Eliminations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$1,486.7	$(50.8)(c)	$613.2	$128.3	$248.3	$20.5	$249.2	$232.3	$45.7
Cost of sales	$926.5	$(49.6)(c)	$340.8	$49.2	$209.2	$10.5	$164.1	$180.7	$21.6
Segment profit:									
Operating income (loss)	$62.7	$(0.1)	$7.2	$17.1	$23.5	$2.6	$(1.4)	$8.2	$5.6
Loss from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Interest expense	(60.1)	—	(41.4)	(9.8)	(0.5)	—	(6.3)	(1.4)	(0.7)
Income (loss) before income taxes	$2.5	$(0.1)	$(34.2)	$7.3	$23.0	$2.6	$(7.8)	$6.8	$4.9
Partnership EBITDA (a)	$52.2		$55.0						$(2.8)
Noncontrolling interests’ net (loss)	$(33.3)	$—	$(31.0)	$—	$—	$—	$(0.3)	$—	$(2.0)
Depreciation and amortization	$90.0	$—	$47.8	$13.7	$3.3	$2.7	$14.6	$6.2	$1.7
Capital expenditures	$102.4	$1.2	$29.3	$35.9	$11.2	$1.9	$15.6	$4.8	$2.5
Total assets (at period end)	$10,077.7	$(112.8)	$4,345.8	$2,147.4	$542.7	$279.1	$1,784.2	$650.6	$440.7
Bank loans (at period end)	$96.5	$—	$92.5	$—	$—	$—	$—	$4.0	$—
	$2,885.1	$—	$1,939.0	$182.1	$5.6	$—	$651.7	$99.7	$7.0

Goodwill (at period end)

- 14 -

UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Three Months Ended June 30, 2013:

					Midstream & Marketing		UGI International		
	Total	Eliminations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$1,374.3	$(61.5)(c)	$581.7	$126.7	$233.0	$16.3	$249.3	$182.5	$46.3
Cost of sales	$836.8	$(60.1)(c)	$305.7	$52.4	$214.9	$8.5	$148.7	$134.8	$31.9
Segment profit:									
Operating income (loss)	$41.5	$(0.2)	$3.8	$14.2	$6.4	$0.6	$14.6	$6.5	$(4.4)
Income from equity investees	—	—	—	—	—	—	—	—	—
Interest expense	(59.2)	—	(41.2)	(9.2)	(0.6)	—	(6.2)	(1.2)	(0.8)
(Loss) income before income taxes	$(17.7)	$(0.2)	$(37.4)	$5.0	$5.8	$0.6	$8.4	$5.3	$(5.2)
Partnership EBITDA (a)			$56.3						
Noncontrolling interests' net (loss) income	$(31.9)	$—	$(31.7)	$—	$—	$—	$(0.3)	$0.1	$—
Depreciation and amortization	$91.8	$(0.1)	$52.4	$13.1	$2.1	$2.6	$14.0	$6.1	$1.6
Capital expenditures	$107.6	$(0.1)	$26.3	$37.3	$22.0	$4.4	$11.7	$4.0	$2.0
Total assets (at period end)	$9,806.8	$(95.9)	$4,386.8	$2,143.7	$437.0	$267.2	$1,771.7	$543.1	$353.2
Bank loans (at period end)	$135.9	$—	$80.0	$—	$45.5	$—	$—	$10.4	$—
Goodwill (at period end)	$2,834.0	$—	$1,929.2	$182.1	$2.8	$—	$619.2	$93.7	$7.0

(a) The following table provides a reconciliation of Partnership EBITDA to AmeriGas Propane operating income:

Three Months Ended June 30,	2014	2013
Partnership EBITDA	$55.0	$56.3
Depreciation and amortization	(47.8)	(52.4)
Noncontrolling interests (i)	—	(0.1)
Operating income	$7.2	$3.8

(i) Principally represents the General Partner's 1.01% interest in AmeriGas OLP.

(b) Corporate & Other results principally comprise (1) Electric Utility, (2) Enterprises' heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses ("HVAC"), (3) net gains and losses on Midstream & Marketing's commodity derivative instruments, and net gains and losses on AmeriGas Propane's commodity derivative instruments entered into beginning April 1, 2014, that are not associated with current period transactions, (4) net expenses of UGI's captive general liability insurance company, and (5) UGI Corporation's unallocated corporate and general expenses and interest income. Corporate & Other assets principally comprise cash, short-term investments, the assets of Electric Utility and HVAC, and an intercompany loan. The intercompany loan and associated interest is removed in the segment presentation.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

(c) Principally represents the elimination of intersegment transactions among Midstream & Marketing, Gas Utility and AmeriGas Propane.

Nine Months Ended June 30, 2014:

					Midstream & Marketing		UGI International		
	Total	Elim-inations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$6,965.9	$(281.0)(c)	$3,152.7	$880.0	$1,109.9	$66.4	$1,086.5	$802.8	$148.6
Cost of sales	$4,357.7	$(278.0)(c)	$1,809.0	$463.5	$894.2	$30.5	$713.3	$635.1	$90.1
Segment profit:									
Operating income (loss)	$1,015.0	$—	$471.7	$233.7	$166.8	$16.9	$94.7	$32.8	$(1.6)
Loss from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Interest expense	(178.9)	—	(125.0)	(26.6)	(2.5)	—	(19.1)	(3.8)	(1.9)
Income (loss) before income taxes	$836.0	$—	$346.7	$207.1	$164.3	$16.9	$75.5	$29.0	$(3.5)
Partnership EBITDA (a)	$613.7		$616.5						$(2.8)
Noncontrolling interests' net income (loss)	$235.6	$—	$237.6	$—	$—	$—	$—	$—	$(2.0)
Depreciation and amortization	$271.7	$(0.1)	$149.3	$40.7	$9.1	$8.0	$39.9	$20.0	$4.8
Capital expenditures	$290.5	$—	$80.3	$98.8	$41.3	$13.0	$36.7	$13.6	$6.8
Total assets (at period end)	$10,077.7	$(112.8)	$4,345.8	$2,147.4	$542.7	$279.1	$1,784.2	$650.6	$440.7
Bank loans (at period end)	$96.5	$—	$92.5	$—	$—	$—	$—	$4.0	$—
Goodwill (at period end)	$2,885.1	$—	$1,939.0	$182.1	$5.6	$—	$651.7	$99.7	$7.0

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

Nine Months Ended June 30, 2013:

					Midstream & Marketing		UGI International		
	Total	Elim-inations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Revenues	$5,935.7	$(181.1)(c)	$2,636.9	$743.6	$764.8	$ 48.7	$1,121.2	$659.0	$ 142.6
Cost of sales	$3,539.0	$(176.2)(c)	$1,367.4	$372.7	$650.5	$ 29.0	$714.4	$507.1	$74.1
Segment profit:									
Operating income	$843.4	$(1.1)	$407.5	$189.7	$76.5	$ 1.4	$129.9	$30.6	$8.9
Income from equity investees	0.1	—	—	—	—	—	0.1	—	—
Interest expense	(180.8)	—	(125.4)	(28.1)	(2.4)	—	(19.0)	(3.8)	(2.1)
Income before income taxes	$662.7	$(1.1)	$282.1	$161.6	$74.1	$ 1.4	$111.0	$26.8	$6.8
Partnership EBITDA (a)			$557.1						
Noncontrolling interests' net income	$194.4	$—	$194.2	$—	$—	$ —	$0.1	$0.1	$—
Depreciation and amortization	$269.2	$(0.1)	$153.4	$38.4	$5.6	$ 7.5	$42.3	$17.4	$4.7
Capital expenditures	$292.5	$(1.1)	$80.7	$90.2	$54.8	$ 15.4	$37.1	$10.3	$5.1
Total assets (at period end)	$9,806.8	$(95.9)	$4,386.8	$2,143.7	$437.0	$ 267.2	$1,771.7	$543.1	$353.2
Bank loans (at period end)	$135.9	$—	$80.0	$—	$45.5	$ —	$—	$10.4	$—
Goodwill (at period end)	$2,834.0	$—	$1,929.2	$182.1	$2.8	$ —	$619.2	$93.7	$7.0

(a) The following table provides a reconciliation of Partnership EBITDA to AmeriGas Propane operating income:

Nine Months Ended June 30,	2014	2013
Partnership EBITDA	$616.5	$557.1
Depreciation and amortization	(149.3)	(153.4)
Noncontrolling interests (i)	4.5	3.8
Operating income	$471.7	$407.5

(i) Principally represents the General Partner's 1.01% interest in AmeriGas OLP.

(b) Corporate & Other results principally comprise (1) Electric Utility, (2) Enterprises' heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses ("HVAC"), (3) net gains and losses on Midstream & Marketing's commodity derivative instruments, and net gains and losses on AmeriGas Propane's commodity derivative instruments entered into beginning April 1, 2014, that are not associated with current period transactions, (4) net expenses of UGI's captive general liability insurance company, and (5) UGI Corporation's unallocated corporate and general expenses and interest income. Corporate & Other assets principally comprise cash, short-term investments, the assets of Electric Utility and HVAC, and an intercompany loan. The intercompany loan and associated interest is removed in the segment presentation.

(c)

Principally represents the elimination of intersegment transactions among Midstream & Marketing, Gas Utility and AmeriGas Propane.

7. Energy Services Accounts Receivable Securitization Facility

Energy Services has a receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper that is currently scheduled to expire in October 2014. The Receivables Facility provides Energy Services with the ability to borrow up to $150 of eligible receivables during the period November 1, 2013 to May 31, 2014, and up to $75 of eligible receivables during the period June 1, 2014 to October 31, 2014.
Under the Receivables Facility, Energy Services transfers, on an ongoing basis and without recourse, its trade accounts receivable to its wholly owned, special purpose subsidiary, Energy Services Funding Corporation ("ESFC"), which is consolidated for financial statement purposes. ESFC, in turn, has sold and, subject to certain conditions, may from time to time sell, an undivided interest in some or all of the receivables to a major bank and, prior to October 1, 2013, a commercial paper conduit of a major bank. ESFC was created and has been structured to isolate its assets from creditors of Energy Services and its affiliates, including UGI. Trade receivables sold to the bank or, prior to October 1, 2013, the commercial paper conduit, remain on the Company's balance sheet and the Company reflects a liability equal to the amount advanced by the bank or the commercial paper conduit. The Company records interest expense on amounts owed to the bank or, prior to October 1, 2013, the commercial paper conduit. Energy Services continues to service, administer and collect trade receivables on behalf of the bank or commercial paper issuer, as applicable.
During the nine months ended June 30, 2014 and 2013, Energy Services transferred trade receivables to ESFC totaling $1,073.1 and $766.1, respectively. During the nine months ended June 30, 2014 and 2013, ESFC sold an aggregate $196.0 and $224.0, respectively, of undivided interests in its trade receivables to the bank or commercial paper conduit, as applicable. At June 30, 2014, the outstanding balance of ESFC receivables was $57.7 and there were none sold to the bank. At June 30, 2013, the outstanding balance of ESFC receivables was $58.2 and there was $9.5 sold to the commercial paper conduit.

8. Utility Regulatory Assets and Liabilities and Regulatory Matters

For a description of the Company's regulatory assets and liabilities other than those described below, see Note 8 to the Company's 2013 Annual Financial Statements and Notes. UGI Utilities does not recover a rate of return on its regulatory assets. The following regulatory assets and liabilities associated with Gas Utility and Electric Utility are included in our accompanying Condensed Consolidated Balance Sheets:

	June 30, 2014	September 30, 2013	June 30, 2013
Regulatory assets:			
Income taxes recoverable	$107.2	$106.1	$104.7
Underfunded pension and postretirement plans	89.2	94.5	177.8
Environmental costs	14.6	17.1	16.6
Deferred fuel and power costs	9.4	8.3	4.1
Removal costs, net	15.6	13.3	12.1
Other	6.6	5.6	5.6
Total regulatory assets	$242.6	$244.9	$320.9
Regulatory liabilities:			
Postretirement benefits	$17.5	$16.5	$14.2
Environmental overcollections	1.6	2.6	2.9
Deferred fuel and power refunds	—	8.3	14.2

State tax benefits—distribution system repairs	9.3	8.4	8.0
Other	1.9	1.5	0.7
Total regulatory liabilities	$30.3	$37.3	$40.0

Deferred fuel and power—costs and refunds. Gas Utility's tariffs and Electric Utility's tariffs contain clauses which permit recovery of all prudently incurred purchased gas and power costs through the application of purchased gas cost ("PGC") rates in the case of Gas Utility and default service ("DS") rates in the case of Electric Utility. The clauses provide for periodic adjustments to PGC and DS rates for differences between the total amount of purchased gas and electric generation supply costs collected from

customers and recoverable costs incurred. Net undercollected costs are classified as a regulatory asset and net overcollected costs are classified as a regulatory liability.
Gas Utility uses derivative financial instruments to reduce volatility in the cost of natural gas it purchases for firm-residential, commercial and industrial ("retail core-market") customers. Realized and unrealized gains or losses on natural gas derivative financial instruments are included in deferred fuel costs or refunds. Net unrealized gains (losses) on such contracts at June 30, 2014, September 30, 2013 and June 30, 2013 were $0.7, $(1.7) and $(1.4), respectively.
Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Because most of these contracts do not currently qualify for the normal purchases and normal sales exception under GAAP, the fair values of these contracts are required to be recognized on the Condensed Consolidated Balance Sheets with an associated adjustment to regulatory assets or liabilities in accordance with GAAP related to rate-regulated entities. At June 30, 2014, September 30, 2013, and June 30, 2013, the fair values of Electric Utility's electricity supply contracts were net gains (losses) of $0.8, $(4.8) and $(6.1), respectively, which amounts are reflected in current derivative financial instrument assets and liabilities on the Condensed Consolidated Balance Sheets with equal and offsetting amounts reflected in deferred fuel and power costs or refunds in the table above.

In order to reduce volatility associated with a substantial portion of its electric transmission congestion costs, Electric Utility obtains financial transmission rights ("FTRs"). FTRs are derivative financial instruments that entitle the holder to receive compensation for electricity transmission congestion charges when there is insufficient electricity transmission capacity on the electric transmission grid. Because Electric Utility is entitled to fully recover its DS costs, realized and unrealized gains or losses on FTRs are included in deferred fuel and power costs or deferred fuel and power refunds. Unrealized gains or losses on FTRs at June 30, 2014, September 30, 2013, and June 30, 2013, were not material.

9. Defined Benefit Pension and Other Postretirement Plans

In the U.S., we currently sponsor one defined benefit pension plan for employees hired prior to January 1, 2009, of UGI, UGI Utilities, PNG, CPG and certain of UGI's other domestic wholly owned subsidiaries ("Pension Plan"). We also provide postretirement health care benefits to certain retirees and postretirement life insurance benefits to nearly all domestic active and retired employees. In addition, Antargaz employees are covered by certain defined benefit pension and postretirement plans.

Net periodic pension expense and other postretirement benefit costs include the following components:

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$2.3	$2.8	$0.1	$0.2
Interest cost	6.5	5.9	0.2	0.2
Expected return on assets	(7.3)	(6.9)	(0.1)	(0.1)
Amortization of:				
Prior service cost (benefit)	0.1	0.1	(0.1)	(0.1)
Actuarial loss	1.9	3.7	—	0.1
Net benefit cost	3.5	5.6	0.1	0.3
Change in associated regulatory liabilities	—	—	0.9	0.8
Net expense	$3.5	$5.6	$1.0	$1.1

	Pension Benefits		Other Postretirement Benefits	
	Nine Months Ended June 30,		Nine Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$7.0	$8.5	$0.4	$0.5
Interest cost	19.4	17.6	0.7	0.7
Expected return on assets	(22.0)	(20.7)	(0.4)	(0.4)
Amortization of:				
Prior service cost (benefit)	0.2	0.2	(0.4)	(0.2)
Actuarial loss	5.7	11.2	0.1	0.3
Net benefit cost	10.3	16.8	0.4	0.9
Change in associated regulatory liabilities	—	—	2.7	2.4
Net expense	$10.3	$16.8	$3.1	$3.3

Pension Plan assets are held in trust and consist principally of publicly traded, diversified equity and fixed income mutual funds and UGI Common Stock. It is our general policy to fund amounts for Pension Plan benefits equal to at least the minimum contribution set forth in applicable employee benefit laws. Based upon current assumptions, the Company estimates that it will be required to contribute approximately $6.9 to the Pension Plan during the remainder of Fiscal 2014. During the nine months ended June 30, 2014 and 2013, the Company made cash contributions to the Pension Plan of $11.0 and $13.4, respectively. UGI Utilities has established a Voluntary Employees' Beneficiary Association ("VEBA") trust to pay UGI Gas' and Electric Utility's postretirement health care and life insurance benefits referred to above by depositing into the VEBA the annual amount of postretirement benefit costs determined under GAAP. The difference between such amounts calculated under GAAP and the amounts included in UGI Gas' and Electric Utility's rates is deferred for future recovery from, or refund to, ratepayers.

We also sponsor unfunded and non-qualified defined benefit supplemental executive retirement plans ("Supplemental Defined Benefit Plans"). We recorded pre-tax expense associated with these plans of $0.6 and $0.8 in the three months ended June 30, 2014 and 2013, respectively. We recorded pre-tax expense associated with these plans of $2.3 and $2.4 in the nine months ended June 30, 2014 and 2013, respectively.

UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

10. Commitments and Contingencies

Environmental Matters
UGI Utilities
CPG is party to a Consent Order and Agreement (“CPG-COA”) with the Pennsylvania Department of Environmental Protection (“DEP”) requiring CPG to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which manufactured gas plant (“MGP”) related facilities were operated (“CPG MGP Properties”) and to plug a minimum number of non-producing natural gas wells per year. In addition, PNG is a party to a Multi-Site Remediation Consent Order and Agreement (“PNG-COA”) with the DEP. The PNG-COA requires PNG to perform annually a specified level of activities associated with environmental investigation and remediation work at certain properties on which MGP-related facilities were operated (“PNG MGP Properties”). Under these agreements, environmental expenditures relating to the CPG MGP Properties and the PNG MGP Properties are capped at $1.8 and $1.1, respectively, in any calendar year. The CPG-COA is scheduled to terminate at the end of 2018. The PNG-COA terminates in 2019 but may be terminated by either party effective at the end of any two-year period beginning with the original effective date in March 2004. At June 30, 2014 and 2013, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $11.4 and $14.4, respectively. In accordance with GAAP related to rate-regulated entities, we have recorded associated regulatory assets in equal amounts.
From the late 1800s through the mid-1900s, UGI Utilities and its former subsidiaries owned and operated a number of MGPs prior to the general availability of natural gas. Some constituents of coal tars and other residues of the manufactured gas process are today considered hazardous substances under the Superfund Law and may be present on the sites of former MGPs. Between 1882 and 1953, UGI Utilities owned the stock of subsidiary gas companies in Pennsylvania and elsewhere and also operated the businesses of some gas companies under agreement. Pursuant to the requirements of the Public Utility Holding Company Act of 1935, by the early 1950s UGI Utilities divested all of its utility operations other than certain Pennsylvania operations, including those which now constitute UGI Gas and Electric Utility.
UGI Utilities does not expect its costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to its results of operations because (1) UGI Gas is currently permitted to include in rates, through future base rate proceedings, a five-year average of such prudently incurred remediation costs and (2) CPG and PNG are currently receiving regulatory recovery of estimated environmental investigation and remediation costs associated with Pennsylvania sites. At June 30, 2014, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas was material.
From time to time, UGI Utilities is notified of sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by UGI Utilities or owned or operated by its former subsidiaries. Such parties generally investigate the extent of environmental contamination or perform environmental remediation. Management believes that under applicable law UGI Utilities should not be liable in those instances in which a former subsidiary owned or operated an MGP. There could be, however, significant future costs of an uncertain amount associated with environmental damage caused by MGPs outside Pennsylvania that UGI Utilities directly operated, or that were owned or operated by former subsidiaries of UGI Utilities if a court were to conclude that (1) the subsidiary’s separate corporate form should be disregarded or (2) UGI Utilities should be considered to have been an operator because of its conduct with respect to its subsidiary’s MGP.

Other Matters

Federal Trade Commission Investigation of Propane Grill Cylinder Filling Practices. On or about November 4, 2011, the General Partner received notice that the Federal Trade Commission ("FTC") had initiated an antitrust and consumer protection investigation into certain practices of the Partnership relating to the filling of portable propane cylinders. On February 2, 2012, the Partnership received a Civil Investigative Demand from the FTC that requested documents and information concerning, among other things, (i) the Partnership's decision, in 2008, to reduce the volume of propane in cylinders it sells to consumers from 17 pounds to 15 pounds, and (ii) cross-filling, related service arrangements and communications regarding the foregoing with competitors. The Partnership responded to that subpoena and cooperated with subsequent requests for information. On March 27, 2014, the FTC issued an administrative complaint against the Partnership and UGI alleging that the General Partner and one of its competitors colluded in 2008 to persuade its common customer, Walmart Stores, Inc., to accept the cylinder fill reduction from 17 pounds to 15 pounds. The complaint does not seek monetary remedies. The Partnership and UGI filed their Answer to the complaint on

April 18, 2014, and believe that they have good defenses to the FTC's claims. We are unable to reasonably estimate the impact, if any, arising from this claim.

Purported Class Action Lawsuits. Following the issuance of the FTC's administrative complaint described above, more than 25 class action lawsuits have been filed in multiple jurisdictions against the Partnership/UGI Corporation and a competitor by certain of their direct and indirect customers. The class action lawsuits allege that the Partnership and its competitor colluded in 2008 to reduce the fill level and combined to persuade its common customer, Walmart Stores, Inc., to accept that fill reduction, resulting in increased cylinder costs to retailers and end-user customers in violation of federal and certain state antitrust laws. The claims seek treble damages, injunctive relief, attorneys' fees and costs on behalf of the putative classes. We believe these lawsuits will eventually be consolidated by a multidistrict litigation panel. We are unable to reasonably estimate the impact, if any, arising from such litigation. We believe we have strong defenses to the claims and intend to vigorously defend against them.

In addition to the matters described above, there are other pending claims and legal actions arising in the normal course of our businesses. Although we cannot predict the final results of these pending claims and legal actions, we believe, after consultation with counsel, that the final outcome of these matters will not have a material effect on our consolidated financial position, results of operations or cash flows.

11. Fair Value Measurements

Derivative Financial Instruments

The following table presents our financial assets and financial liabilities that are measured at fair value on a recurring basis for each of the fair value hierarchy levels, including both current and noncurrent portions, as of June 30, 2014, September 30, 2013 and June 30, 2013:

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

	Asset (Liability) Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total
June 30, 2014:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$6.8	$6.4	$—	$13.2
Foreign currency contracts	$—	$0.5	$—	$0.5
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$(4.5)	$(6.6)	$—	$(11.1)
Foreign currency contracts	$—	$(4.8)	$—	$(4.8)
Interest rate contracts	$—	$(25.2)	$—	$(25.2)
Cross-currency swaps	$—	$(2.0)	$—	$(2.0)
September 30, 2013:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$2.1	$21.2	$—	$23.3
Foreign currency contracts	$—	$0.9	$—	$0.9
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$(9.7)	$(6.3)	$—	$(16.0)
Foreign currency contracts	$—	$(7.2)	$—	$(7.2)
Interest rate contracts	$—	$(31.0)	$—	$(31.0)
Cross-currency swaps	$—	$(1.2)	$—	$(1.2)
June 30, 2013:				
Assets:				
Derivative financial instruments:				
Commodity contracts	$2.2	$7.4	$—	$9.6
Foreign currency contracts	$—	$1.0	$—	$1.0
Interest rate contracts	$—	$8.1	$—	$8.1
Liabilities:				
Derivative financial instruments:				
Commodity contracts	$(8.0)	$(24.1)	$—	$(32.1)
Foreign currency contracts	$—	$(1.7)	$—	$(1.7)
Interest rate contracts	$—	$(46.9)	$—	$(46.9)

The fair values of our Level 1 exchange-traded commodity futures and option contracts and non-exchange-traded commodity futures and forward contracts are based upon actively-quoted market prices for identical assets and liabilities. The remainder of our derivative financial instruments are designated as Level 2. The fair values of certain non-exchange-traded commodity derivatives designated as Level 2 are based upon indicative price quotations available through brokers, industry price publications or recent market transactions and related market indicators. For commodity option contracts designated as Level 2 which are not traded on an exchange, we use a Black Scholes option pricing model that considers time value and volatility of the underlying commodity. The fair values of our Level 2 interest rate contracts and foreign currency contracts are based upon third-party quotes

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

or indicative values based on recent market transactions. There were no transfers between Level 1 and Level 2 during the periods presented.

Other Financial Instruments

The carrying amounts of other financial instruments included in current assets and current liabilities (except for current maturities of long-term debt) approximate their fair values because of their short-term nature. At June 30, 2014, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,556.2 and $3,805.4, respectively. At June 30, 2013, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,493.8 and $3,621.0, respectively. We estimate the fair value of long-term debt by using current market rates and by discounting future cash flows using rates available for similar type debt (Level 2).

Financial instruments other than derivative financial instruments, such as our short-term investments and trade accounts receivable, could expose us to concentrations of credit risk. We limit our credit risk from short-term investments by investing only in investment-grade commercial paper, money market mutual funds, securities guaranteed by the U.S. Government or its agencies and FDIC insured bank deposits. The credit risk from trade accounts receivable is limited because we have a large customer base that extends across many different U.S. markets and several foreign countries. For information regarding concentrations of credit risk associated with our derivative financial instruments, see Note 12 and below.

Disclosures about Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities are presented net by counterparty on our Condensed Consolidated Balance Sheets if the right of offset exists. Our derivative financial instruments include both those that are executed on an exchange through brokers and centrally cleared and over-the-counter transactions. Exchange contracts utilize a financial intermediary, exchange, or clearinghouse to enter, execute, or clear the transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Certain over-the-counter and exchange contracts contain contractual rights of offset through master netting arrangements, derivative clearing agreements, and contract default provisions. In addition, the contracts are subject to conditional rights of offset through counterparty nonperformance, insolvency, or other conditions.

In general, most of our over-the-counter transactions and all exchange contracts are subject to collateral requirements. Types of collateral generally include cash or letters of credit. Cash collateral paid by us to our derivative counterparties, if any, is reflected in the table below to offset derivative liabilities. Cash collateral received by us from our derivative counterparties, if any, is reflected in the table below to offset derivative assets. Certain other accounts receivable and accounts payable balances recognized on our Condensed Consolidated Balance Sheets with our derivative counterparties are not included in the table below but could reduce our net exposure to such counterparties because such balances are subject to master netting or similar arrangements.

	Gross Amounts Recognized	Gross Amounts Offset in the Balance Sheet	Net Amounts Presented in the Balance Sheet
June 30, 2014:			
Derivative assets	$31.9	$(18.2)	$13.7
Derivative (liabilities)	$(61.3)	$18.2	$(43.1)
September 30, 2013:			
Derivative assets	$26.3	$(2.1)	$24.2
Derivative (liabilities)	$(57.5)	$2.1	$(55.4)

June 30, 2013:			
Derivative assets	$25.1	$(6.4)	$18.7
Derivative (liabilities)	$(87.1)	$6.4	$(80.7)

12. Disclosures about Derivative Instruments and Hedging Activities

UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

We are exposed to certain market risks related to our ongoing business operations. Management uses derivative financial and commodity instruments, among other things, to manage these risks. The primary risks managed by derivative instruments are (1) commodity price risk, (2) interest rate risk and (3) foreign currency exchange rate risk. Although we use derivative financial and commodity instruments to reduce market risk associated with forecasted transactions, we do not use derivative financial and commodity instruments for speculative or trading purposes. The use of derivative instruments is controlled by our risk management and credit policies which govern, among other things, the derivative instruments we can use, counterparty credit limits and contract authorization limits.

Commodity Price Risk

In order to manage market price risk associated with the Partnership's fixed-price programs, which permit customers to lock in the prices they pay for propane principally during the months of October through March, the Partnership uses over-the-counter derivative commodity instruments, principally price swap contracts. In addition, the Partnership, certain other domestic business units and our UGI International operations also use over-the-counter price swap and option contracts to reduce commodity price volatility associated with a portion of their forecasted LPG purchases. In addition, the Partnership from time to time enters into price swap and put option agreements to reduce the effects of short-term commodity price volatility.

Gas Utility's tariffs contain clauses that permit recovery of all of the prudently incurred costs of natural gas it sells to retail core-market customers, including the cost of financial instruments used to economically hedge purchased gas costs. As permitted and agreed to by the PUC pursuant to Gas Utility's annual PGC filings, Gas Utility currently uses New York Mercantile Exchange ("NYMEX") natural gas futures and option contracts to reduce commodity price volatility associated with a portion of the natural gas it purchases for its retail core-market customers. At June 30, 2014 and 2013, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 10.9 million dekatherms and 11.7 million dekatherms, respectively. At June 30, 2014, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 9 months. Gains and losses on natural gas futures contracts and any gains on natural gas option contracts are recorded in regulatory assets or liabilities on the Condensed Consolidated Balance Sheets in accordance with GAAP related to rate-regulated entities and reflected in cost of sales through the PGC mechanism (see Note 8).
Electric Utility's DS tariffs permit the recovery of all prudently incurred costs of electricity it sells to DS customers, including the cost of financial instruments used to hedge electricity costs. Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Because most of these contracts currently do not qualify for the normal purchases and normal sales exception under GAAP, the fair values of these contracts are required to be recognized on the balance sheet. At June 30, 2014 and 2013, the fair values of Electric Utility's forward purchase power agreements comprising gains of $0.8 and losses of $6.1, respectively, are reflected in current derivative financial instrument assets and liabilities and other noncurrent liabilities in the accompanying Condensed Consolidated Balance Sheets. In accordance with GAAP related to rate-regulated entities, Electric Utility has recorded equal and offsetting amounts in regulatory assets and liabilities. At June 30, 2014 and 2013, the volumes of Electric Utility's forward electricity purchase contracts were 315.8 million kilowatt hours and 327.4 million kilowatt hours, respectively. At June 30, 2014, the maximum period over which these contracts extend is 11 months.

In order to reduce volatility associated with a substantial portion of its electricity transmission congestion costs, Electric Utility obtains FTRs through an annual allocation process and by purchases of FTRs at monthly auctions. Midstream & Marketing purchases FTRs to economically hedge electricity transmission congestion costs associated with its fixed-price electricity sales contracts. FTRs are derivative financial instruments that entitle the holder to receive compensation for electricity transmission congestion charges that result when there is insufficient electricity transmission capacity on the electric transmission grid. Because Electric Utility is entitled to fully recover its DS costs, gains and losses on Electric Utility FTRs are recorded in regulatory assets or liabilities in accordance with GAAP related to rate-regulated entities and reflected in cost of sales through the DS recovery mechanism (see Note 8). Midstream & Marketing from time to time also enters into New York Independent System Operator ("NYISO") capacity swap contracts to economically hedge the locational basis differences for customers it serves on the NYISO electricity grid. At June 30, 2014 and 2013, the volumes associated with Electric Utility FTRs totaled 232.2 million kilowatt hours and 260.6 million kilowatt hours, respectively. Midstream & Marketing's FTRs and capacity swap contracts are recorded at fair value with changes in fair value reflected in cost of sales. At June 30, 2014 and 2013, the volumes associated with Midstream & Marketing's FTRs and NYISO capacity swap contracts totaled 427.7 million kilowatt hours and 1,609.2 million kilowatt hours, respectively.

In order to manage market price risk relating to fixed-price sales contracts for natural gas and electricity, Midstream & Marketing enters into NYMEX and over-the-counter natural gas futures contracts, Intercontinental Exchange ("ICE") natural gas basis swap contracts, and electricity futures contracts. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to economically hedge the price of a portion of its anticipated future sales of electricity from its electricity generation facilities. In addition, Midstream & Marketing uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later sale of natural gas or propane. During the three months ended March 31, 2014, Energy Services determined that it could no longer assert the normal purchases and normal sales exception under GAAP for new contracts entered into for the forward purchase of natural gas and pipeline transportation and, as a result, began accounting for these contracts at fair value on the balance sheet with changes in fair value reflected in net income. These contracts, as well as other Midstream & Marketing derivative instruments described above, are not accounted for as hedges under GAAP. These derivative instruments are recorded at fair value with changes in fair value reflected in income.

At June 30, 2014 and 2013, total volumes associated with Midstream & Marketing's natural gas futures, forward and pipeline transportation contracts totaled 83.0 million dekatherms and 19.4 million dekatherms, respectively. Total volumes associated with Midstream & Marketing's electricity call contracts and electricity put contracts totaled 492.5 million kilowatt hours and 193.2 million kilowatt hours at June 30, 2014, and 927.2 million kilowatt hours and 451.0 million kilowatt hours at June 30, 2013, respectively. At June 30, 2014, the volumes associated with Midstream & Marketing's natural gas storage and propane storage NYMEX contracts totaled 0.5 million dekatherms and 2.9 million gallons, respectively. At June 30, 2013, the volumes associated with Midstream & Marketing's natural gas storage and propane storage NYMEX contracts totaled 2.7 million dekatherms and 1.8 million gallons, respectively.

In order to reduce operating expense volatility, UGI Utilities from time to time enters into NYMEX gasoline futures and swap contracts for a portion of gasoline volumes expected to be used in the operation of its vehicles and equipment. Associated volumes, fair values and effects on net income were not material for all periods presented.

At June 30, 2014 and 2013, total volumes associated with LPG commodity derivative instruments totaled 274.3 million gallons and 236.7 million gallons, respectively. At June 30, 2014, for those LPG commodity derivative instruments accounted for as cash flow hedges, the maximum period over which we are hedging our exposure to the variability in cash flows associated with LPG commodity price risk is 21 months with a weighted average of 6 months.

We account for commodity price risk contracts at our UGI International business units, and at the Partnership for commodity derivative instruments entered into prior to April 1, 2014, as cash flow hedges. Effective April 1, 2014, the Partnership determined that on a prospective basis it would not elect cash flow hedge accounting for its commodity derivative transactions. All unrealized and realized gains and losses on the Partnership's derivative commodity transactions entered into beginning April 1, 2014, are included as a component of cost of sales on the Condensed Consolidated Statements of Income. Changes in the fair values of contracts qualifying for cash flow hedge accounting are recorded in AOCI and, with respect to the Partnership's contracts, also in noncontrolling interests, to the extent effective in offsetting changes in the underlying commodity price risk. When earnings are affected by the hedged commodity, gains or losses are recorded in cost of sales on the Condensed Consolidated Statements of Income. At June 30, 2014, the amount of net gains associated with commodity price risk hedges expected to be reclassified into earnings during the next twelve months based upon current fair values is $4.0.

Interest Rate Risk

Antargaz' and Flaga's long-term debt agreements have interest rates that are generally indexed to short-term market interest rates. Antargaz has entered into pay-fixed, receive-variable interest rate swap agreements to hedge the underlying euribor rate of interest on its variable-rate term loan, and Flaga has entered into pay-fixed, receive-variable interest rate swap agreements to hedge the underlying euribor rate of interest on its term loans, in each case through the respective scheduled maturity dates. As of June 30, 2014 and 2013, the total notional amount of existing variable-rate debt subject to interest rate swap agreements (excluding Flaga's cross-currency swap as described below) was €401.1 and €440.5, respectively.

Our domestic businesses' long-term debt is typically issued at fixed rates of interest. As these long-term debt issues mature, we typically refinance such debt with new debt having interest rates reflecting then-current market conditions. In order to reduce market rate risk on the underlying benchmark rate of interest associated with near- to medium-term forecasted issuances of fixed-rate debt, from time to time we enter into interest rate protection agreements ("IRPAs"). At June 30, 2014, we had no unsettled IRPAs. At June 30, 2013, the total notional amount of unsettled IRPAs was $173.

We account for interest rate swaps and IRPAs as cash flow hedges. Changes in the fair values of interest rate swaps and IRPAs are recorded in AOCI and, with respect to the Partnership, also in noncontrolling interests, to the extent effective in offsetting changes in the underlying interest rate risk, until earnings are affected by the hedged interest expense. At such time, gains and losses are recorded in interest expense. At June 30, 2014, the amount of net losses associated with interest rate hedges (excluding pay-fixed, receive-variable interest rate swaps) expected to be reclassified into earnings during the next twelve months is $2.7.

Foreign Currency Exchange Rate Risk

In order to reduce volatility, Antargaz hedges a portion of its anticipated U.S. dollar-denominated LPG product purchases through the use of forward foreign currency exchange contracts. The amount of dollar-denominated purchases of LPG associated with such contracts generally represents approximately 15% to 30% of estimated dollar-denominated purchases of LPG forecasted to occur during the heating-season months of October through March. At June 30, 2014 and 2013, we were hedging a total of $219.8 and $170.3 of U.S. dollar-denominated LPG purchases, respectively. At June 30, 2014, the maximum period over which we are hedging our exposure to the variability in cash flows associated with dollar-denominated purchases of LPG is 33 months with a weighted average of 15 months. From time to time we also enter into forward foreign currency exchange contracts to reduce the volatility of the U.S. dollar value on a portion of our International Propane euro-denominated net investments. At June 30, 2014 and 2013, we had no euro-denominated net investment hedges.

We account for foreign currency exchange contracts associated with anticipated purchases of U.S. dollar-denominated LPG as cash flow hedges. Changes in the fair values of these foreign currency exchange contracts are recorded in AOCI, to the extent effective in offsetting changes in the underlying currency exchange rate risk, until earnings are affected by the hedged LPG purchase, at which time gains and losses are recorded in cost of sales. At June 30, 2014, the amount of net losses associated with currency rate risk (other than net investment hedges) expected to be reclassified into earnings during the next twelve months based upon current fair values is $3.6. Gains and losses on net investment hedges are included in AOCI until such foreign operations are liquidated.

From time to time, the Company may enter into foreign currency exchange transactions to economically hedge the local-currency purchase price of anticipated foreign business acquisitions. These transactions do not qualify for hedge accounting treatment and any changes in fair value are recorded in other income, net.

Cross-Currency Swaps

During Fiscal 2013, Flaga entered into a cross-currency swap to hedge its exposure to the variability in expected future cash flows associated with foreign currency and interest rate risk resulting from the issuance of $52 of U.S. dollar-denominated variable-rate debt. The cross-currency hedge includes initial and final exchanges of principal from a fixed euro denomination to a fixed U.S. denominated amount, to be exchanged at a specified rate, which was determined by the market spot rate on the date of issuance. The cross-currency swap also includes an interest rate swap of a fixed foreign-denominated interest rate to a fixed U.S. dollar-denominated interest rate. We have designated this cross-currency swap as a cash flow hedge. Changes in the fair value of our cross-currency swap are recorded in AOCI to the extent effective in offsetting changes in the underlying foreign currency exchange and interest rate risk. At June 30, 2014, the amount of net losses associated with this cross-currency swap expected to be reclassified into earnings over the next twelve months is not material.

Derivative Financial Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative financial instrument counterparties. Our derivative financial instrument counterparties principally comprise large energy companies and major U.S. and international financial institutions. We maintain credit policies with regard to our counterparties that we believe reduce overall credit risk. These policies include evaluating and monitoring our counterparties' financial condition, including their credit ratings, and entering into agreements with counterparties that govern credit limits or entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. Certain of these agreements call for the posting of collateral by the counterparty or by the Company in the forms of letters of credit, parental guarantees or cash. Additionally, our natural gas and electricity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2014 and 2013, restricted cash in brokerage accounts totaled $5.9 and $6.0, respectively. Although we have concentrations of credit risk associated with derivative financial instruments, the maximum amount of loss, based upon the gross fair values of the derivative financial instruments, we would incur if these counterparties failed to perform according to the terms of their contracts was not material at June 30, 2014. Certain of the Partnership's derivative contracts have credit-risk-related contingent features that may require the posting of additional collateral in the event of a downgrade of the Partnership's debt rating. At June 30, 2014, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

The following table provides information regarding the fair values and balance sheet locations of our derivative assets and liabilities existing as of June 30, 2014 and 2013:

	Derivative Assets Balance Sheet Location	Fair Value June 30, 2014	2013	Derivative (Liabilities) Balance Sheet Location	Fair Value June 30, 2014	2013
Derivatives Designated as Hedging Instruments:						
Commodity contracts	Derivative financial instruments and Other assets	$7.0	$5.3	Derivative financial instruments and Other noncurrent liabilities	$(3.1)	$(17.9)
Foreign currency contracts	Derivative financial instruments and Other assets	0.5	1.0	Derivative financial instruments and Other noncurrent liabilities	(4.8)	(0.4)
Cross-currency contracts		—	—	Derivative financial instruments and Other noncurrent liabilities	(2.0)	—
Interest rate contracts	Derivative financial instruments	—	8.1	Derivative financial instruments and Other noncurrent liabilities	(25.2)	(46.9)
Total Derivatives Designated as Hedging Instruments		$7.5	$14.4		$(35.1)	$(65.2)
Derivatives Subject to Utility Rate Regulation:						
Commodity contracts	Derivative financial instruments	$1.6	$0.1	Derivative financial instruments	$—	$(7.6)
Derivatives Not Designated as Hedging Instruments:						
Commodity contracts	Derivative financial instruments and Other assets	$6.4	$4.2	Derivative financial instruments and Other noncurrent liabilities	$(9.8)	$(6.6)
Foreign currency contracts	Derivative financial instruments	—	—	Derivative financial instruments	—	(1.3)

Total Derivatives Not Designated as Hedging Instruments	$6.4	$4.2	$(9.8)	$(7.9)
Amounts above offset in the Balance Sheet	(1.8)	—	1.8	—
Total Derivatives	$13.7	$18.7	$(43.1)	$(80.7)

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

The following tables provide information on the effects of derivative instruments on the Condensed Consolidated Statements of Income and changes in AOCI and noncontrolling interests for the three and nine months ended June 30, 2014 and 2013:

Three Months Ended June 30,	Gain (Loss) Recognized in AOCI and Noncontrolling Interests		Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income		Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
	2014	2013	2014	2013	
Cash Flow Hedges:					
Commodity contracts	$(1.7)	$(17.1)	$4.3	$(8.2)	Cost of sales
Foreign currency contracts	1.1	(0.3)	(0.2)	—	Cost of sales
Cross-currency contracts	—	—	(0.1)	—	Interest expense
Interest rate contracts	(0.6)	14.0	(3.9)	(3.6)	Interest expense / other income, net
Total	$(1.2)	$(3.4)	$0.1	$(11.8)	

Derivatives Not Designated as Hedging Instruments:	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
	2014	2013	
Commodity contracts	$(4.9)	$(5.7)	Cost of sales
Commodity contracts	—	(0.1)	Operating expenses / other income, net
Foreign currency contracts	—	(0.9)	Other income, net
Total	$(4.9)	$(6.7)	

Nine Months Ended June 30,	Gain (Loss) Recognized in AOCI and Noncontrolling Interests		Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income		Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
	2014	2013	2014	2013	
Cash Flow Hedges:					
Commodity contracts	$59.5	$(21.6)	$66.5	$(51.4)	Cost of sales
Foreign currency contracts	(1.6)	(1.4)	(3.7)	(0.1)	Cost of sales
Cross-currency contracts	(1.1)	—	(0.2)	—	Interest expense
Interest rate contracts	(4.1)	23.0	(12.0)	(10.6)	Interest expense / other income, net
Total	$52.7	$—	$50.6	$(62.1)	

Derivatives Not Designated as Hedging Instruments:	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
	2014	2013	
Commodity contracts	$(14.3)	$8.1	Cost of sales
Commodity contracts	0.1	—	Operating expenses / other

			income, net
Foreign currency contracts	—	(1.1)	Other income, net
Total	$(14.2)	$7.0	

The amounts of derivative gains or losses representing ineffectiveness were not material for the three- and nine-month periods ended June 30, 2014 and 2013.

We are also a party to a number of other contracts that have elements of a derivative instrument. These contracts include, among others, binding purchase orders and contracts that provide for the purchase and delivery, or sale, of natural gas, LPG and electricity and service contracts that require the counterparty to provide commodity storage, transportation or capacity service to meet our normal sales commitments. Although many of these contracts have the requisite elements of a derivative instrument, these contracts qualify for normal purchases and normal sales exception accounting under GAAP because they provide for the delivery of products or services in quantities that are expected to be used in the normal course of operating our business and the price in the contract is based on an underlying that is directly associated with the price of the product or service being purchased or sold.

13. Inventories

Inventories comprise the following:

	June 30, 2014	September 30, 2013	June 30, 2013
Non-utility LPG and natural gas	$222.6	$230.0	$194.6
Gas Utility natural gas	45.7	78.9	43.1
Materials, supplies and other	63.7	56.6	66.3
Total inventories	$332.0	$365.5	$304.0

At June 30, 2014, UGI Utilities is a party to three storage contract administrative agreements ("SCAAs") having terms of one to three years. Pursuant to SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon commencement of the SCAAs, will receive a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the term of the SCAAs. The historical cost of natural gas storage inventories released under the SCAAs, which represents a portion of Gas Utility's total natural gas storage inventories, and any exchange receivable (representing amounts of natural gas inventories used by the other parties to the agreement but not yet replenished), are included in the caption "Gas Utility natural gas" in the table above. As of June 30, 2014, UGI Utilities had SCAAs with Energy Services and a non-affiliate. The carrying values of natural gas storage inventories released under SCAAs with non-affiliates at June 30, 2014 and September 30, 2013, comprising 2.1 billion cubic feet ("bcf") and 0.6 bcf of natural gas, were $8.9 and $2.4, respectively. UGI Utilities did not have any SCAAs with non-affiliates at June 30, 2013.

14. Debt

On March 26, 2014, UGI Utilities issued in a private placement $175 of 4.98% Senior Notes due March 26, 2044 ("4.98% Senior Notes"). The 4.98% Senior Notes were issued pursuant to a Note Purchase Agreement dated October 30, 2013, between UGI Utilities and certain note purchasers. The 4.98% Senior Notes are unsecured and rank equally with UGI Utilities' existing outstanding senior debt. The net proceeds from the sale of the 4.98% Senior Notes were used to repay $175 of borrowings under UGI Utilities' 364-day term loan credit agreement scheduled to expire in September 2014. The 4.98% Senior Notes include the usual and customary covenants for similar type notes including, among others, maintenance of existence, payment of taxes when due, compliance with laws and maintenance of insurance. The 4.98% Senior Notes also contain restrictive and financial covenants including a requirement that UGI Utilities not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined therein, of 0.65 to 1.00.

In June 2014, AmeriGas OLP entered into an Amended and Restated Credit Agreement ("Amended and Restated Credit Agreement") with a group of banks which provides for borrowings up to $525 (including a sublimit of $125 for letters of credit). The Amended and Restated Credit Agreement amends and restates AmeriGas OLP's prior Credit Agreement entered into with a group of banks in June 2011, as amended from time to time. The Amended and Restated Credit Agreement permits AmeriGas OLP to borrow at prevailing interest rates, including the base rate, defined as the higher of the Federal Funds rate plus 0.50% or the agent bank's prime rate, or at a one-week, one-, two-, three-, or six-month Eurodollar Rate, as defined in the Amended and Restated Credit Agreement, plus a margin. The

Amended and Restated Credit Agreement reduces the applicable margin on base rate borrowings to a range of 0.5% to 1.5% (from a range of 0.75% to 1.75% previously); reduces the applicable margin on Eurodollar Rate borrowings to a range of 1.5% to 2.5% (from a range of 1.75% to 2.75% previously); and reduces the facility fee to a range of 0.3% to 0.45% (from a range of 0.3% to 0.5% previously). The aforementioned margins and facility fees are dependent upon AmeriGas Partners' ratio of debt to earnings before interest expense, income taxes, depreciation and amortization (each as defined in the Amended and Restated Credit Agreement). The Amended and Restated Credit Agreement expires on June 18, 2019.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES
Notes to Condensed Consolidated Financial Statements
(unaudited)
(Millions of dollars and euros, except per share amounts)

The Amended and Restated Credit Agreement restricts the incurrence of additional indebtedness and also restricts certain liens, guarantees, investments, loans and advances, payments, mergers, consolidations, asset transfers, transactions with affiliates, sales of assets, acquisitions and other transactions. The Amended and Restated Credit Agreement requires that AmeriGas OLP and AmeriGas Partners maintain ratios of total indebtedness to EBITDA, as defined, below certain thresholds. In addition, the Partnership must maintain a minimum ratio of EBITDA to interest expense, as defined and as calculated on a rolling four-quarter basis. Generally, as long as no default exists or would result therefrom, AmeriGas OLP is permitted to make cash distributions not more frequently than quarterly in an amount not to exceed available cash, as defined, for the immediately preceding calendar quarter.

15. Subsequent Event

On July 29, 2014, UGI's Board of Directors approved a 3-for-2 common stock split. UGI will issue three shares for every two common shares outstanding. The new shares will be distributable September 5, 2014, to shareholders of record on August 22, 2014. Basic and diluted earnings per share attributable to UGI Corporation stockholders and dividends declared per share for the three- and nine-month periods ended June 30, 2014 and 2013, have been reflected on a pre-split basis.

The following table presents pro forma basic and diluted earnings per share attributable to UGI Corporation stockholders to reflect the effect of the 3-for-2 common stock split:

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2014	2013	2014	2013
Basic earnings per share:				
As reported	$0.18	$0.08	$3.10	$2.57
Pro forma	$0.12	$0.05	$2.07	$1.71
Diluted earnings per share:				
As reported	$0.18	$0.08	$3.06	$2.54
Pro forma	$0.12	$0.05	$2.04	$1.69

ITEM 2: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements

Information 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, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Such statements use forward-looking words such as "believe," "plan," "anticipate," "continue," "estimate," "expect," "may," or other similar words. These statements discuss plans, strategies, events or developments that we expect or anticipate will or may occur in the future.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, we caution you that actual results almost always vary from assumed facts or bases, and the differences between actual results and assumed facts or bases can be material, depending on the circumstances. When considering forward-looking statements, you should keep in mind the following important factors that could affect our future results and could cause those results to differ materially from those expressed in our forward-looking statements: (1) adverse weather conditions resulting in reduced demand; (2) cost volatility and availability of propane and other LPG, oil, electricity, and natural gas and the capacity to transport product to our customers; (3) changes in domestic and foreign laws and regulations, including safety, tax, consumer protection and accounting matters; (4) inability to timely recover costs through utility rate proceedings; (5) the impact of pending and future legal proceedings; (6) competitive pressures from the same and alternative energy sources; (7) failure to acquire new customers and retain current customers thereby reducing or limiting any increase in revenues; (8) liability for environmental claims; (9) increased customer conservation measures due to high energy prices and improvements in energy efficiency and technology resulting in reduced demand; (10) adverse labor relations; (11) large customer, counterparty or supplier defaults; (12) liability in excess of insurance coverage for personal injury and property damage arising from explosions and other catastrophic events, including acts of terrorism, resulting from operating hazards and risks incidental to generating and distributing electricity and transporting, storing and distributing natural gas and LPG and the impact of regulatory enforcement activity related thereto, ranging from financial penalties, required reporting or operational measures up to suspension of applicable certificates of public convenience; (13) political, regulatory and economic conditions in the United States and in foreign countries, including the current conflicts in the Middle East and those involving Russia, and foreign currency exchange rate fluctuations, particularly the euro; (14) capital market conditions, including reduced access to capital markets and interest rate fluctuations; (15) changes in commodity market prices resulting in significantly higher cash collateral requirements; (16) reduced distributions from subsidiaries; (17) the timing of development of Marcellus Shale gas production; (18) the timing and success of our acquisitions, commercial initiatives and investments to grow our businesses; and (19) our ability to successfully integrate acquired businesses and achieve anticipated synergies.

These factors, and those factors set forth in Item 1A. Risk Factors in (i) our Quarterly Reports on Form 10-Q for the fiscal quarters ended December 31, 2013 and March 31, 2014 and (ii) our Annual Report on Form 10-K for the fiscal year ended September 30, 2013, are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other unknown or unpredictable factors could also have material adverse effects on our business, financial condition or future results. We undertake no obligation to update publicly any forward-looking statement whether as a result of new information or future events except as required by the federal securities laws.

ANALYSIS OF RESULTS OF OPERATIONS

The following analyses compare our results of operations for the three months ended June 30, 2014 ("2014 three-month period") with the three months ended June 30, 2013 ("2013 three-month period") and the nine months ended June 30, 2014 ("2014 nine-month period") with the nine months ended June 30, 2013 ("2013 nine-month period"). Our analyses of results of operations should be read in conjunction with the segment information included in Note 6 to the condensed consolidated financial statements.

Executive Overview

Because most of our businesses sell or distribute energy products used in large part for heating purposes, our results are significantly influenced by temperatures in our service territories, particularly during the heating season months of October through March. As a result, our earnings are significantly higher in our first and second fiscal quarters.

Three Months Ended June 30, 2014 Results

We recorded net income attributable to UGI Corporation of $20.6 million (equal to $0.18 per diluted share) for the 2014 three-month period compared to net income attributable to UGI Corporation of $9.1 million (equal to $0.08 per diluted share) for the 2013 three-month period. Net income attributable to UGI Corporation in the 2014 three-month period includes net after-tax gains of $4.1 million on commodity derivative instruments not associated with current-period transactions at Midstream & Marketing and net after-tax losses of $0.6 million on AmeriGas Propane's commodity derivative instruments entered into beginning April 1, 2014, not associated with current period transactions. These amounts have been included in "Corporate & Other" in the business unit summary table below. Net income attributable to UGI Corporation in the 2013 three-month period includes net after-tax losses of $3.3 million related to Midstream & Marketing's commodity derivative instruments not associated with current period transactions. Adjusted net income attributable to UGI excluding the effects of these commodity derivative instrument gains and losses was $17.1 million (equal to $0.15 per diluted share) in the 2014 three-month period compared to adjusted net income of $12.4 million (equal to $0.11 per diluted share) in the 2013 three-month period.

The increase in adjusted net income attributable to UGI in the 2014 three-month period reflects the effects of improved results at our Midstream & Marketing business units and, to a much lesser extent, improved contributions from Gas Utility and AmeriGas Propane. These increases in net income attributable to UGI were partially offset by lower net income from our International Propane operations primarily reflecting the effects of significantly warmer spring weather.

Nine Months Ended June 30, 2014 Results

We recorded net income attributable to UGI of $357.0 million (equal to $3.06 per diluted share) for the 2014 nine-month period compared to net income attributable to UGI of $292.3 million (equal to $2.54 per diluted share) for the 2013 nine-month period. Net income attributable to UGI Corporation in the 2014 nine-month period includes net after-tax gains of $0.6 million on commodity derivative instruments not associated with current-period transactions at Midstream & Marketing and net after-tax losses of $0.6 million on AmeriGas Propane's commodity derivative instruments entered into beginning April 1, 2014, not associated with current period transactions. These amounts have been included in "Corporate & Other" in the business unit summary table below. Net income attributable to UGI Corporation in the 2013 nine-month period includes net after-tax gains of $4.7 million related to Midstream & Marketing commodity derivative instruments not associated with current period transactions. Results in the 2014 nine-month period also reflect the retroactive effect to Fiscal 2013 of a change in tax laws in France, which increased tax expense and reduced 2014 nine-month period net income by $5.7 million (equal to $0.05 per diluted share). Adjusted net income attributable to UGI excluding the effects of these commodity derivative instrument gains and losses and the retroactive impact of the change in French tax laws was $362.7 million (equal to $3.11 per diluted share) in the 2014 nine-month period compared to $287.6 million (equal to $2.49 per diluted share) in the prior-year nine-month period.

The significant increase in adjusted net income attributable to UGI in the 2014 nine-month period reflects the effects of significantly colder and more volatile Fiscal 2014 winter weather at Midstream & Marketing and significantly colder weather at Gas Utility and in AmeriGas Propane's service territory east of the Rocky Mountains. The significant increase in operating results from our domestic business units was partially offset by the effects of record warm temperatures at our European LPG business units. During the nine months ended June 30, 2014, net income attributable to UGI increased $62.3 million at Midstream & Marketing, $28.4 million at Gas Utility, and $13.2 million at AmeriGas Propane, respectively. Midstream & Marketing's operating results were substantially above last year as periods of extreme cold winter weather in the Mid-Atlantic and Northeast U.S. served by Energy Services resulted in significant locational basis price differences for natural gas and also increased the demand for, and the value of, winter peaking services. Midstream & Marketing's Electric Generation business results also benefited from higher unit margins and higher production at its Hunlock Creek and Conemaugh electricity generating facilities. The improved results at Gas Utility principally reflect the effects on core market volumes of weather that was nearly 12% colder than the prior year. The improved results at AmeriGas Propane also reflect the retail volume effects of significantly colder weather in the U.S. east of the Rocky Mountains offset in part by the unfavorable impacts on retail volumes and distribution costs from wholesale supply challenges in certain regions of the U.S. caused by industry-wide storage and transportation issues exacerbated by prolonged periods of unusually cold winter weather. UGI International earnings declined $30.7 million principally due to record warm winter and spring temperatures at our European LPG businesses which caused reduced retail volumes sold.

Our UGI International base-currency results are translated into U.S. dollars based upon exchange rates experienced during each of the reporting periods. Although the foreign currency exchange rates during the 2014 three- and nine-month periods were slightly higher than in the prior year, such differences did not have a material impact on UGI International net income attributable to UGI.

We believe each of our business units has sufficient liquidity in the forms of revolving credit facilities, and with respect to Energy Services also an accounts receivable securitization facility, to fund business operations during Fiscal 2014 (see Financial Condition and Liquidity below).

Non-GAAP Financial Measures - Adjusted Net Income Attributable to UGI and Adjusted Diluted Earnings Per Share

UGI management uses “adjusted net income attributable to UGI” and “adjusted earnings per diluted share,” both of which are non-GAAP financial measures, when evaluating UGI’s overall performance. Adjusted net income attributable to UGI is net income attributable to UGI after excluding (1) net after-tax gains and losses on commodity derivative instruments not associated with current-period transactions at Midstream & Marketing and net after-tax gains and losses on commodity derivative instruments not associated with current-period transactions at AmeriGas Propane for commodity derivative instruments entered into beginning April 1, 2014, and (2) those items that management regards as highly unusual in nature and not expected to recur.

Midstream & Marketing accounts for realized and unrealized gains and losses on its commodity derivative instruments in earnings as a component of cost of sales or revenues on the Condensed Consolidated Statements of Income. Effective April 1, 2014, AmeriGas Propane determined that on a prospective basis it would not elect cash flow hedge accounting for its commodity derivative transactions. All unrealized and realized gains and losses on AmeriGas Propane’s derivative commodity transactions entered into beginning April 1, 2014, are included as a component of cost of sales on the Condensed Consolidated Statements of Income. Volatility in net income at UGI can occur as a result of gains and losses on commodity derivative instruments not associated with current period transactions but included in earnings in accordance with generally accepted accounting principles (“GAAP”). These gains and losses result principally from recording changes in the fair values of unsettled commodity derivative instruments and realized gains and losses on commodity derivative instruments that settled in the normal course during the period but are associated with transactions forecasted to occur in a future period.

Non-GAAP financial measures are not in accordance with, or an alternative to, GAAP and should be considered in addition to, and not as a substitute for, the comparable GAAP measures. Management believes that these non-GAAP measures provide meaningful information to investors about UGI’s performance because they eliminate the impact of (1) gains and losses on Midstream & Marketing’s and, beginning April 1, 2014, AmeriGas Propane’s commodity derivative instruments that are not associated with current-period transactions and (2) those items that management regards as highly unusual in nature and not expected to recur.
The following table reconciles consolidated net income attributable to UGI, the most directly comparable GAAP measure, to adjusted net income attributable to UGI, and reconciles diluted earnings per share, the most comparable GAAP measure, to adjusted diluted earnings per share, to reflect the adjustments referred to above:

(Millions of dollars, except per share)	For the Three Months ended June 30,		For the Nine Months ended June 30,	
	2014	2013	2014	2013
Adjusted net income attributable to UGI Corporation:				
Net income attributable to UGI Corporation	$20.6	$9.1	$357.0	$292.3
Net (gains) losses on Midstream & Marketing’s commodity derivative instruments not associated with current period transactions (a)	(4.1)	3.3	(0.6)	(4.7)
Net losses on AmeriGas Propane commodity derivative instruments entered into beginning April 1, 2014, not associated with current period transactions	0.6	—	0.6	—
Retroactive impact of change in French tax law	—	—	5.7	—
Adjusted net income attributable to UGI Corporation	$17.1	$12.4	$362.7	$287.6
Adjusted diluted earnings per share:				
Earnings per share - diluted	$0.18	$0.08	$3.06	$2.54
Net (gains) losses on Midstream & Marketing’s commodity derivative instruments not associated with current period transactions (a)	(0.03)	0.03	—	(0.05)
	—	—	—	—

Net losses on AmeriGas Propane commodity derivative instruments entered into beginning April 1, 2014, not associated with current period transactions				
Retroactive impact of change in French tax law	—	—	0.05	—
Adjusted earnings per share - diluted	$0.15	$0.11	$3.11	$2.49

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

(a) - includes the impact of rounding.

2014 three-month period compared to the 2013 three-month period

Net income (loss) attributable to UGI Corporation by Business Unit:

	Three Months Ended June 30,					
	2014		2013		Variance - Favorable (Unfavorable)	
(Millions of dollars)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane	$(1.8)	(8.7)%	$(3.5)	(38.5)%	$1.7	(48.6)%
UGI International	0.4	1.9 %	8.4	92.3 %	(8.0)	(95.2)%
Gas Utility	5.7	27.7 %	3.0	33.0 %	2.7	90.0 %
Midstream & Marketing	14.1	68.4 %	3.9	42.9 %	10.2	261.5 %
Corporate & Other (a)	2.2	10.7 %	(2.7)	(29.7)%	4.9	N.M.
Net income attributable to UGI Corporation	$20.6	100.0 %	$9.1	100.0 %	$11.5	126.4 %

N.M. — Variance is not meaningful.

(a) Includes net after-tax gains (losses) on commodity derivative instruments not associated with current-period transactions at Midstream & Marketing of $4.1 million and $(3.3) million during the three months ended June 30, 2014 and 2013, respectively. Also includes net after-tax losses on commodity derivative instruments not associated with current period transactions at AmeriGas Propane for commodity derivative instruments entered into beginning April 1, 2014 of $(0.6) million during the three months ended June 30, 2014.

AmeriGas Propane:

For the three months ended June 30,	2014	2013	Increase (decrease)	
(Millions of dollars)				
Revenues	$613.2	$581.7	$31.5	5.4 %
Total margin (a)	$272.4	276.0	$(3.6)	(1.3)%
Operating and administrative expenses	$225.1	$227.2	$(2.1)	(0.9)%
Partnership EBITDA (b)	$55.0	$56.3	$(1.3)	(2.3)%
Operating income (b)	$7.2	$3.8	$3.4	89.5 %
Retail gallons sold (millions)	215.6	224.7	(9.1)	(4.0)%
Degree days—% (warmer) colder than normal (c)	(9.3)%	0.5 %	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the 2014 three-month period excludes net pre-tax losses of $2.8 million on AmeriGas Propane unsettled commodity derivative instruments entered into beginning April 1, 2014, not associated with current-period transactions.

(b) Partnership EBITDA (earnings before interest expense, income taxes, depreciation and amortization) should not be considered as an alternative to net income (as an indicator of operating performance) and is not a measure of performance or financial condition under GAAP. Management uses Partnership EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 6 to condensed consolidated financial statements). Partnership EBITDA for the three months ended June 30, 2013, includes transition expenses of $9.9 million associated with the integration of Heritage Propane which was acquired in January 2012.

(c) Deviation from average heating degree-days for the 30-year period 1971-2000 based upon national weather statistics provided by the National Oceanic and Atmospheric Administration (“NOAA”) for 335 airports in the United States, excluding Alaska.

AmeriGas Propane’s retail gallons sold in the 2014 three-month period decreased 4.0% from the 2013 three-month period reflecting, among other things, average temperatures based upon heating degree days that were significantly warmer than normal and the prior year. Based upon heating degree-day data, temperatures in the Partnership's service territories during the 2014 three-month

period averaged approximately 9.3% warmer than normal while temperatures in the prior-year period averaged approximately 0.5% colder than normal.
Retail propane revenues increased $36.6 million during the 2014 three-month period reflecting the effects of higher average retail selling prices ($56.9 million) which were the result of higher propane product costs partially offset by the lower retail volumes sold ($20.3 million). Wholesale propane revenues decreased $5.1 million for the 2014 three-month period on lower wholesale sales. Average daily wholesale propane commodity prices during the 2014 three-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 16% higher than such prices during the prior-year three-month period. Total revenues from fee income and other ancillary sales and services in the 2014 three-month period were the same as the prior-year period. Total cost of sales increased $35.1 million during the 2014 three-month period principally reflecting the effects on retail propane cost of sales of higher average propane product costs ($50.7 million) partially offset by effects of the lower retail volumes sold ($10.8 million) and the lower wholesale sales.

Total margin decreased $3.6 million in the 2014 three-month period principally reflecting lower retail propane total margin ($3.4 million). The decrease in retail propane total margin reflects the effects of the decrease in retail volumes sold partially offset by modestly higher average retail propane unit margins.

Partnership EBITDA in the 2014 three-month period decreased $1.3 million principally reflecting the lower total margin ($3.6 million) partially offset by slightly lower operating and administrative expenses. Operating and administrative expenses in the prior-year period include $9.9 million of Heritage Propane transition expenses. Excluding the effects of the Heritage Propane transition expenses in the prior year, Partnership operating and administrative expenses increased slightly during the 2014 three-month period principally reflecting higher payroll and benefits, general insurance, vehicle repair and maintenance and advertising expenses. Operating income in the 2014 three-month period was $3.4 million greater than the prior-year period, notwithstanding the $1.3 million decline in Partnership EBITDA, principally reflecting lower depreciation expense.
UGI International:

For the three months ended June 30,	2014	2013	Increase (decrease)	
(Millions of dollars)				
Revenues	$481.5	$431.8	$49.7	11.5 %
Total margin (a)	$136.7	$148.3	$(11.6)	(7.8)%
Operating and administrative expenses	$112.5	$107.7	$4.8	4.5 %
Operating income	$6.8	$21.1	$(14.3)	(67.8)%
(Loss) income before income taxes	$(1.0)	$13.7	$(14.7)	(107.3)%
Retail gallons sold (millions) (b)	117.2	126.6	(9.4)	(7.4)%
Antargaz degree days—% (warmer) colder than normal (c)	(19.8)%	19.7 %	—	—
Flaga degree days—% (warmer) than normal (c)	(15.5)%	(7.2)%	—	—

(a) Total margin represents total revenues less total cost of sales.
(b) Excludes retail gallons from operations in China.
(c) Deviation from average heating degree days for the 30-year period 1981-2010 at locations in our Antargaz and Flaga service territories.

Based upon heating degree day data, temperatures in each of our European LPG operations were significantly warmer than normal and warmer than the prior-year period. Total retail gallons sold were only slightly lower than the prior year as the effects on retail sales from the significantly warmer weather in Europe in the 2014 three-month period were partially offset by incremental retail gallons associated with BP’s former LPG business in Poland acquired by Flaga in September 2013 (“BP Poland acquisition”). During the 2014 three-month period, the average wholesale commodity price for propane in northwest Europe was approximately 2% higher than in the prior-year period while the average wholesale commodity price for butane was approximately 3% higher than the prior-year period.

UGI International base-currency results are translated into U.S. dollars based upon exchange rates experienced during each of the reporting periods. The functional currency of a significant portion of our UGI International results is the euro. During the 2014 and 2013 three-month periods, the average un-weighted translation rate was approximately $1.37 and $1.30 per euro, respectively. The differences in euro to U.S. dollar translation rates and, to a lesser extent, the differences in the exchange rates of the British pound sterling to the U.S. dollar at AvantiGas, did not have a material impact on net income attributable to UGI.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

UGI International revenues were $49.7 million greater than the prior-year period principally the result of higher total revenues at Flaga ($47.7 million) reflecting incremental wholesale and retail volumes from the BP Poland acquisition and the currency conversion effects of the stronger euro in the 2014 three-month period. Revenues at Antargaz were about equal to the prior-year period as lower base-currency revenues resulting from the lower LPG volumes sold was substantially offset by the currency conversion effects of the stronger euro and higher revenues from natural gas activities. UGI International cost of sales increased to $344.8 million in the 2014 three-month period from $283.5 million in the prior-year period. The increase includes higher cost of sales at Flaga ($44.5 million) reflecting incremental wholesale and retail cost of sales resulting from the BP Poland acquisition and the currency conversion effects of the slightly stronger euro and higher cost of sales at Antargaz ($15.4 million) principally reflecting higher cost of sales associated with natural gas marketing activities and the currency conversion effects of the stronger euro. Total UGI International margin decreased $11.6 million during the 2014 three-month period principally reflecting the effects of the lower retail LPG gallons sold and slightly lower average retail unit margins at Antargaz partially offset principally by the effects on total margin of the stronger euro.
UGI International operating income and income (loss) before income taxes during the 2014 three-month period declined $14.3 million and $14.7 million, respectively. The declines in operating income and income (loss) before income taxes principally reflect the lower total margin ($11.6 million) and increased operating and administrative costs at Flaga ($3.6 million), principally the result of the BP Poland acquisition.

Gas Utility:

For the three months ended June 30,	2014		2013		Increase		
(Millions of dollars)							
Revenues	$128.3		$126.7		$1.6	1.3	%
Total margin (a)	$79.1		$74.3		$4.8	6.5	%
Operating and administrative expenses	$47.0		$43.5		$3.5	8.0	%
Operating income	$17.1		$14.2		$2.9	20.4	%
Income before income taxes	$7.3		5.0		$2.3	46.0	%
System throughput—billions of cubic feet (“bcf”) —							
Core market	9.2		8.8		0.4	4.5	%
Total	37.5		35.9		1.6	4.5	%
Degree days—% (warmer) than normal (b)	(6.3	)%	(7.1	)%	—	—	

(a) Total margin represents total revenues less total cost of sales.
(b) Deviation from average heating degree days for the 15-year period 1995-2009 based upon weather statistics provided by NOAA for airports located within Gas Utility’s service territory.

Temperatures in the Gas Utility service territory in the 2014 three-month period based upon heating degree days were 6.3% warmer than normal and slightly colder than the prior-year three-month period. Total distribution system throughput was slightly higher principally reflecting a net increase in large firm and interruptible delivery service volumes and to a lesser extent higher core market volumes. Gas Utility’s core market customers comprise firm-residential, commercial and industrial (“retail core-market”) customers who purchase their gas from Gas Utility and, to a much lesser extent, residential and small commercial customers who purchase their gas from alternate suppliers. Gas Utility system throughput to core-market customers was above last year principally reflecting the effects of customer growth, due principally to conversions from oil prompted by sustained lower natural gas prices and high oil prices.

Gas Utility revenues increased $1.6 million during the 2014 three-month period principally reflecting higher revenues from core market customers ($3.6 million) and greater revenues from large delivery service customers on higher throughput substantially offset by lower revenues from off-system sales ($5.5 million). The increase in core market revenues principally reflects the effects of the higher core market volumes partially offset by the effects of slightly lower average purchased gas cost (“PGC”) rates. Under Gas Utility’s PGC recovery mechanisms, Gas Utility records the cost of gas associated with sales to retail core-market customers at amounts included in PGC rates. The difference between actual gas costs and the amounts included in rates is deferred on the balance sheet as a regulatory asset or liability and represents amounts to be collected from or refunded to customers in a future period. As a result of this PGC recovery mechanism, increases or decreases in the cost of gas associated with retail core-market customers have no direct effect on retail core-market margin. Gas Utility's cost of gas was $49.2 million in the 2014 three-month period compared with $52.4 million in the prior-year period principally reflecting the effects on cost of sales of the lower off-

system sales ($5.5 million) and the lower average PGC rates partially offset by the greater retail core-market volumes sold ($2.7 million).
Gas Utility total margin increased $4.8 million in the 2014 three-month period principally reflecting higher core market total margin and greater large firm delivery service total margin. The higher core market and large firm delivery service total margin reflects the effects of the greater throughput to these customers.

The increases in Gas Utility operating income and income before income taxes during the 2014 three-month period principally reflects the greater total margin ($4.8 million) partially offset by higher operating and administrative expenses and, with respect to income before income taxes, slightly higher interest expense from higher long-term debt outstanding.

Midstream & Marketing:

For the three months ended June 30,	2014	2013	Increase		
(Millions of dollars)					
Revenues (a)	$265.7	$248.4	$17.3	7.0	%
Total margin (b)	$49.1	$25.9	$23.2	89.6	%
Operating and administrative expenses	$16.9	$14.7	$2.2	15.0	%
Operating income	$26.1	$7.0	$19.1	272.9	%
Income before income taxes	$25.6	$6.4	$19.2	300.0	%

(a) Amounts are net of intercompany revenues between Midstream & Marketing’s Energy Services and Electric Generation segments.

(b) Total margin represents total revenues less total cost of sales. Amounts exclude net pre-tax gains (losses) from changes in the fair values of Midstream & Marketing’s unsettled commodity derivative instruments and gains (losses) on settled commodity instruments not associated with current period transactions of $7.0 million and $(5.6) million during the 2014 three-month period and the 2013 three-month period, respectively.

Midstream & Marketing total revenues increased $17.3 million in the 2014 three-month period principally reflecting higher natural gas revenues ($13.2 million), greater capacity management, natural gas storage and natural gas gathering total revenues ($11.4 million) and, to a lesser extent, higher Electric Generation revenues ($4.6 million). These increases were partially offset by lower retail power sales revenues ($8.4 million) on lower retail power volumes sold. The increase in natural gas revenues principally reflects higher wholesale and retail natural gas volumes sold while capacity management and storage revenues reflect higher prices for these services during the current-year period. The increase in natural gas gathering revenues principally reflects incremental revenues from the Auburn pipeline extension which was placed in service during the first quarter of Fiscal 2014. The Electric Generation revenue increase principally reflects higher electricity output at the Conemaugh and Hunlock Creek electricity generating stations. Midstream & Marketing cost of sales was $216.6 million in the 2014 three-month period compared to $222.5 million in the 2013 three-month period principally reflecting lower cost of sales associated with the lower retail power sales partially offset by higher cost of sales associated with the greater wholesale and retail marketing natural gas volumes sold.

Midstream & Marketing total margin increased $23.2 million (89.6%) in the 2014 three-month period principally reflecting higher capacity management, storage and natural gas gathering total margin ($11.7 million), an increase in retail natural gas marketing total margin ($10.6 million) and higher Electric Generation total margin ($2.0 million). During the three months ended June 30, 2014, Midstream & Marketing continued to benefit from its Marcellus Shale midstream assets resulting from locational basis differences for the transportation of natural gas and incremental margin from the Auburn pipeline extension. The increase in retail natural gas marketing total margin reflects higher unit margins and, to a lesser extent, greater volumes sold. The greater total margin from Electric Generation principally reflects the impact of higher output at the Hunlock Creek and Conemaugh generating units during the 2014 three-month period as well as higher per-unit margins at the Hunlock Creek natural gas-fired electricity generating facility, reflecting in large part lower natural gas feedstock costs, greater electricity output, and higher Electric Generation capacity revenues.

Midstream & Marketing operating income and income before income taxes in the 2014 three-month period were $19.1 million and $19.2 million higher, respectively, than the prior-year period reflecting the previously mentioned increase in total margin ($23.2 million) partially offset by slightly higher operating, administrative and depreciation expenses. The higher operating, administrative and depreciation expenses principally include greater expenses associated with the expanded natural gas gathering assets. Electric Generation operating expenses were about equal to the prior-year three-month period reflecting higher expenses associated with the increased production at the Hunlock Creek facility offset by lower maintenance expenses associated with our interest in the Conemaugh electricity generating station.

Interest Expense and Income Taxes. Our consolidated interest expense during the 2014 three-month period was $60.1 million, $0.9 million higher than during the 2013 three-month period. Our consolidated effective tax rate (as calculated as a percentage of pretax income (loss) excluding noncontrolling interests not subject to income taxes) for the three months ended June 30, 2014, was comparable to such effective income tax rate for the prior-year three-month period.

2014 nine-month period compared to the 2013 nine-month period

Net income (loss) attributable to UGI Corporation by Business Unit:

	Nine Months Ended June 30,									
	2014			2013			Variance - Favorable (Unfavorable)			
(Millions of dollars)	Amount	% of Total		Amount	% of Total		Amount		% Change	
AmeriGas Propane	$66.4	18.6	%	$53.2	18.2	%	$13.2		24.8	%
UGI International	66.6	18.7	%	97.3	33.3	%	(30.7	)	(31.6	)%
Gas Utility	123.5	34.6	%	95.1	32.5	%	28.4		29.9	%
Midstream & Marketing	107.9	30.2	%	45.6	15.6	%	62.3		136.6	%
Corporate & Other (a)	(7.4)	(2.1	)%	1.1	0.4	%	(8.5	)	N.M.	
Net income attributable to UGI Corporation	$357.0	100.0	%	$292.3	100.0	%	$64.7		22.1	%

N.M. — Variance is not meaningful.

(a) Includes net after-tax gains on commodity derivative instruments not associated with current-period transactions at Midstream & Marketing of $0.6 million and $4.7 million during the nine months ended June 30, 2014 and 2013, respectively. Also includes net after-tax (losses) on commodity derivative instruments not associated with current period transactions at AmeriGas Propane for commodity derivative instruments entered into beginning April 1, 2014 of $(0.6) million during the nine months ended June 30, 2014.

AmeriGas Propane:

For the nine months ended June 30,	2014		2013		Increase		
(Millions of dollars)							
Revenues	$3,152.7		$2,636.9		$515.8	19.6	%
Total margin (a)	$1,343.7		$1,269.5		$74.2	5.8	%
Operating and administrative expenses	$744.1		$731.9		$12.2	1.7	%
Partnership EBITDA (b)	$616.5		$557.1		$59.4	10.7	%
Operating income (b)	$471.7		$407.5		$64.2	15.8	%
Retail gallons sold (millions)	1,064.6		1,039.8		24.8	2.4	%
Degree days—% colder (warmer) than normal (c)	4.3	%	(4.1	)%	—	—	

(a) Total margin represents total revenues less total cost of sales. Total margin for the 2014 nine-month period excludes net pre-tax losses of $2.8 million on AmeriGas Propane unsettled commodity derivative instruments entered into beginning April 1, 2014, not associated with current-period transactions.

(b) Partnership EBITDA should not be considered as an alternative to net income (as an indicator of operating performance) and is not a measure of performance or financial condition under GAAP. Management uses Partnership EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 6 to condensed consolidated financial statements). Partnership EBITDA for the nine months ended June 30, 2013, includes transition expenses of $20.7 million associated with the integration of Heritage Propane.

(c)

Deviation from average heating degree-days for the 30-year period 1971-2000 based upon national weather statistics provided by NOAA for 335 airports in the United States, excluding Alaska.

Table of Contents

AmeriGas Propane’s retail gallons sold in the 2014 nine-month period increased 2.4% compared with the 2013 nine-month period. The increase in retail gallons sold reflects average temperatures based upon heating degree days that were 4.3% colder than normal and 8.7% colder than the prior-year period principally reflecting significantly colder winter weather in the eastern half of the United States. The effects on retail gallons sold of the colder winter weather, however, were muted by supply challenges in certain regions of the U.S. experienced during the heating season caused by prolonged periods of unusually cold winter weather. In order to ensure that customers in these regions were adequately supplied during these extreme weather conditions, the Partnership instituted supply allocation measures which limited total retail volumes sold and increased distribution costs per gallon.
Retail propane revenues increased $491.3 million during the 2014 nine-month period reflecting the effects of higher average retail selling prices ($435.7 million), largely the result of higher propane product costs, and the higher retail volumes sold ($55.6 million). Wholesale propane revenues increased $35.1 million during the 2014 nine-month period reflecting the effects of higher wholesale selling prices ($34.1 million) and higher wholesale volumes sold ($1.1 million). Average daily wholesale propane commodity prices during the 2014 nine-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 34% higher than such prices during the prior-year nine-month period. In addition, certain regions of the U.S. experienced an even greater increase in wholesale commodity prices due to supply constraints caused by industry-wide storage and transportation issues exacerbated by the unusually cold winter weather conditions. Total revenues from fee income and other ancillary sales and services in the 2014 nine-month period were lower than in the 2013 nine-month period. Total cost of sales during the 2014 nine-month period increased $441.6 million principally reflecting the effects of the higher average propane product costs ($413.7 million) and, to a lesser extent, the effects of the greater retail and wholesale volumes sold ($30.1 million).

Total margin increased $74.2 million in the 2014 nine-month period principally reflecting higher retail propane total margin ($81.5 million) partially offset by lower margin from ancillary sales and services. The increase in retail propane total margin reflects modestly higher average retail propane unit margins and the increase in retail volumes sold.

Partnership EBITDA in the 2014 nine-month period increased $59.4 million principally reflecting the higher total margin ($74.2 million) partially offset by slightly higher operating and administrative expenses ($12.2 million). Partnership operating and administrative expenses in the prior-year period include $20.7 million of Heritage Propane transition expenses. Excluding the effects of the Heritage Propane transition expenses in the prior year, Partnership operating and administrative expenses increased $32.9 million. The increase in operating and administrative expenses excluding the effects of the Heritage Propane transition expenses in the prior-year period reflects, among other things, higher distribution-related expenses associated with the higher retail volumes sold, higher distribution costs caused by the supply challenges in certain regions of the U.S. during the second quarter of Fiscal 2014, and higher uncollectible accounts expense ($11.2 million). These increases were partially offset by expense synergies from the integration of Heritage Propane which was completed in Fiscal 2013. Operating income increased $64.2 million in the 2014 nine-month period principally reflecting the higher total margin ($74.2 million) partially offset by the slightly higher operating and administrative expenses ($12.2 million).

UGI International:

For the nine months ended June 30,	2014	2013	Increase (decrease)	
(Millions of dollars)				
Revenues	$1,889.3	$1,780.2	$109.1	6.1 %
Total margin (a)	$540.9	$558.7	$(17.8)	(3.2)%
Operating and administrative expenses	$359.7	$340.3	$19.4	5.7 %
Operating income	$127.5	$160.5	$(33.0)	(20.6)%
Income before income taxes	$104.5	$137.8	$(33.3)	(24.2)%

Retail gallons sold (millions) (b)	465.1	474.9	(9.8)	(2.1)%
Antargaz degree days—% (warmer) colder than normal (c)	(13.7)%	5.2%	—	—
Flaga degree days—% (warmer) colder than normal (c)	(15.7)%	0.4%	—	—

(a) Total margin represents total revenues less total cost of sales.
(b) Excludes retail gallons from operations in China.
(c) Deviation from average heating degree days for the 30-year period 1981-2010 at locations in our Antargaz and Flaga service territories.

Based upon heating degree day data, temperatures during the 2014 nine-month period at our UGI International European LPG operations were significantly warmer than normal compared to temperatures in the prior-year nine-month period that were slightly colder than normal. Total retail gallons sold were slightly lower reflecting the effects of the significantly warmer 2014 nine-month period weather partially offset by incremental retail gallons from the BP Poland acquisition. During the 2014 nine-month period, the average wholesale commodity price for propane in northwest Europe was approximately 8% lower than in the prior-year period while the average wholesale commodity price for butane was approximately 2% lower than the prior-year period.

UGI International base-currency results are translated into U.S. dollars based upon exchange rates experienced during each of the reporting periods. The functional currency of a significant portion of our UGI International results is the euro. During the 2014 and 2013 nine-month periods, the average un-weighted translation rate was approximately $1.37 and $1.31 per euro, respectively. The difference in euro to U.S. dollar translation rates and, to a lesser extent, the difference in the British pound sterling to the U.S. dollar, did not have a material impact on net income attributable to UGI.

UGI International revenues were $109.1 million higher than the prior-year period notwithstanding the lower retail volumes sold principally reflecting greater total revenues at Flaga ($151.7 million) the result of the BP Poland acquisition and the currency conversion effects of the slightly stronger euro. This increase in revenues was partially offset by lower total revenues at Antargaz ($34.7 million) and, to a lesser extent, at AvantiGas principally on the lower LPG retail volumes sold partially offset by the currency conversion effects of the stronger euro and British pound sterling. Cost of sales increased to $1,348.4 million in the 2014 nine-month period from $1,221.5 million in the prior-year period as greater cost of sales at Flaga ($142.0 million), primarily reflecting retail and wholesale gallons associated with the BP Poland acquisition and the effects of the stronger euro, were partially offset by lower cost of sales at AvantiGas and Antargaz principally as a result of the lower retail LPG gallons sold partially offset by the currency conversion effects of the slightly stronger British pound sterling and euro.

Total UGI International margin decreased $17.8 million during the 2014 nine-month period reflecting lower total margin at Antargaz ($33.6 million) principally on the lower retail volumes sold partially offset by higher total margin at Flaga, due primarily to incremental margin associated with the BP Poland acquisition, and higher total margin at AvantiGas principally the result of higher average retail unit margins.

UGI International 2014 nine-month period operating income and income before income taxes were $33.0 million and $33.3 million, respectively, lower than the prior-year period. The decreases principally reflect the lower total margin ($17.8 million); increased operating, administrative and depreciation expenses at Flaga ($12.9 million), principally incremental expenses resulting from the BP Poland acquisition and to a lesser extent the currency conversion effects of the slightly stronger euro; and the currency conversion effects of the stronger euro and British pound sterling on Antargaz and AvantiGas operating, administrative and depreciation expenses.

Gas Utility:

For the nine months ended June 30,	2014	2013	Increase		
(Millions of dollars)					
Revenues	$880.0	$743.6	$136.4	18.3	%
Total margin (a)	$416.5	$370.9	$45.6	12.3	%
Operating and administrative expenses	$138.0	$134.5	$3.5	2.6	%
Operating income	$233.7	$189.7	$44.0	23.2	%
Income before income taxes	$207.1	161.6	$45.5	28.2	%
System throughput—bcf —					
Core market	75.1	65.4	9.7	14.8	%
Total	172.8	158.5	14.3	9.0	%
Degree days—% colder (warmer) than normal (b)	10.2 %	(1.2)%	—	—	

(a) Total margin represents total revenues less total cost of sales.
(b)

Deviation from average heating degree days for the 15-year period 1995-2009 based upon weather statistics provided by NOAA for airports located within Gas Utility's service territory.

Temperatures in the Gas Utility service territory in the 2014 nine-month period based upon heating degree days were 10.2% colder than normal and 11.6% colder than the prior-year nine-month period. Total distribution system throughput increased 14.3 bcf principally reflecting a 9.7 bcf (14.8%) increase in demand from Gas Utility's core market customers and, to a lesser extent, greater net large firm and interruptible delivery service volumes. Gas Utility system throughput to core-market customers was higher than last year principally reflecting the effects of the significantly colder weather and, to a lesser extent, customer growth due principally to conversions from other fuels prompted by sustained lower natural gas prices and high oil prices.

Gas Utility revenues increased $136.4 million during the 2014 nine-month period principally reflecting higher revenues from core market customers ($80.8 million), higher revenues from off-system sales ($40.0 million) and, to a much lesser extent, higher revenues from large firm delivery service customers on higher throughput ($10.3 million). The increase in core market revenues principally reflects the effects of the higher core market throughput. Gas Utility's cost of gas was $463.5 million in the 2014 nine-month period compared with $372.7 million in the prior-year period principally reflecting the effects of the greater retail core-market volumes sold ($45.9 million) and the effects of the higher off-system sales ($40.0 million).
Gas Utility total margin increased $45.6 million in the 2014 nine-month period principally reflecting higher core market total margin ($32.5 million) and greater large firm delivery service total margin ($9.9 million). The higher core market and large firm delivery service total margin reflects the effects of the colder weather and customer growth.

Gas Utility operating income and income before income taxes during the 2014 nine-month period were $44.0 million and $45.5 million higher than the prior year, respectively. The increase in Gas Utility operating income principally reflects the $45.6 million increase in total margin. Operating expenses were slightly higher than the prior-year nine-month period as greater 2014 nine-month period uncollectible accounts expense was offset principally by lower distribution system maintenance expenses and lower pension and benefit expenses. The increase in Gas Utility income before income taxes reflects the greater operating income ($44.0 million) and lower interest expense principally reflecting lower average interest rates.

Midstream & Marketing:

For the nine months ended June 30,	2014	2013	Increase		
(Millions of dollars)					
Revenues (a)	$1,160.3	$810.9	$349.4	43.1	%
Total margin (b)	$251.6	$134.0	$117.6	87.8	%
Operating and administrative expenses	$50.7	$43.3	$7.4	17.1	%
Operating income	$183.7	$77.9	$105.8	135.8	%
Income before income taxes	$181.2	$75.5	$105.7	140.0	%

(a) Amounts are net of intercompany revenues between Midstream & Marketing's Energy Services and Electric Generation segments.

(b) Total margin represents total revenues less total cost of sales. Amounts exclude net pre-tax gains from changes in the fair values of Midstream & Marketing's unsettled commodity derivative instruments and settled commodity instruments not associated with current period transactions of $1.0 million and $8.1 million during the 2014 nine-month period and the 2013 nine-month period, respectively.

Midstream & Marketing total revenues increased $349.4 million in the 2014 nine-month period principally reflecting higher natural gas revenues ($262.5 million) principally from greater natural gas volumes and, to a much lesser extent, higher capacity management ($56.1 million), peaking ($26.2 million) and Electric Generation revenues. The increase in natural gas revenues principally reflects higher wholesale and retail natural gas volumes sold and higher natural gas prices during the 2014 nine-month period. The greater capacity management and peaking service revenues principally reflect higher demand for natural gas pipeline capacity at significantly higher prices caused by periods of extreme cold weather in the Northeast and Mid-Atlantic regions primarily during the months of January and February 2014. The increase in Electric Generation revenues reflects higher electricity production at the Hunlock Creek and Conemaugh electricity generating stations and higher sales prices. Midstream & Marketing revenues were higher also due to incremental revenues from the Auburn pipeline extension which was placed in service during the first quarter of Fiscal 2014. Midstream & Marketing cost of sales was $908.7 million in the 2014 nine-month period compared to $676.9 million in the 2013 nine-month period principally as the result of higher natural gas volumes and prices.

Midstream & Marketing total margin increased $117.6 million (87.8%) in the 2014 nine-month period principally reflecting higher capacity management and peaking service total margin ($73.3 million), higher retail natural gas total margin, and higher Electric Generation total margin ($16.2 million). To a much lesser extent, natural gas gathering total margin also increased reflecting incremental margin from the Auburn pipeline extension which was placed in service during the first quarter of Fiscal 2014. The significant increase in total margin from capacity management and peaking activities reflects higher demand for natural gas pipeline capacity at much higher prices as a result of periods of extreme cold weather primarily during January and February which resulted in significant locational basis price differences and increased demand for winter peaking services. The greater total margin from Electric Generation principally reflects the impact of higher unit margins at the Hunlock Creek natural gas-fired electricity generating facility due in large part to lower locally-sourced natural gas feedstock costs, greater electricity production, and higher Electric Generation capacity revenues. These increases in total margin were partially offset by lower total margin from retail power sales.

Midstream & Marketing operating income and income before income taxes during the 2014 nine-month period were $105.8 million and $105.7 million, respectively, higher than the prior-year period reflecting the previously mentioned significant increase in total margin ($117.6 million) partially offset by higher operating, administrative and depreciation expenses. The higher operating, administrative and depreciation expenses include, among other things, increased expenses associated with storage and natural gas gathering assets, higher uncollectible accounts expense and a $1.4 million charge relating to the write-off of certain deferred pipeline development costs. Electric Generation operating expenses in the 2014 nine-month period were slightly higher largely a result of higher operating costs principally from the increased production at the Hunlock Creek electricity generating facility offset in part by lower maintenance costs at the Conemaugh generating facility.

Interest Expense and Income Taxes. Our consolidated interest expense during the 2014 nine-month period was $178.9 million, a decrease of $1.9 million from the prior-year period principally reflecting lower Gas Utility interest expense. Our consolidated effective income tax rate for the nine months ended June 30, 2014, was higher than the prior-year period. The higher effective tax rate in the 2014 nine-month period reflects the effects of new tax legislation in France and, to a lesser extent, a higher proportion of pretax earnings from higher tax rate domestic business units. The new tax legislation in France, among other things, limits Antargaz' ability to deduct interest expense for income tax purposes on certain intercompany debt and increases the corporate surtax rate for a period of two years. Based upon our review of the new tax legislation, provisions of the new tax legislation associated with the deductibility of interest expense on certain intercompany debt at Antargaz applies retroactively to Fiscal 2013. During the three months ended December 31, 2013, the Company recorded income taxes of $5.7 million to reflect the retroactive effects of the new French tax legislation associated with the deductibility of interest expense on certain intercompany debt.

FINANCIAL CONDITION AND LIQUIDITY

Financial Condition and Liquidity

We depend on both internal and external sources of liquidity to provide funds for working capital and to fund capital requirements. Our short-term cash requirements not met by cash from operations are generally satisfied with borrowings under credit facilities and, in the case of Midstream & Marketing, also from a receivables purchase facility. Long-term cash requirements not met by cash from operations are generally met through issuance of long-term debt or equity securities. We believe that each of our business units has sufficient liquidity in the forms of cash and cash equivalents on hand; cash expected to be generated from operations; credit facility and receivables purchase facility borrowings; and the ability to obtain long-term financing to meet anticipated contractual and projected cash commitments. Issuances of debt and equity securities in the capital markets and additional credit facilities may not, however, be available to us on acceptable terms.

Our cash and cash equivalents totaled $438.4 million at June 30, 2014, compared with $389.3 million at September 30, 2013. Excluding cash and cash equivalents that reside at UGI's operating subsidiaries, at June 30, 2014 and September 30, 2013, UGI had $222.8 million and $171.6 million, respectively, of cash and cash equivalents.

Long-term Debt and Credit Facilities

The Company's debt outstanding at June 30, 2014, totaled $3,652.7 million (including current maturities of long-term debt of $78.4 million and bank loan borrowings of $96.5 million) compared to debt outstanding at September 30, 2013, of $3,837.3 million (including current maturities of long-term debt of $67.2 million and bank loan borrowings of $227.9 million). Total debt outstanding at June 30, 2014, consists of (1) $2,387.3 million of Partnership debt; (2) $611.0 million of UGI International debt; (3) $642.0 million of UGI Utilities debt; (4) $1.0 million of Midstream & Marketing debt; and (5) $11.4 million of other debt.

AmeriGas Partners. AmeriGas Partners' total debt at June 30, 2014, includes $2,250.8 million of AmeriGas Partners' Senior Notes, $92.5 million of AmeriGas OLP bank loan borrowings and $44.0 million of other long-term debt.

UGI International. UGI International's total debt at June 30, 2014, includes $468.3 million (€342 million) outstanding under Antargaz' Senior Facilities term loan, $52 million under Flaga's U.S. dollar-denominated term loan and a combined $80.9 million (€59.1 million) outstanding under Flaga's two term loans. Total UGI International debt outstanding at June 30, 2014, also includes combined borrowings of $4.0 million outstanding under all of Flaga's working capital facilities and $5.8 million (€4.3 million) of other long-term debt.

UGI Utilities. UGI Utilities' total debt at June 30, 2014, includes long-term debt comprising $450 million of Senior Notes and $192 million of Medium-Term Notes. In March 2014, UGI Utilities repaid $175 million outstanding under the UGI Utilities Term Loan Credit Agreement with proceeds from the issuance of $175 million of 4.98% Senior Notes due March 26, 2044. For further information on the 4.98% Senior Notes, see Note 14 to condensed consolidated financial statements.

Credit Facilities

Due to the seasonal nature of the Company's businesses, operating cash flows are generally strongest during the second and third fiscal quarters when customers pay for natural gas, LPG, electricity and other energy products consumed during the peak heating season months. Conversely, operating cash flows are generally at their lowest levels during the first and fourth fiscal quarters when the Company's investment in working capital, principally inventories and accounts receivable, is generally greatest. AmeriGas Propane and UGI Utilities primarily use their credit facilities to satisfy their seasonal operating cash flow needs. Energy Services historically has used its Receivables Facility to satisfy its operating cash flow needs. Energy Services also has a $240 million credit facility that it can use for working capital and general corporate purposes. Flaga principally uses borrowings under its credit agreements to satisfy its operating cash flow needs. Antargaz has generally funded its operating cash flow needs without using its revolving credit facilities and AvantiGas has satisfied its operating cash flow needs from cash on hand. Borrowings under the credit facilities and the Energy Services Receivables Facility are classified as bank loans on the Condensed Consolidated Balance Sheets.

AmeriGas Partners. In June 2014, AmeriGas OLP entered into an Amended and Restated Credit Agreement ("Amended and Restated Credit Agreement") with a group of banks which provides for borrowings up to $525 million (including a sublimit of $125 million for letters of credit). The Amended and Restated Credit Agreement amends and restates AmeriGas OLP's prior Credit Agreement entered into with a group of banks in June 2011, as amended from time to time. Among other things, the Amended and Restated Credit Agreement reduces the applicable margin on base rate and Eurodollar borrowings and reduces the facility fee. The aforementioned margins and facility fees are dependent upon AmeriGas Partners' ratio of debt to earnings before interest expense, income taxes, depreciation and amortization (as defined) which amount excludes, among other things, unrealized gains and losses on economic hedge transactions. The Amended and Restated Credit agreement expires on June 18, 2019. For further information on the Amended and Restated Credit Agreement, see Note 14 to the condensed consolidated financial statements.

UGI International. Under its Senior Facilities Agreement, Antargaz has a €40 million credit facility that expires in March 2016. Flaga has two principal working capital facilities (the "Flaga Credit Agreements") comprising (1) a €46 million multi-currency working capital facility that includes an uncommitted €6 million overdraft facility (the "Flaga Multi-Currency Working Capital Facility") and (2) a euro-denominated working capital facility that provides for borrowings and issuances of guarantees totaling €12 million (the "Euro Facility"). Both the Flaga Multi-Currency Working Capital Facility and the Euro Facility are currently scheduled to expire in September 2014. Flaga expects to extend these facilities prior to their expiration.

UGI Utilities. UGI Utilities has a revolving credit agreement (the "UGI Utilities Credit Agreement") with a group of banks providing for borrowings of up to $300 million (including a $100 million sublimit for letters of credit) that expires in October 2015.

Midstream & Marketing. Energy Services has an unsecured credit agreement ("Energy Services Credit Agreement") with a group of lenders providing for borrowings of up to $240 million (including a $50 million sublimit for letters of credit) that expires in June 2016. The Energy Services Credit Agreement can be used for general corporate purposes of Energy Services and its subsidiaries and to fund dividend payments provided that, after giving effect to such dividend payments, Energy Services maintains a specified ratio of Consolidated Total Indebtedness to EBITDA, each as defined in the Energy Services Credit Agreement.

Information about the Company's principal credit agreements as of and for the nine months ended June 30, 2014 and 2013, including the average daily and peak bank loan borrowings under the Company's principal credit agreements is presented in the table below. The Energy Services Receivables Facility is discussed further below and is excluded from the table. There were no borrowings under Antargaz' credit facility during the nine months ended June 30, 2014 or 2013.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

(Millions of dollars or euros)	As of June 30, 2014				For the nine months ended June 30, 2014	
	Total Capacity	Borrowings Outstanding	Letters of Credit and Guarantees Outstanding	Available Capacity	Average Borrowings	Peak Borrowings
AmeriGas Credit Agreement	$525.0	$92.5	$64.7	$367.8	$175.0	$320.0
Antargaz Credit Facility	€40.0	€0.0	€0.0	€40.0	N.A.	N.A.
Flaga Credit Agreements	€58.0	€0.0	€32.3	€25.7	€1.5	€3.6
UGI Utilities Credit Agreement	$300.0	$0.0	$2.0	$298.0	$30.4	$84.0
Energy Services Credit Agreement	$240.0	$0.0	$0.0	$240.0	$55.4	$114.0

	As of June 30, 2013				For the nine months ended June 30, 2013	
	Total Capacity	Borrowings Outstanding	Letters of Credit and Guarantees Outstanding	Available Capacity	Average Borrowings	Peak Borrowings
AmeriGas Credit Agreement	$525.0	$80.0	$54.1	$390.9	$106.6	$200.5
Antargaz Credit Facility	€40.0	€0.0	€0.0	€40.0	N.A.	N.A.
Flaga Credit Agreements	€58.0	€3.4	€18.8	€35.8	€13.4	€14.5
UGI Utilities Credit Agreement	$300.0	$0.0	$2.0	$298.0	$27.3	$79.0
Energy Services Credit Agreement	$240.0	$36.0	$0.0	$204.0	$45.9	$85.0

Energy Services has a receivables purchase facility (“Receivables Facility”) with an issuer of receivables-backed commercial paper that is currently scheduled to expire in October 2014. The Receivables Facility provides Energy Services with the ability to borrow up to $150 million of eligible receivables during the period November 1, 2013 to May 31, 2014, and up to $75 million of eligible receivables during the period June 1, 2014 to October 31, 2014. Energy Services uses the Receivables Facility to fund working capital, margin calls under commodity futures contracts, capital expenditures and dividends and for general corporate purposes. Energy Services intends to extend its Receivables Facility prior to its scheduled expiration.

Under the Receivables Facility, Energy Services transfers, on an ongoing basis and without recourse, its trade accounts receivable to its wholly owned, special purpose subsidiary, Energy Services Funding Corporation (“ESFC”), which is consolidated for financial statement purposes. ESFC, in turn, has sold, and subject to certain conditions, may from time to time sell, an undivided interest in some or all of the receivables to a major bank and, prior to October 1, 2013, a commercial paper conduit of a major bank. ESFC was created and has been structured to isolate its assets from creditors of Energy Services and its affiliates, including UGI. Trade receivables sold to the bank and, prior to October 1, 2013, the commercial paper conduit remain on the Company’s balance sheet and the Company reflects a liability equal to the amount advanced by the bank or the commercial paper conduit. The Company records interest expense on amounts owed to the bank or commercial paper conduit, as applicable.

During the nine months ended June 30, 2014 and 2013, Energy Services transferred trade receivables totaling $1,073.1 million and $766.1 million, respectively, to ESFC. During the nine months ended June 30, 2014 and 2013, ESFC sold an aggregate $196.0 million and $224.0 million, respectively, of undivided interests in its trade receivables to the bank or commercial paper conduit, as applicable. At June 30, 2014, the balance of ESFC receivables was $57.7 million and there were no amounts sold to the bank. At June 30, 2013, the outstanding balance of ESFC receivables was $58.2 million and there was $9.5 million sold to the commercial paper conduit. During the nine months ended

June 30, 2014 and 2013, peak amounts sold under the Receivables Facility were $70.0 million and $46.5 million, respectively, and average daily amounts sold were $19.2 million and $8.6 million, respectively.

UGI Common Stock Split

On July 29, 2014, UGI's Board of Directors approved a 3-for-2 common stock split. UGI will issue three shares for every two common shares outstanding. The new shares will be distributable September 5, 2014, to shareholders of record on August 22, 2014. Basic and diluted earnings per share and dividends declared per share for the three and nine month periods ended June 30, 2014 and 2013 have been reflected on a pre-split basis.

Dividends and Distributions

On July 29, 2014, UGI's Board of Directors approved an approximate 10.6% increase in the quarterly dividend rate on UGI Common Stock to $0.32625 per common share on a pre-split basis ($0.2175 per share after the previously-mentioned common stock split), or $1.305 per pre-split common share ($0.87 per share after the common stock split) on an annual basis. The new quarterly dividend is effective with the dividend payable on October 1, 2014, to shareholders of record on September 15, 2014. Previously, on April 29, 2014, UGI's Board of Directors approved an approximate 4.4% increase in the quarterly dividend rate on UGI Common Stock to $0.295 per pre-split common share (equal to $0.1967 per share after the common stock split) or $1.18 per pre-split common share (equal to $0.7867 per share after the common stock split) on an annual basis. This quarterly dividend rate was effective for the dividend paid on July 1, 2014, to shareholders of record on June 16, 2014.

On July 28, 2014, the General Partner's Board of Directors approved a quarterly distribution of $0.88 per Common Unit payable August 18, 2014, to unitholders of record on August 11, 2014. Previously, on April 28, 2014, the General Partner's Board of Directors approved an increase in the quarterly dividend rate on AmeriGas Partners Common Units to $0.88 per Common Unit, equal to an annual rate of $3.52 per Common Unit. The distribution reflects a 4.8% increase from the previous quarterly rate of $0.84. The new quarterly rate was effective with the distribution payable on May 19, 2014 to unitholders of record on May 9, 2014.

Cash Flows

Due to the seasonal nature of the Company's businesses, cash flows from operating activities are generally strongest during the second and third fiscal quarters when customers pay for natural gas, LPG, electricity and other energy products consumed during the peak heating season months. Conversely, operating cash flows are generally at their lowest levels during the fourth and first fiscal quarters when the Company's investment in working capital, principally inventories and accounts receivable, is generally greatest.

Operating Activities. Cash flow provided by operating activities was $858.1 million in the 2014 nine-month period compared to $686.4 million in the 2013 nine-month period. Cash flow from operating activities before changes in operating working capital was $921.9 million in the 2014 nine-month period compared to $807.7 million in the prior-year nine-month period. The increase in cash flow from operating activities before changes in operating working capital largely reflects the higher operating results during the 2014 nine-month period. Cash required to fund changes in operating working capital totaled $63.8 million in the 2014 nine-month period compared to $121.3 million in the prior-year nine-month period.

Investing Activities. Cash flow used by investing activities was $337.4 million in the 2014 nine-month period compared with $316.7 million in the prior-year period. Investing activity cash flow is principally affected by expenditures for property, plant and equipment; cash paid for acquisitions of businesses; changes in restricted cash balances; and proceeds from sales of assets. Cash payments for property, plant and equipment increased $33.9 million in the 2014 nine-month period as compared with the prior-year nine-month period principally reflecting the timing of cash payments for property, plant and equipment at Midstream & Marketing.

Financing Activities. Cash flow used by financing activities was $475.4 million in the 2014 nine-month period compared with $286.0 million in the prior-year period. Changes in cash flow from financing activities are primarily due to issuances and repayments of long-term debt; net bank loan borrowings; dividends and distributions on UGI Common Stock and AmeriGas Partners Common Units; and issuances of UGI and AmeriGas Partners equity instruments. In March 2014, UGI Utilities repaid $175 million outstanding under the UGI Utilities Term Loan Credit Agreement with proceeds from the issuance of $175 million of 4.98% Senior Notes due March 26, 2044. In addition, in May 2014, Antargaz repaid $52 million of maturing Senior Facilities term loan debt. During the 2014 nine-month period the Company used $21.4 million of cash to purchase UGI Common Stock pursuant to its share repurchase program authorized by the UGI Board of Directors in January 2014. The Board authorized a share repurchase program for up to 10 million shares of UGI Corporation Common Stock. The authorization permits the execution of the share repurchase program over a four-year period.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risk exposures are (1) commodity price risk; (2) interest rate risk; and (3) foreign currency exchange rate risk. Although we use derivative financial and commodity instruments to reduce market price risk associated with forecasted transactions, we do not use derivative financial and commodity instruments for speculative or trading purposes.

Commodity Price Risk

The risk associated with fluctuations in the prices the Partnership and our UGI International operations pay for LPG is principally a result of market forces reflecting changes in supply and demand for propane and other energy commodities. Their profitability is sensitive to changes in LPG supply costs. Increases in supply costs are generally passed on to customers. The Partnership and UGI International may not, however, always be able to pass through product cost increases fully or on a timely basis, particularly when product costs rise rapidly. In order to reduce the volatility of LPG market price risk, the Partnership uses contracts for the forward purchase or sale of propane, propane fixed-price supply agreements and over-the-counter derivative commodity instruments including price swap and option contracts. Our UGI International operations use over-the-counter derivative commodity instruments and may from time to time enter into other derivative contracts, similar to those used by the Partnership, to reduce market risk associated with a portion of their LPG purchases. Over-the-counter derivative commodity instruments used to hedge forecasted purchases of propane are generally settled at expiration of the contract. In addition, Antargaz hedges a portion of its future U.S. dollar-denominated LPG product purchases through the use of forward foreign exchange contracts as further described below.

Gas Utility's tariffs contain clauses that permit recovery of all of the prudently incurred costs of natural gas it sells to its customers, including the cost of financial instruments used to hedge purchased gas costs. The recovery clauses provide for periodic adjustments for the difference between the total amounts actually collected from customers through PGC rates and the recoverable costs incurred. Because of this ratemaking mechanism, there is limited commodity price risk associated with our Gas Utility operations. Gas Utility uses derivative financial instruments including natural gas futures and option contracts traded on the NYMEX to reduce volatility in the cost of gas it purchases for its retail core-market customers. The cost of these derivative financial instruments, net of any associated gains or losses, is included in Gas Utility's PGC recovery mechanism. At June 30, 2014, the fair values of Gas Utility’s natural gas futures and option contracts were net gains of $0.7 million.

Electric Utility's DS tariffs contain clauses which permit recovery of all prudently incurred power costs, including the cost of financial instruments used to hedge electricity costs, through the application of DS rates. Because of this ratemaking mechanism, there is limited power cost risk, including the cost of financial transmission rights (“FTRs”) and forward electricity purchase contracts, associated with our Electric Utility operations. At June 30, 2014, the fair values of Electric Utility’s electricity supply contracts were net gains of $0.8 million. At June 30, 2014, the fair values of Electric Utility’s FTRs were not material.

In addition, Gas Utility and Electric Utility from time to time enter into exchange-traded gasoline futures and swap contracts for a portion of gasoline volumes expected to be used in their operations. These gasoline futures and swap contracts are recorded at fair value with changes in fair value reflected in other income. The amount of unrealized gains on these contracts and associated volumes under contract at June 30, 2014, were not material.

In order to manage market price risk relating to substantially all of Midstream & Marketing’s fixed-price sales contracts for natural gas and electricity, Midstream & Marketing enters into NYMEX, Intercontinental Exchange and over-the-counter natural gas and electricity futures and natural gas basis swap contracts or enters into fixed-price supply arrangements. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to economically hedge a portion of its anticipated sales of electricity from its electricity generation facilities. Although Midstream & Marketing’s fixed-price supply arrangements mitigate most risks associated with its fixed-price sales contracts, should any of the suppliers under these arrangements fail to perform, increases, if any, in the cost of replacement natural gas or electricity would adversely impact Midstream & Marketing’s results. In order to reduce this risk of supplier nonperformance, Midstream & Marketing has diversified its purchases across a number of suppliers.

Midstream & Marketing purchases FTRs to economically hedge certain transmission costs that may be associated with its fixed-price electricity sales contracts. Midstream & Marketing from time to time also enters into New York Independent System Operator (“NYISO”) capacity swap contracts to economically hedge the locational basis differences for customers it serves on the NYISO electricity grid. Midstream & Marketing also uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later sale of natural gas or propane.

Midstream & Marketing has entered into fixed-price sales agreements for a portion of the electricity expected to be generated by its electric generation assets. In the event that these generation assets would not be able to produce all of the electricity needed to supply electricity under these agreements, Midstream & Marketing would be required to purchase electricity on the spot market or under contract with other electricity suppliers. Accordingly, increases in the cost of replacement power could negatively impact Midstream & Marketing's results.

The fair value of unsettled commodity price risk sensitive derivative instruments held at June 30, 2014 (excluding those Gas Utility and Electric Utility commodity derivative instruments which are refundable to or recoverable from customers) was a loss of $0.6 million. A hypothetical 10.0% adverse change in the market price of LPG, gasoline, natural gas, electricity and electricity transmission congestion charges would increase such loss by approximately $54.1 million at June 30, 2014.

Interest Rate Risk

We have both fixed-rate and variable-rate debt. Changes in interest rates impact the cash flows of variable-rate debt but generally do not impact their fair value. Conversely, changes in interest rates impact the fair value of fixed-rate debt but do not impact their cash flows.

Our variable-rate debt at June 30, 2014, includes our bank loan borrowings and Antargaz' and Flaga's variable-rate term loans. These debt agreements have interest rates that are generally indexed to short-term market interest rates. Antargaz and Flaga have effectively fixed the underlying euribor interest rates on their term loans through their scheduled maturity dates through the use of interest rate swaps. In addition, Flaga's $52.0 million U.S. dollar-denominated loan has been swapped from fixed-rate U.S. dollars to fixed-rate euro currency at issuance through cross currency swaps, removing interest rate risk and foreign currency exchange risk associated with the underlying interest and principal payments. At June 30, 2014, combined borrowings outstanding under these variable-rate debt agreements, excluding Antargaz' and Flaga's effectively fixed-rate debt, totaled $96.5 million.

Long-term debt associated with our domestic businesses is typically issued at fixed rates of interest based upon market rates for debt having similar terms and credit ratings. As these long-term debt issues mature, we may refinance such debt with new debt having interest rates reflecting then-current market conditions. In order to reduce interest rate risk associated with near- to medium-term forecasted issuances of fixed-rate debt, from time to time we enter into interest rate protection agreements ("IRPAs"). There were no unsettled IRPAs at June 30, 2014.

The fair value of unsettled interest rate risk sensitive derivative instruments held at June 30, 2014 (including pay-fixed, receive-variable interest rate swaps) was a loss of $25.2 million. A hypothetical 10% adverse change in the three-month euribor would result in a decrease in fair value of approximately $0.1 million.

Foreign Currency Exchange Rate Risk

Our primary currency exchange rate risk is associated with the U.S. dollar versus the euro. The U.S. dollar value of our foreign currency-denominated assets and liabilities will fluctuate with changes in the associated foreign currency exchange rates. From time to time we use derivative instruments to hedge portions of our net investments in foreign subsidiaries ("net investment hedges"). Gains or losses on net investment hedges remain in accumulated other comprehensive income until such foreign operations are liquidated. At June 30, 2014, there were no unsettled net investment hedges outstanding. With respect to our net investments in our UGI International operations, a 10% decline in the value of the associated foreign currencies versus the U.S. dollar, excluding the effects of any net investment hedges, would reduce their aggregate net book value at June 30, 2014, by approximately $102.1 million, which amount would be reflected in other comprehensive income.

In addition, in order to reduce volatility, Antargaz hedges a portion of its anticipated U.S. dollar-denominated LPG product purchases during the months of October through March through the use of forward foreign exchange contracts. The amount of U.S. dollar-denominated purchases of LPG associated with such contracts generally represents approximately 15% - 30% of estimated U.S. dollar-denominated purchases to occur during the heating-season months of October to March.

From time to time, the Company may enter into foreign currency exchange transactions to economically hedge the local-currency purchase price of anticipated foreign business acquisitions. These transactions do not qualify for hedge accounting treatment and any changes in fair value are recorded in other income, net.

The fair value of unsettled foreign currency exchange rate risk sensitive derivative instruments held at June 30, 2014, was a loss of $6.4 million. A hypothetical 10% adverse change in the value of the euro versus the U.S. dollar would result in a decrease in fair value of approximately $31.5 million.

Derivative Financial Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative financial instrument counterparties. Our derivative financial instrument counterparties principally comprise large energy companies and major U.S. and international financial institutions. We maintain credit policies with regard to our counterparties that we believe reduce overall credit risk. These policies include evaluating and monitoring our counterparties' financial condition, including their credit ratings, and entering into agreements with counterparties that govern credit limits.

Certain of our derivative instrument agreements call for the posting of collateral by the counterparty or by the Company in the forms of letters of credit, parental guarantees or cash. Additionally, our natural gas and electricity exchange-traded futures contracts generally require cash deposits in margin accounts. Declines in natural gas, LPG and electricity product costs can require our business units to post collateral with counterparties or make margin deposits to brokerage accounts. At June 30, 2014 and 2013, restricted cash in brokerage accounts totaled $5.9 million and $6.0 million, respectively.

Because a significant portion of our derivative instruments qualify as hedges under GAAP, we expect that changes in the fair value of derivative instruments used to manage commodity, currency or interest rate market risk would be substantially offset by gains or losses on the associated anticipated transactions.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company’s disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports filed under the Securities Exchange Act of 1934, as amended, is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC’s rules and forms, and (ii) accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Company’s management, with the participation of the Company’s Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company’s disclosure controls and procedures as of the end of the period covered by this Report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures, as of the end of the period covered by this Report, were effective at the reasonable assurance level.

(b) Change in Internal Control over Financial Reporting

No change in the Company’s internal control over financial reporting occurred during the Company’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Purported Class Action Lawsuits. Following the issuance of the FTC's administrative complaint described herein, more than 25 class action lawsuits have been filed in multiple jurisdictions against the Partnership/UGI Corporation and a competitor by certain of their direct and indirect customers. The class action lawsuits allege that the Partnership and its competitor colluded in 2008 to reduce the fill level and combined to persuade its common customer, Walmart Stores, Inc., to accept that fill reduction, resulting in increased cylinder costs to retailers and end-user customers in violation of federal and certain state antitrust laws. The claims seek treble damages, injunctive relief, attorneys' fees and costs on behalf of the putative classes. We believe these lawsuits will eventually be consolidated by a multidistrict litigation panel.

ITEM 1A. RISK FACTORS

In addition to the information presented in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended September 30, 2013, and Part II, "Item 1A. Risk Factors" in our Quarterly Reports on Form 10-Q for the fiscal quarters ended December 31, 2013 and March 31, 2014, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K and Quarterly Reports on Form 10-Q are not the only risks facing the Company. Other unknown or unpredictable factors could also have material adverse effects on future results.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) The following table sets forth information with respect to the Company's repurchases of its common stock during the quarter ended June 30, 2014.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
April 1, 2014 to April 30, 2014	20,403	$44.92	20,403	9.9 million
May 1, 2014 to May 31, 2014	213,059	$47.65	213,059	9.6 million
June 1, 2014 to June 30, 2014	119,959	$48.77	119,959	9.5 million
Total	353,421		353,421	

(1) Shares of UGI Corporation Common Stock are repurchased through a share repurchase program announced by the Company on January 30, 2014. The Board of Directors authorized the repurchase of up to 10 million shares of UGI Corporation Common Stock over a four-year period.

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

ITEM 6. EXHIBITS
The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and last date of the period for which it was filed, and the exhibit number in such filing):
Incorporation by Reference

Exhibit No.	Exhibit	Registrant	Filing	Exhibit
3.1	Articles of Amendment to the Amended and Restated Articles of Incorporation of UGI Corporation	UGI	Form 8-K (7/29/14)	3.1
10.1	Amended and Restated Credit Agreement dated as of June 18, 2014 by and among AmeriGas Propane, L.P., as Borrower, AmeriGas Propane, Inc., as a Guarantor, Wells Fargo Securities, LLC, as Sole Lead Arranger and Sole Book Manager, and the other financial institutions from time to time party thereto.	AmeriGas Partners, L.P.	Form 8-K (6/18/14)	10.1
31.1	Certification by the Chief Executive Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2014, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.2	Certification by the Chief Financial Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2014, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32	Certification by the Chief Executive Officer and the Chief Financial Officer relating to the Registrant’s Report on Form 10-Q for the quarter ended June 30, 2014, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	XBRL.Instance			
101.SCH	XBRL Taxonomy Extension Schema			
101.CAL	XBRL Taxonomy Extension Calculation Linkbase			
101.DEF	XBRL Taxonomy Extension Definition Linkbase			
101.LAB	XBRL Taxonomy Extension Labels Linkbase			
101.PRE	XBRL Taxonomy Extension Presentation Linkbase			

Table of Contents
UGI CORPORATION AND SUBSIDIARIES

SIGNATURES

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

	UGI Corporation (Registrant)
Date: August 7, 2014	By: /s/ Kirk R. Oliver Kirk R. Oliver Chief Financial Officer
Date: August 7, 2014	By: /s/ Davinder S. Athwal Davinder S. Athwal Vice President - Accounting and Financial Control and Chief Risk Officer

EXHIBIT INDEX

31.1	Certification by the Chief Executive Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2014, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by the Chief Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2014, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification by the Chief Executive Officer and the Chief Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2014, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL.Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase