Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2016

OR

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

For the transition period from ________ to ________

Commission file number 1-11071

UGI CORPORATION

(Exact name of registrant as specified in its charter)

Pennsylvania	**23-2668356**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
460 North Gulph Road, King of Prussia, PA	**19406**
(Address of principal executive offices)	**(Zip Code)**

(610) 337-1000
(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

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

At July 31, 2016, there were 173,246,168 shares of UGI Corporation Common Stock, without par value, outstanding.

UGI CORPORATION AND SUBSIDIARIES

TABLE OF CONTENTS

UGI CORPORATION AND SUBSIDIARIES

PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)
(Millions of dollars)

	June 30, 2016	September 30, 2015	June 30, 2015
ASSETS			
Current assets:			
Cash and cash equivalents	$ 909.2	$ 369.7	$ 385.9
Restricted cash	9.6	69.3	45.2
Accounts receivable (less allowances for doubtful accounts of $32.1, $29.7 and $40.3, respectively)	607.0	619.7	728.2
Accrued utility revenues	10.1	12.1	7.7
Inventories	184.2	239.9	208.7
Deferred income taxes	—	7.8	71.6
Utility regulatory assets	3.3	4.1	2.8
Derivative instruments	39.4	23.3	27.3
Prepaid expenses and other current assets	119.3	113.9	80.7
Total current assets	1,882.1	1,459.8	1,558.1
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $3,037.9, $2,835.0 and $2,773.6, respectively)	5,108.2	4,994.1	4,923.7
Goodwill	2,981.3	2,953.4	2,927.7
Intangible assets, net	587.9	610.1	628.5
Utility regulatory assets	342.0	300.1	251.4
Derivative instruments	10.6	16.3	15.6
Other assets	232.1	212.8	215.0
Total assets	$ 11,144.2	$ 10,546.6	$ 10,520.0
LIABILITIES AND EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 382.2	$ 258.0	$ 83.3
Short-term borrowings	144.0	189.9	68.0
Accounts payable	337.0	392.9	356.8
Derivative instruments	26.0	121.8	109.6
Other current liabilities	700.1	716.3	721.7
Total current liabilities	1,589.3	1,678.9	1,339.4
Long-term debt	3,774.7	3,441.8	3,628.3
Deferred income taxes	1,210.4	1,134.0	1,162.9
Deferred investment tax credits	3.3	3.6	3.7
Derivative instruments	13.2	31.2	25.7
Other noncurrent liabilities	716.6	684.7	624.4
Total liabilities	7,307.5	6,974.2	6,784.4
Commitments and contingencies (Note 9)			
Equity:			
UGI Corporation stockholders' equity:			
UGI Common Stock, without par value (authorized—450,000,000 shares; issued—173,875,641, 173,806,991 and 173,806,991 shares, respectively)	1,201.3	1,214.6	1,208.4
Retained earnings	1,925.8	1,636.9	1,685.3
Accumulated other comprehensive loss	(156.6)	(114.6)	(112.2)
Treasury stock, at cost	(21.3)	(44.9)	(33.0)
Total UGI Corporation stockholders' equity	2,949.2	2,692.0	2,748.5
Noncontrolling interests, principally in AmeriGas Partners	887.5	880.4	987.1
Total equity	3,836.7	3,572.4	3,735.6
Total liabilities and equity	$ 11,144.2	$ 10,546.6	$ 10,520.0

See accompanying notes to condensed consolidated financial statements.

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,	
	2016	2015	2016	2015
Revenues	$ 1,130.8	$ 1,148.1	$ 4,709.5	$ 5,608.3
Costs and expenses:				
Cost of sales (excluding depreciation shown below)	433.0	586.4	1,943.9	3,196.4
Operating and administrative expenses	445.5	419.8	1,390.6	1,322.1
Utility taxes other than income taxes	4.0	3.7	12.2	12.6
Depreciation	82.8	77.2	251.9	226.8
Amortization	15.3	15.3	47.5	44.7
Other operating income, net	(5.5)	(10.4)	(13.2)	(35.8)
	975.1	1,092.0	3,632.9	4,766.8
Operating income	155.7	56.1	1,076.6	841.5
Loss from equity investees	—	—	(0.1)	(1.1)
Loss on extinguishments of debt	(37.1)	—	(37.1)	—
Interest expense	(56.4)	(67.5)	(171.6)	(184.7)
Income (loss) before income taxes	62.2	(11.4)	867.8	655.7
Income tax expense	(33.6)	(4.5)	(263.3)	(189.2)
Net income (loss) including noncontrolling interests	28.6	(15.9)	604.5	466.5
Add net loss (deduct net income) attributable to noncontrolling interests, principally in AmeriGas Partners	32.1	25.5	(196.0)	(176.3)
Net income attributable to UGI Corporation	$ 60.7	$ 9.6	$ 408.5	$ 290.2
Earnings per common share attributable to UGI Corporation stockholders:				
Basic	$ 0.35	$ 0.06	$ 2.36	$ 1.68
Diluted	$ 0.34	$ 0.05	$ 2.33	$ 1.65
Weighted-average common shares outstanding (thousands):				
Basic	173,395	173,136	172,954	173,060
Diluted	175,974	175,580	175,260	175,665
Dividends declared per common share	$ 0.2375	$ 0.2275	$ 0.6925	$ 0.6625

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2016	2015	2016	2015
Net income (loss) including noncontrolling interests	$ 28.6	$ (15.9)	$ 604.5	$ 466.5
Other comprehensive income (loss):				
Net gains (losses) on derivative instruments (net of tax of $(3.4), $2.4, $10.9 and $(11.9), respectively)	7.8	(4.8)	(15.1)	23.1
Reclassifications of net losses (gains) on derivative instruments (net of tax of $(0.4), $(1.9), $5.5 and $(2.3), respectively)	0.6	0.5	(9.0)	0.7
Foreign currency adjustments (net of tax of $0, $(55.3), $0 and $(4.7), respectively)	(35.4)	(23.0)	(18.9)	(118.0)
Benefit plans (net of tax of $(0.3), $(0.1), $(0.7) and $(0.7), respectively)	0.3	0.4	1.0	1.4
Other comprehensive loss	(26.7)	(26.9)	(42.0)	(92.8)
Comprehensive income (loss) including noncontrolling interests	1.9	(42.8)	562.5	373.7
Add comprehensive loss (deduct comprehensive income) attributable to noncontrolling interests, principally in AmeriGas Partners	32.1	25.6	(196.0)	(174.5)
Comprehensive income (loss) attributable to UGI Corporation	$ 34.0	$ (17.2)	$ 366.5	$ 199.2

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Nine Months Ended June 30, 2016	Nine Months Ended June 30, 2015
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income including noncontrolling interests	$ 604.5	$ 466.5
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	299.4	271.5
Deferred income tax expense (benefit)	76.9	(39.9)
Provision for uncollectible accounts	18.3	26.2
Unrealized (gains) losses on derivative instruments	(133.0)	109.5
Loss on extinguishments of debt	37.1	—
Settlement of UGI Utilities interest rate protection agreements	(36.0)	—
Other, net	12.3	26.5
Net change in:		
Accounts receivable and accrued utility revenues	(15.6)	54.4
Inventories	54.6	211.0
Utility deferred fuel and power costs, net of changes in unsettled derivatives	(11.5)	59.4
Accounts payable	(67.8)	(171.2)
Other current assets	(8.9)	(3.7)
Other current liabilities	32.7	(42.1)
Net cash provided by operating activities	863.0	968.1
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(370.6)	(330.4)
Acquisitions of businesses, net of cash acquired	(60.3)	(428.2)
Decrease (increase) in restricted cash	59.7	(28.6)
Other, net	4.1	12.2
Net cash used by investing activities	(367.1)	(775.0)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(119.6)	(114.3)
Distributions on AmeriGas Partners publicly held Common Units	(192.3)	(185.3)
Issuances of debt	1,432.8	652.6
Repayments of debt	(1,027.0)	(406.4)
Decrease in short-term borrowings	(26.5)	(154.2)
Receivables Facility net (repayments) borrowings	(19.5)	12.5
Issuances of UGI Common Stock	13.0	10.3
Repurchases of UGI Common Stock	(24.7)	(17.3)
Other	12.4	(5.2)
Net cash provided (used) by financing activities	48.6	(207.3)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(5.0)	(19.4)
Cash and cash equivalents increase (decrease)	$ 539.5	$ (33.6)
CASH AND CASH EQUIVALENTS		
End of period	$ 909.2	$ 385.9
Beginning of period	369.7	419.5
Increase (decrease)	$ 539.5	$ (33.6)

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Nine Months Ended June 30, 2016	Nine Months Ended June 30, 2015
Common stock, without par value		
Balance, beginning of period	$ 1,214.6	$ 1,215.6
Common Stock issued in connection with employee and director plans (including (losses) on treasury stock transactions), net of tax withheld	(35.3)	(18.6)
Excess tax benefits realized on equity-based compensation	12.4	6.3
Equity-based compensation expense	9.6	11.7
Loss from acquisition of noncontrolling interests through business combination	—	(6.6)
Balance, end of period	$ 1,201.3	$ 1,208.4
Retained earnings		
Balance, beginning of period	$ 1,636.9	$ 1,509.4
Net income attributable to UGI Corporation	408.5	290.2
Cash dividends on Common Stock	(119.6)	(114.3)
Balance, end of period	$ 1,925.8	$ 1,685.3
Accumulated other comprehensive income (loss)		
Balance, beginning of period	$ (114.6)	$ (21.2)
Net (losses) gains on derivative instruments, net of tax	(15.1)	23.1
Reclassification of net (gains) losses on derivative instruments, net of tax	(9.0)	2.5
Benefit plans, net of tax	1.0	1.4
Foreign currency, net of tax	(18.9)	(118.0)
Balance, end of period	$ (156.6)	$ (112.2)
Treasury stock		
Balance, beginning of period	$ (44.9)	$ (44.7)
Common stock issued in connection with employee and director plans, net of tax withheld	72.9	33.2
Repurchases of Common Stock	(24.7)	(17.3)
Reacquired common stock - employee and director plans	(24.6)	(4.2)
Balance, end of period	$ (21.3)	$ (33.0)
Total UGI Corporation stockholders' equity	$ 2,949.2	$ 2,748.5
Noncontrolling interests		
Balance, beginning of period	$ 880.4	$ 1,004.1
Net income attributable to noncontrolling interests, principally in AmeriGas Partners	196.0	176.3
Reclassification of net gains on derivative instruments	—	(1.8)
Dividends and distributions	(192.3)	(185.8)
Change in noncontrolling interests as a result of business combination	—	(5.2)
Other	3.4	(0.5)
Balance, end of period	$ 887.5	$ 987.1
Total equity	$ 3,836.7	$ 3,735.6

See accompanying notes to condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

Note 1 — Nature of Operations

UGI Corporation ("UGI") is a holding company that, through subsidiaries and affiliates, distributes, stores, transports 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. We refer to UGI and its consolidated subsidiaries collectively as "the Company," "we" or "us."

We conduct a domestic 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"), which is 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, 2016, the General Partner held a 1% general partner interest and a 25.3% limited partner interest in AmeriGas Partners and held an effective 27.1% ownership interest in AmeriGas OLP. Our limited partnership interest in AmeriGas Partners comprises AmeriGas Partners Common Units ("Common Units"). The remaining 73.7% interest in AmeriGas Partners comprises Common Units held by the public. The General Partner also holds incentive distribution rights that entitle it to receive distributions from AmeriGas Partners in excess of its 1% general partner interest under certain circumstances as further described in Note 15 of our Annual Report on Form 10-K for the fiscal year ended September 30, 2015 (the "Company's 2015 Annual Report"). Incentive distributions received by the General Partner during the nine months ended June 30, 2016 and 2015 were $27.7 and $21.7, respectively.

Our wholly owned subsidiary, UGI Enterprises, Inc. ("Enterprises"), through subsidiaries, conducts (1) an LPG distribution business in France, Belgium, the Netherlands and Luxembourg ("UGI France"); (2) an LPG distribution business in central, northern and eastern Europe ("Flaga"); and (3) an LPG distribution business in the United Kingdom ("AvantiGas"). On May 29, 2015, UGI France SAS *(a Société par actions simplifiée)* ("France SAS") (formerly UGI Bordeaux Holding), an indirect wholly owned subsidiary of UGI, purchased all of the outstanding shares of Totalgaz SAS (the "Totalgaz Acquisition"), a retail distributor of LPG in France. The retail LPG distribution business of Totalgaz SAS and its subsidiaries is referred to herein as "Finagaz" and is included in our UGI France reportable segment (see Notes 14 and 15). The retail LPG distribution business of UGI France prior to the Totalgaz Acquisition is also referred to herein as "Antargaz." In March 2016, we sold our LPG distribution business located in the Nantong region of China. The sale did not have a material impact on our financial statements for the nine months ended June 30, 2016. We refer to our foreign LPG operations collectively as "UGI International."

Enterprises, through UGI Energy Services, LLC and its subsidiaries, conducts an energy marketing, midstream infrastructure, storage, natural gas gathering, natural gas production and energy services business primarily in the Mid-Atlantic and Northeast U.S. 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 is 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 ("HVAC").

Our natural gas distribution utility business ("Gas Utility") is 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." 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. Electric Utility is subject to regulation by the PUC. Gas Utility and Electric Utility are collectively referred to as "Utilities."

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

Note 2 — Summary of Significant Accounting Policies

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, 2015, 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 the Company's 2015 Annual Report. 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.

Earnings Per Common Share. Basic earnings per share attributable to UGI Corporation stockholders 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,	
	2016	2015	2016	2015
Denominator (thousands of shares):				
Weighted-average common shares outstanding - basic	173,395	173,136	172,954	173,060
Incremental shares issuable for stock options and awards	2,579	2,444	2,306	2,605
Weighted-average common shares outstanding - diluted	175,974	175,580	175,260	175,665

Derivative Instruments. Derivative instruments are reported on the Condensed Consolidated Balance Sheets at their fair values, unless the derivative instruments qualify for the normal purchase and normal sale ("NPNS") exception under GAAP. The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is designated and qualifies for hedge accounting.

Certain of our derivative instruments are designated and qualify as cash flow hedges and from time to time we also enter into net investment hedges. For cash flow hedges, changes in the fair values of the derivative instruments are recorded in accumulated other comprehensive income (loss) ("AOCI") or noncontrolling interests, to the extent effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. We discontinue cash flow hedge accounting if occurrence of the forecasted transaction is determined to be no longer probable. Hedge accounting is also discontinued for derivatives that cease to be highly effective. Gains and losses on net investment hedges that relate to our foreign operations are included in AOCI until such foreign net investment is sold or liquidated. Unrealized gains and losses on substantially all of the commodity derivative instruments used by Gas Utility and Electric Utility (for which NPNS has not been elected) are included in regulatory assets or liabilities because it is probable such gains or losses will be recoverable from, or refundable to, customers.

Effective October 1, 2014, UGI International determined on a prospective basis that it would not elect cash flow hedge accounting for its commodity derivative transactions and also de-designated its then-existing commodity derivative instruments accounted for as cash flow hedges. Also effective October 1, 2014, AmeriGas Propane de-designated its remaining commodity derivative instruments accounted for as cash flow hedges. Previously, AmeriGas Propane had discontinued cash flow hedge accounting for all commodity derivative instruments entered into beginning April 1, 2014. Midstream & Marketing has not applied cash flow hedge accounting for its commodity derivative instruments during any of the periods presented. Substantially all realized and unrealized gains and losses on commodity derivative instruments are recorded in cost of sales or revenues, as appropriate, on the Condensed Consolidated Statements of Income.

Cash flows from derivative instruments, other than net investment hedges and certain cross-currency swaps, if any, are included in cash flows from operating activities on the Condensed Consolidated Statements of Cash Flows. Cash flows from net investment hedges are included in cash flows from investing activities on the Condensed Consolidated Statements of Cash Flows. Cash flows from the interest portion of our cross-currency hedges are included in cash flow from operating activities while cash flows from the currency portion of such hedges are included in cash flow from financing activities.

For a more detailed description of the derivative instruments we use, our accounting for derivatives, our objectives for using them and other information, see Note 12.

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

Consolidated Effective Income Tax Rate. UGI's consolidated effective income tax rate, defined as total income tax (expense) or benefit as a percentage of income (loss) before income taxes, includes amounts associated with noncontrolling interests in the Partnership, which principally comprises AmeriGas Partners and AmeriGas OLP. AmeriGas Partners and AmeriGas OLP are not directly subject to federal income taxes. As a result, UGI's consolidated effective income tax rate is affected by the amount of income (loss) before income taxes attributable to noncontrolling interests in the Partnership not subject to income taxes.

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.

Correction of Prior Period Error in Other Comprehensive Income

During the three months ended June 30, 2015, the Company recorded an adjustment to decrease other comprehensive income related to prior periods by reducing the amount of net deferred tax assets that had been previously recognized for (1) foreign currency adjustments related to foreign subsidiaries whose undistributed earnings are considered indefinitely reinvested, and (2) foreign currency adjustments related to intercompany loans between a U.S. domiciled entity and its foreign branch that is considered disregarded for tax purposes and for which income taxes will not be payable. Accounting Standards Codification ("ASC") No. 740, "*Income Taxes,*" provides an exception to recording deferred tax attributes associated with these components of comprehensive income. Previously, the Company had incorrectly recorded deferred taxes on these currency adjustments. During the three months ended June 30, 2015, the Company evaluated the effects of the errors, both qualitatively and quantitatively, and concluded that they did not have a material impact on any prior period financial statement and recorded the cumulative effect of the error as of April 1, 2015. If the Company had corrected the error in all of the periods prior to April 1, 2015, other comprehensive loss for the three and nine months ended June 30, 2015, would have decreased by $57.8 and $10.7, respectively.

Note 3 — Accounting Changes

Adoption of New Accounting Standard

Presentation of Deferred Taxes. During the first quarter of Fiscal 2016, the Company adopted new accounting guidance regarding the classification of deferred taxes. The new guidance amends existing guidance to require that deferred income tax liabilities and assets be classified as noncurrent in a classified balance sheet, and eliminates the prior guidance which required an entity to separate deferred tax liabilities and assets into a current amount and a noncurrent amount in a classified balance sheet. We applied this guidance prospectively and, as a result, the September 30, 2015 and June 30, 2015 Condensed Consolidated Balance Sheets included herein have not been adjusted.

Accounting Standards Not Yet Adopted

Share-Based Payments. In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-09, "Improvements to Employee Share-Based Payment Accounting." This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The amendments in this ASU are effective for interim and annual periods beginning after December 15, 2016 (Fiscal 2018). Early adoption is permitted. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance.

Leases. In February 2016, the FASB issued ASU No. 2016-02, "Leases." This ASU amends existing guidance to require entities that lease assets to recognize the assets and liabilities for the rights and obligations created by those leases on the balance sheet.

(Currency in millions, except per share amounts)

The new guidance also requires additional disclosures about the amount, timing and uncertainty of cash flows from leases. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2018 (Fiscal 2020). Early adoption is permitted. Lessees must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance but anticipates an increase in the recognition of right-of-use assets and lease liabilities.

Debt Issuance Costs. In April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs." This ASU amends existing guidance to require the presentation of debt issuance costs in the balance sheet as a direct deduction from the carrying amount of the related debt liability instead of a deferred charge. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2015 (Fiscal 2017). Early adoption is permitted. Entities will apply the new guidance retrospectively to all periods presented. The Company expects to adopt the new guidance effective September 30, 2016. The adoption of the new guidance is not expected to have a material impact on the Company's financial statements.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers.” The guidance provided under this ASU, as amended, supersedes the revenue recognition requirements in ASC No. 605, “Revenue Recognition,” and most industry-specific guidance included in the ASC. 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 entity expects to be entitled in exchange for those goods or services. The new guidance is effective for the Company for interim and annual periods beginning after December 15, 2017 (Fiscal 2019) and allows for either full retrospective adoption or modified retrospective adoption. We have not yet selected a transition method and are currently evaluating the impact of adopting this guidance on our financial statements.

Note 4 — Inventories

Inventories comprise the following:

	June 30, 2016	September 30, 2015	June 30, 2015
Non-utility LPG and natural gas	$ 107.9	$ 140.7	$ 124.6
Gas Utility natural gas	13.5	37.5	19.2
Materials, supplies and other	62.8	61.7	64.9
Total inventories	$ 184.2	$ 239.9	$ 208.7

At June 30, 2016, UGI Utilities was a party to two principal storage contract administrative agreements (“SCAAs”) having terms of 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 terms 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 for which UGI Utilities has the rights), are included in the caption “Gas Utility natural gas” in the table above.

As of June 30, 2016, UGI Utilities had SCAAs with Energy Services and a non-affiliate. The carrying value of gas storage inventories released under the SCAAs with the non-affiliate at June 30, 2016, September 30, 2015 and June 30, 2015, comprising 1.8 billion cubic feet (“bcf”), 4.0 bcf and 1.9 bcf of natural gas, was $3.3, $9.8 and $4.5, respectively.

UGI CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

Note 5 — Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	June 30, 2016	September 30, 2015	June 30, 2015
Goodwill (not subject to amortization)	$ 2,981.3	$ 2,953.4	$ 2,927.7
Intangible assets:			
Customer relationships, noncompete agreements and other	$ 778.1	$ 761.1	$ 761.9
Accumulated amortization	(321.3)	(282.4)	(268.4)
Intangible assets, net (definite-lived)	456.8	478.7	493.5
Trademarks and tradenames (indefinite-lived)	131.1	131.4	135.0
Total intangible assets, net	$ 587.9	$ 610.1	$ 628.5

The changes in goodwill and intangible assets are primarily due to acquisitions and the effects of currency translation. Amortization expense of intangible assets was $13.4 and $41.4 for the three and nine months ended June 30, 2016, respectively. Amortization expense of intangible assets was $13.1 and $38.1 for the three and nine months ended June 30, 2015, respectively. Amortization expense included in cost of sales on the Condensed Consolidated Statements of Income is not material. The estimated aggregate amortization expense of intangible assets for the remainder of Fiscal 2016 and for the next four fiscal years is as follows: remainder of Fiscal 2016 — $12.3; Fiscal 2017 — $47.3; Fiscal 2018 — $45.8; Fiscal 2019 — $44.1; Fiscal 2020 — $42.8.

Note 6 — 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 9 in the Company's 2015 Annual Report. UGI Utilities currently 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, 2016	September 30, 2015	June 30, 2015
Regulatory assets:			
Income taxes recoverable	$ 119.6	$ 115.9	$ 111.8
Underfunded pension and postretirement plans	133.4	140.8	103.2
Environmental costs (a)	60.7	20.0	14.5
Removal costs, net	22.4	21.2	19.6
Other	9.2	6.3	5.1
Total regulatory assets	$ 345.3	$ 304.2	$ 254.2
Regulatory liabilities (b):			
Postretirement benefits	$ 19.7	$ 20.0	$ 19.6
Deferred fuel and power refunds	34.4	36.6	45.6
State tax benefits—distribution system repairs	14.6	13.3	10.9
Other	1.2	1.1	1.4
Total regulatory liabilities	$ 69.9	$ 71.0	$ 77.5

(a) Environmental costs at June 30, 2016, include amounts probable of recovery recorded in conjunction with UGI Gas' Consent Order and Agreement with the Pennsylvania Department of Environmental Protection (see Note 9).
(b) Regulatory liabilities are recorded in other current and other noncurrent liabilities on the Condensed Consolidated Balance Sheets.

Deferred fuel and power refunds. Gas Utility's and Electric Utility's tariffs contain clauses that 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") tariffs 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 overcollections are classified as a regulatory liability.

Gas Utility uses derivative instruments to reduce volatility in the cost of gas it purchases for firm- residential, commercial and industrial ("retail core-market") customers. Realized and unrealized gains or losses on natural gas derivative instruments are included in deferred fuel costs or refunds. Net unrealized gains (losses) on such contracts at June 30, 2016, September 30, 2015 and June 30, 2015 were $5.5, $(3.3) and $(0.7), respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. For contracts entered into prior to March 1, 2015, we did not elect the NPNS exception under GAAP, and as a result, we recognize the fair value of these contracts on the balance sheet with an associated adjustment to regulatory assets or liabilities because Electric Utility is entitled to fully recover its DS costs. At September 30, 2015 and June 30, 2015, the fair values of Electric Utility's electricity supply contracts not subject to NPNS were (losses) of $(0.5) and $(1.4), respectively. These amounts are reflected in current derivative instrument liabilities on the Condensed Consolidated Balance Sheets with equal and offsetting amounts reflected in deferred fuel and power refunds in the table above. At June 30, 2016, all Electric Utility forward electricity purchase contracts were subject to the NPNS exception (see Note 12).

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 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, 2016, September 30, 2015, and June 30, 2015, were not material.

Preliminary Stage Information Technology Costs. During the second quarter of Fiscal 2016, we determined that certain preliminary project stage costs associated with an ongoing information technology project at UGI Utilities were probable of future recovery in rates in accordance with GAAP related to regulated entities. As a result, during the second quarter of Fiscal 2016, we capitalized $5.8 of such project costs ($5.4 of which had been expensed prior to Fiscal 2016) and recorded associated increases to utility property, plant and equipment ($2.7) and regulatory assets ($3.1). Subsequently, we continue to capitalize such preliminary stage project costs in accordance with GAAP related to regulated entities.

UGI Gas Base Rate Filing. On January 19, 2016, UGI Utilities filed a rate request with the PUC to increase UGI Gas's annual base operating revenues for residential, commercial and industrial customers by $58.6. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. UGI Utilities requested that the new gas rates become effective March 19, 2016. The PUC entered an Order dated February 11, 2016, suspending the effective date for the rate increase to no later than October 19, 2016 to allow for investigation and public hearings. On June 30, 2016, a Joint Petition for Approval of Settlement of all issues supported by all active parties was filed with the PUC. Under the terms of the Joint Petition, UGI Utilities will be permitted, effective October 19, 2016, to increase UGI Gas' annual base distribution rates by $27.0. The Joint Petition is subject to receipt of a recommended decision by a PUC administrative law judge and an order of the PUC approving the settlement. The Company cannot predict the ultimate outcome of the rate case review process.

Distribution System Improvement Charge. On April 14, 2012, legislation became effective enabling gas and electric utilities in Pennsylvania, under certain circumstances, to recover the cost of eligible capital investment in distribution system infrastructure improvement projects between base rate cases. The charge enabled by the legislation is known as a distribution system improvement charge ("DSIC"). The primary benefit to a company from a DSIC charge is the elimination of regulatory lag, or delayed rate recognition, that occurs under traditional ratemaking relating to qualifying capital expenditures. To be eligible for a DSIC, a utility must have filed a general rate filing within five years of its petition seeking permission to include a DSIC in its tariff, and not exceed certain earnings tests. Absent PUC permission, the DSIC is capped at five percent of the amount billed to customers. PNG and CPG received PUC approval on a DSIC tariff, initially set at zero, in 2014, while UGI Gas had not had a general rate filing within the required time period to be eligible. PNG and CPG began charging a DSIC at a rate other than zero beginning on April 1, 2015 and April 1, 2016, respectively. In March 2016, PNG and CPG filed petitions, seeking approval to increase the maximum allowable DSIC from five percent to ten percent of billed distribution revenues. Also in March 2016, UGI Gas sought PUC approval to initiate a DSIC effective November 2017. To date, no action has been taken by the PUC on any of these petitions. The

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

Company cannot predict the timing or outcome of these petitions. The impact of the DSIC charge at PNG and CPG did not have a material effect on Gas Utility results of operations.

Note 7 — Energy Services Accounts Receivable Securitization Facility

Energy Services has an accounts receivable securitization facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in October 2016. The Receivables Facility provides Energy Services with the ability to borrow up to $150 of eligible receivables during the period November through April and up to $75 of eligible receivables during the period May through October. Energy Services uses the Receivables Facility to fund working capital, margin calls under commodity futures contracts, capital expenditures, dividends and for general corporate purposes.

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. 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 remain on the Company's balance sheet and the Company reflects a liability equal to the amount advanced by the bank. The Company records interest expense on amounts owed to the bank. Energy Services continues to service, administer and collect trade receivables on behalf of the bank, as applicable.

During the nine months ended June 30, 2016 and 2015, Energy Services transferred trade receivables to ESFC totaling $615.3 and $873.4, respectively. During the nine months ended June 30, 2016 and 2015, ESFC sold an aggregate $167.5 and $272.5, respectively, of undivided interests in its trade receivables to the bank. At June 30, 2016, the outstanding balance of ESFC receivables was $40.4, and there were no amounts sold to the bank. At June 30, 2015, the outstanding balance of ESFC receivables was $42.9, of which $20.0 was sold to the bank. Amounts sold to the bank are reflected as short-term borrowings on the Condensed Consolidated Balance Sheets. Losses on sales of receivables to the bank during the three and nine months ended June 30, 2016 and 2015, which are included in interest expense on the Condensed Consolidated Statements of Income, were not material.

Note 8 — Debt

Flaga

In October 2015, Flaga entered into a €100.8 Credit Facility Agreement ("Flaga Credit Facility Agreement") with a bank. The Flaga Credit Facility Agreement includes a €25 multi-currency revolving credit facility, a €5 overdraft facility, a €25 guarantee facility and a €45.8 variable-rate term loan facility. Borrowings under the Flaga Credit Facility Agreement's €45.8 term loan facility were used to refinance its €19.1 term loan due October 2016 and its €26.7 term loan due August 2016. Concurrent with entering into the Flaga Credit Facility Agreement, Flaga terminated its then-existing €46 multi-currency working capital facility.

The Flaga Credit Facility Agreement revolving credit facility borrowings bear interest at market rates (generally one, three or six-month euribor rates) plus margins. The margins on revolving facility borrowings, which range from 1.45% to 3.65%, are based upon the actual amount borrowed and certain consolidated equity, return on assets and debt to EBITDA ratios, as defined in the Flaga Credit Facility Agreement. Facility fees on the unused amount of the revolving credit facility are 30% of the lowest applicable margin. The Flaga Credit Facility Agreement is scheduled to expire in October 2020.

The €45.8 term loan matures in October 2020. The €45.8 term bears interest at three-month euribor rates, plus a margin. The margin on such borrowings ranges from 0.40% to 1.80% and is based upon certain consolidated equity, return on assets and debt to EBITDA ratios, as defined within the Flaga Credit Facility Agreement. Flaga has entered into pay-fixed, receive-variable interest rate swaps that generally fix the underlying euribor rate on the term loan borrowings at 2.18% through September 2016 and 0.23% from October 2016 through October 2020. Because the cash flows associated with the refinancing of the then-existing term loans were with the same bank, such cash flows have been reflected "net" on the Condensed Consolidated Statement of Cash Flows.

(Currency in millions, except per share amounts)

Energy Services

In February 2016, Energy Services entered into a Second Amended and Restated Credit Agreement (the "Energy Services Credit Agreement"), as borrower, with a group of lenders providing for borrowings up to $240, including a $50 sublimit for letters of credit. Borrowings under the Energy Services Credit Agreement bear interest at either (i) the Alternate Base Rate plus a margin or (ii) a rate derived from LIBOR ("Adjusted LIBOR") plus a margin. The Alternate Base Rate (as defined in the Energy Services Credit Agreement) is the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, and (c) the Adjusted LIBOR plus 1%. The margin on such borrowings is currently 2.25%. The Energy Services Credit Agreement requires that Energy Services not exceed a ratio of total indebtedness to EBITDA, as defined, of 3.50 to 1.00, and maintain a minimum ratio of EBITDA to interest expense, as defined, of 3.50 to 1.00. The Energy Services Credit Agreement is scheduled to expire in March 2021.

UGI Utilities

In April 2016, UGI Utilities entered into a Note Purchase Agreement (the "2016 Note Purchase Agreement") which provides for the private placement of (1) $100 aggregate principal amount of 2.95% Senior Notes due June 30, 2026; (2) $200 aggregate principal amount of 4.12% Senior Notes due September 30, 2046; and (3) $100 aggregate principal amount of 4.12% Senior Notes due October 31, 2046 (collectively, the "Utilities Senior Notes"). On June 30 2016, UGI Utilities issued $100 aggregate principal amount of 2.95% Senior Notes pursuant to the 2016 Note Purchase Agreement. The net proceeds from the issuance of the 2.95% Senior Notes were used to repay short-term borrowings under UGI Utilities' Credit Agreement in early July 2016. The 4.12% Senior Notes due September 30, 2046 and the 4.12% Senior Notes due October 31, 2046 are expected to be issued in September 2016 and October 2016, respectively. The Utilities Senior Notes are unsecured and rank equally with UGI Utilities' existing outstanding senior debt. UGI Utilities expects to use the net proceeds from the issuance of the 4.12% Senior Notes to repay UGI Utilities' currently outstanding $175 principal amount of 5.75% Senior Notes due September 30, 2016 and for general corporate purposes. Because UGI Utilities has the intent and ability to refinance the 5.75% Senior Notes on a long-term basis, the 5.75% Senior Notes have been classified as long-term debt on the June 30, 2016, Condensed Consolidated Balance Sheet. The 2016 Note Purchase Agreement contains restrictive and financial covenants including a requirement that UGI Utilities not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.00.

AmeriGas Propane

On June 27, 2016, AmeriGas Partners issued $675 principal amount of 5.625% Senior Notes due May 2024 (the "5.625% Senior Notes") and $675 principal amount of 5.875% Senior Notes due August 2026 (the "5.875% Senior Notes") (collectively, the "AmeriGas Senior Notes"). The AmeriGas Senior Notes rank equally with AmeriGas Partners' existing outstanding senior notes.

On June 20, 2016, AmeriGas Partners announced cash tender offers to purchase all of AmeriGas Partners' 6.50% Senior Notes, 6.75% Senior Notes and 6.25% Senior Notes (collectively, the "Tendered Notes"). A portion of the proceeds from the issuance of the previously mentioned AmeriGas Senior Notes, net of underwriters' discounts and offering expenses, were used on June 27, 2016, to redeem Tendered Notes having an aggregate principal amount of $917.1, plus tender premiums and accrued and unpaid interest. The remaining net proceeds from the issuance of the AmeriGas Senior Notes were used in July, and will be used in August 2016, to redeem the senior notes not repaid on June 27, 2016 (as further described below) and for general corporate purposes.

The aggregate principal amounts of the Tendered Notes subject to the tender offers, the associated amounts repaid on June 27, 2016, and the remaining amounts outstanding as of June 30, 2016, are as follows:

Notes	Aggregate Principal Amounts	Amounts Repaid on June 27, 2016	Remaining Amounts Outstanding at June 30, 2016
6.50% Senior Notes due May 2021	$ 270.0	$ 203.5	$ 66.5
6.75% Senior Notes due May 2020	550.0	406.9	143.1
6.25% Senior Notes due August 2019	450.0	306.7	143.3
Total	$ 1,270.0	$ 917.1	$ 352.9

In June 2016, the Partnership recognized a loss of $37.1 associated with the senior notes repaid on June 27, 2016, pursuant to the tender offers, primarily comprising $29.7 of tender premiums and the write-off of $6.7 of debt issuance costs. The loss is reflected in “Loss on extinguishments of debt” on the Condensed Consolidated Statements of Income.

On June 27, 2016, AmeriGas Partners issued a notice of cash redemption for the remaining 6.50% Senior Notes, 6.75% Senior Notes, and 6.25% Senior Notes not previously tendered, plus call premiums and accrued and unpaid interest. The redemption date for the 6.75% Senior Notes and the 6.50% Senior Notes was July 27, 2016, and the redemption date for the 6.25% Senior Notes is August 22, 2016. These senior notes have been included in “Current maturities of long-term debt” on the June 30, 2016, Condensed Consolidated Balance Sheet. The Partnership expects to recognize a loss on extinguishment of debt of approximately $12 during the fourth quarter of Fiscal 2016 associated with these redemptions.

UGI France

In May 2015, in connection with entering into a new senior facilities agreement, Antargaz prepaid its term loan outstanding under its existing senior facilities agreement and concurrently settled associated pay-fixed, receive-variable interest rate swaps. As a result of this transaction, Antargaz recorded a pre-tax loss of $10.3 comprising a $9.0 loss on interest rate swaps and the write-off of $1.3 of debt issuance costs. These amounts are included in interest expense on the Condensed Consolidated Statements of Income for the three and nine months ended June 30, 2015. For further information on this transaction, see Note 6 in the Company’s 2015 Annual Report.

Note 9 — Commitments and Contingencies

Environmental Matters

UGI Utilities

From the late 1800s through the mid-1900s, UGI Utilities and its current and former subsidiaries owned and operated a number of manufactured gas plants (“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. 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 has also acquired two subsidiaries (CPG and PNG) which have similar histories of owning, and in some cases operating, MGPs in Pennsylvania.

UGI Utilities and its subsidiaries have entered into agreements with the Pennsylvania Department of Environmental Protection (“DEP”) to address the remediation of former MGPs in Pennsylvania. CPG is party to a Consent Order and Agreement (“CPG-COA”) with the DEP requiring CPG to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which 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, required 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, 2016 and 2015, our estimated accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $12.2 and $9.6, respectively. CPG and PNG have recorded associated regulatory assets for these costs because recovery of these costs from customers is probable (see Note 6).

In May 2016, UGI Gas executed a Consent Order and Agreement (“UGI Gas-COA”) with the DEP with an effective date of October 1, 2016. The UGI Gas-COA will terminate in September 2031 if not extended by the parties. The UGI Gas-COA requires UGI Gas to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which MGP related facilities were operated (“UGI Gas MGP Properties”). Under this agreement, required environmental expenditures related to the UGI Gas MGP Properties are capped at $2.5 in any calendar year. At June 30, 2016, our estimated accrued liabilities for environmental investigation and remediation costs related to the UGI Gas-COA totaled $43.8. UGI Gas has recorded associated regulatory assets for these costs because recovery of these costs from customers is probable (see Note 6).

We do not expect the costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to UGI Utilities' 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 receive ratemaking recognition of environmental investigation and remediation costs associated with their environmental sites. This ratemaking recognition balances the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites. UGI Gas has proposed a similar environmental cost tracking mechanism that will address the costs incurred under the UGI Gas-COA.

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. At June 30, 2016, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas MGP sites outside of Pennsylvania was material.

Other Matters

Purported Class Action Lawsuits. Between May and October of 2014, more than 35 purported class action lawsuits were 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, among other things, that the Partnership and its competitor colluded, beginning in 2008, to reduce the fill level of portable propane cylinders from 17 pounds to 15 pounds and combined to persuade their 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. On October 16, 2014, the United States Judicial Panel on Multidistrict Litigation transferred all of these purported class action cases to the Western Division of the United States District Court for the Western District of Missouri. In July 2015, the Court dismissed all claims brought by direct customers and all claims other than those for injunctive relief brought by indirect customers. The direct customers filed an appeal with the United States Court of Appeals for the Eighth Circuit, which is still pending. The indirect customers filed an amended complaint claiming injunctive relief and state law claims under Wisconsin, Maine and Vermont law. In January 2016, the District Court dismissed the remaining injunctive relief claims for the indirect purchasers. As a result, the only claims remaining with respect to indirect purchasers involve alleged violations of Wisconsin, Maine and Vermont state antitrust laws. On July 21, 2016, several new indirect purchaser plaintiffs filed an antitrust class action lawsuit against the Partnership in the Western District of Missouri. This lawsuit repeats the allegations and claims from the existing indirect purchaser complaints, includes several of the same plaintiffs and was filed by the same group of lawyers. 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 financial position, results of operations or cash flows.

Note 10 — Defined Benefit Pension and Other Postretirement Plans

In the U.S., we sponsor a 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 ("U.S. Pension Plan"). We also provide postretirement health care benefits to certain retirees and active employees and postretirement life insurance benefits to nearly all U.S. active and retired employees. In addition, UGI France employees are covered by certain defined benefit pension and postretirement plans.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

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

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended June 30,	2016	2015	2016	2015
Service cost	$ 2.6	$ 2.5	$ 0.2	$ 0.2
Interest cost	6.7	6.2	0.2	0.2
Expected return on assets	(8.0)	(7.9)	(0.2)	(0.2)
Amortization of:				
Prior service cost (benefit)	—	—	(0.1)	(0.2)
Actuarial loss	2.7	2.5	—	0.1
Net benefit cost	4.0	3.3	0.1	0.1
Change in associated regulatory liabilities	—	—	0.9	0.9
Net expense	$ 4.0	$ 3.3	$ 1.0	$ 1.0

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended June 30,	2016	2015	2016	2015
Service cost	$ 7.6	$ 7.4	$ 0.6	$ 0.5
Interest cost	19.9	18.8	0.7	0.6
Expected return on assets	(24.0)	(23.8)	(0.5)	(0.5)
Amortization of:				
Prior service cost (benefit)	0.2	0.2	(0.4)	(0.4)
Actuarial loss	8.1	7.5	—	0.1
Net benefit cost	11.8	10.1	0.4	0.3
Change in associated regulatory liabilities	—	—	2.6	2.8
Net expense	$ 11.8	$ 10.1	$ 3.0	$ 3.1

The U.S. Pension Plan’s assets are held in trust and consist principally of publicly traded, diversified equity and fixed income mutual funds and, to a much lesser extent, smallcap common stocks and UGI Common Stock. It is our general policy to fund amounts for U.S. Pension Plan benefits equal to at least the minimum required contribution set forth in applicable employee benefit laws. During the nine months ended June 30, 2016 and 2015, the Company made cash contributions to the U.S. Pension Plan of $7.4 and $8.4, respectively. The Company expects to make additional discretionary cash contributions of approximately $2.5 to the U.S. Pension Plan during the remainder of Fiscal 2016.

UGI Utilities has established a Voluntary Employees’ Beneficiary Association (“VEBA”) trust to pay retiree health care and life insurance benefits by depositing into the VEBA the annual amount of postretirement benefits costs, if any, determined under GAAP. The difference between such amount and amounts included in UGI Gas’ and Electric Utility’s rates is deferred for future recovery from, or refund to, ratepayers. There were no required contributions to the VEBA during the nine months ended June 30, 2016 and 2015.

We also sponsor unfunded and non-qualified supplemental executive defined benefit retirement plans. Net periodic costs associated with these plans for the three and nine months ended June 30, 2016 and 2015 were not material.

UGI CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

Note 11 — Fair Value Measurements

Recurring Fair Value Measurements

The following table presents on a gross basis our financial assets and liabilities including both current and noncurrent portions, that are measured at fair value on a recurring basis within the fair value hierarchy, as of June 30, 2016, September 30, 2015 and June 30, 2015:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
June 30, 2016:				
Derivative instruments:				
Assets:				
Commodity contracts	$ 39.9	$ 30.3	$ —	$ 70.2
Foreign currency contracts	$ —	$ 18.6	$ —	$ 18.6
Cross-currency swaps	$ —	$ 0.3	$ —	$ 0.3
Liabilities:				
Commodity contracts	$ (47.1)	$ (24.3)	$ —	$ (71.4)
Foreign currency contracts	$ —	$ (0.8)	$ —	$ (0.8)
Interest rate contracts	$ —	$ (3.8)	$ —	$ (3.8)
Non-qualified supplemental postretirement grantor trust investments (a)	$ 32.0	$ —	$ —	$ 32.0
September 30, 2015:				
Derivative instruments:				
Assets:				
Commodity contracts	$ 17.4	$ 11.6	$ —	$ 29.0
Foreign currency contracts	$ —	$ 29.1	$ —	$ 29.1
Cross-currency swaps	$ —	$ 0.4	$ —	$ 0.4
Liabilities:				
Commodity contracts	$ (70.0)	$ (99.0)	$ —	$ (169.0)
Foreign currency contracts	$ —	$ (0.1)	$ —	$ (0.1)
Interest rate contracts	$ —	$ (10.8)	$ —	$ (10.8)
Non-qualified supplemental postretirement grantor trust investments (a)	$ 30.3	$ —	$ —	$ 30.3
June 30, 2015:				
Derivative instruments:				
Assets:				
Commodity contracts	$ 13.6	$ 8.2	$ —	$ 21.8
Foreign currency contracts	$ —	$ 29.1	$ —	$ 29.1
Interest rate contracts	$ —	$ 1.0	$ —	$ 1.0
Cross-currency swaps	$ —	$ 8.2	$ —	$ 8.2
Liabilities:				
Commodity contracts	$ (58.6)	$ (94.0)	$ —	$ (152.6)
Foreign currency contracts	$ —	$ (0.1)	$ —	$ (0.1)
Interest rate contracts	$ —	$ (2.0)	$ —	$ (2.0)
Non-qualified supplemental postretirement grantor trust investments (a)	$ 31.8	$ —	$ —	$ 31.8

(a) Consists primarily of mutual fund investments held in grantor trusts associated with non-qualified supplemental retirement plans.

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 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 that 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, foreign currency contracts and cross-currency contracts are based upon third-party quotes or indicative values based on recent market transactions. The fair values of investments held in grantor trusts are derived from quoted market prices as substantially all of the investments in these trusts have active markets. 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, 2016, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $4,156.9 and $4,312.0, respectively. At June 30, 2015, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,711.6 and $3,887.0, 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 instruments, such as short-term investments and trade accounts receivable, could expose us to concentrations of credit risk. We limit 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 arising from concentrations of trade accounts receivable is limited because we have a large customer base that extends across many different U.S. markets and a number of foreign countries. For information regarding concentrations of credit risk associated with our derivative instruments, see Note 12. Our investment in a private equity partnership is measured at fair value on a non-recurring basis. Generally this measurement uses Level 3 fair value inputs because the investment does not have a readily available market value.

Note 12 — Derivative Instruments and Hedging Activities

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. Although our commodity derivative instruments extend over a number of years, a significant portion of our commodity derivative instruments economically hedge commodity price risk during the next twelve months.

Commodity Price Risk

In order to manage market price risk associated with the Partnership's fixed-price programs, 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. The Partnership from time to time enters into price swap and put option agreements to reduce the effects of short-term commodity price volatility. At June 30, 2016 and 2015, total volumes associated with LPG commodity derivative instruments totaled 406.4 million gallons and 405.9 million gallons, respectively. At June 30, 2016, the maximum period over which we are economically hedging our exposure to LPG commodity price risk is 39 months.

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 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, 2016 and 2015, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 13.4 million dekatherms and 13.1 million dekatherms, respectively. At June 30, 2016, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 15 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 because it is probable such gains or losses will be recoverable from, or refundable to, customers through the PGC recovery mechanism (see Note 6).

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. For such contracts entered into by Electric Utility prior to March 1, 2015, Electric Utility chose not to elect the NPNS exception under GAAP and the fair values of these contracts are reflected in current derivative instrument liabilities on the Condensed Consolidated Balance Sheets. Associated gains and losses on these forward contracts are recorded in regulatory assets and liabilities on the Condensed Consolidated Balance Sheets in accordance with GAAP because it is probable such gains or losses will be recoverable from, or refundable to, customers through the DS mechanism (see Note 6). Effective with Electric Utility forward electricity purchase contracts entered into beginning March 1, 2015, Electric Utility has elected the NPNS exception under GAAP and, as a result, the fair values of such contracts are not recognized on the balance sheet. At June 30, 2016, all of our Electric Utility's forward electricity purchase contracts were subject to the NPNS exception. At June 30, 2015, the volumes of Electric Utility's forward purchase contracts for which NPNS had not been elected was 494.5 million kilowatt hours.

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. Midstream & Marketing purchases FTRs to economically hedge electricity transmission congestion costs associated with its fixed-price electricity sales contracts and 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. Gains and losses on Electric Utility FTRs are recorded in regulatory assets or liabilities in accordance with GAAP because it is probable such gains or losses will be recoverable from, or refundable to, customers through the DS mechanism (see Note 6). At June 30, 2016 and 2015, the total volumes associated with FTRs and NYISO capacity contracts totaled 80.6 million kilowatt hours and 494.5 million kilowatt hours, respectively. At June 30, 2016, the maximum period over which we are economically hedging electricity congestion and locational basis differences is 11 months.

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 and forward contracts, Intercontinental Exchange ("ICE") natural gas basis swap contracts, and electricity futures and forward 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 electric generation facilities. In addition, Midstream & Marketing uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later near-term sale of natural gas or propane. Because it could no longer assert the NPNS exception under GAAP for new contracts entered into for the forward purchase of natural gas and pipeline transportation, beginning in the second quarter of Fiscal 2014 Energy Services began recording these contracts at fair value with changes in fair value reflected in cost of sales.

At June 30, 2016 and 2015, total volumes associated with Midstream & Marketing's natural gas futures, forward and pipeline contracts totaled 79.6 million dekatherms and 120.8 million dekatherms, respectively. At June 30, 2016 and 2015, total volumes associated with Midstream & Marketing's natural gas basis swap contracts totaled 106.3 million dekatherms and 63.9 million dekatherms, respectively. At June 30, 2016, the maximum period over which we are hedging our exposure to the variability in cash flows associated with natural gas commodity price risk is 53 months. At June 30, 2016 and 2015, total volumes associated with Midstream & Marketing's electricity long forward and futures contracts and electricity short forward and futures contracts totaled 558.0 million kilowatt hours and 344.7 million kilowatt hours, and 429.5 million kilowatt hours and 210.5 million kilowatt hours, respectively. At June 30, 2016, the maximum period over which we are hedging our exposure to the variability in cash flows associated with electricity commodity price risk (excluding Electric Utility) is 36 months for electricity call contracts and 36 months for electricity put contracts. At June 30, 2016, the volumes associated with Midstream & Marketing's natural gas storage and propane storage NYMEX contracts totaled 1.8 million dekatherms and there were no propane storage NYMEX contracts. At June 30, 2015, the volumes associated with Midstream & Marketing's natural gas storage and propane storage NYMEX contracts totaled 0.8 million dekatherms and 2.0 million gallons, respectively.

At June 30, 2016, there were no amounts remaining in AOCI related to commodity derivative hedges.

Interest Rate Risk

France SAS's and Flaga's long-term debt agreements have interest rates that are generally indexed to short-term market interest rates. France SAS and Flaga have each entered into pay-fixed, receive-variable interest rate swap agreements to hedge the underlying euribor rates of interest on their variable-rate term loans through April 2019 in the case of France SAS's swap agreements and, through the respective scheduled maturity dates in the case of Flaga's long-term debt agreements. The France SAS swaps were originally executed in Fiscal 2015, at which time such swaps were designated in a cash flow hedging relationship associated with €600 notional amount of term loan debt issued in conjunction with the Totalgaz Acquisition. In March 2016, France SAS amended the terms of its pay-fixed, receive-variable interest rate swap agreements associated with the €600 term loan debt to purchase a 0% floor that is identical to the 0% floor embedded in France SAS's term loan debt. In conjunction with the amendments, in March 2016 France SAS paid its interest rate swap counterparties €7.7, which amount substantially equaled the interest rate swaps' fair value. Concurrent with the amendments to the interest rate swaps, the swaps were simultaneously de-designated and re-designated as cash flow hedges of future anticipated interest payments associated with the €600 term loan debt. The amended swaps fix the underlying euribor rate on the €600 term loan at 0.18%. As of June 30, 2016 and 2015, the total notional amounts of variable-rate debt subject to interest rate swap agreements (excluding Flaga's cross-currency swap as described below) were €645.8 and €659.1, 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"). On March 31, 2016, concurrent with the pricing of the Senior Notes to be issued under the 2016 Note Purchase Agreement, UGI Utilities settled all of its then-existing IRPA contracts associated with such debt at a loss of $36.0. Because these IRPA contracts qualified for and were designated as cash flow hedges, the loss recognized in connection with the settled IRPAs has been recorded in AOCI and will be recognized in interest expense as the associated future interest expense impacts earnings. See Note 8 for additional information on the 2016 Note Purchase Agreement. At June 30, 2016 and 2015, we had no unsettled IRPAs.

We account for interest rate swaps and IRPAs as cash flow hedges. At June 30, 2016, 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 $3.3.

Foreign Currency Exchange Rate Risk

In order to reduce exposure to foreign exchange rate volatility related to our foreign LPG operations, we hedge a portion of their anticipated U.S. dollar-denominated LPG product purchases primarily during the heating-season months of October through March through the use of forward foreign currency exchange contracts. At June 30, 2016 and 2015, we were hedging a total of $316.8 and $227.9 of our foreign operations' anticipated U.S. dollar-denominated LPG purchases, respectively. At June 30, 2016, the maximum period over which we are hedging our exposure to the variability in cash flows associated with U.S. dollar-denominated purchases of LPG is 38 months. From time to time we also enter into forward foreign currency exchange contracts to reduce the volatility of the U.S. dollar value of a portion of our International Propane euro-denominated net investments. At June 30, 2016 and 2015, 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. At June 30, 2016, the amount of net gains associated with currency rate risk expected to be reclassified into earnings during the next twelve months based upon current fair values is $12.3.

Cross-Currency Swaps

From time to time, Flaga enters into cross-currency swaps to hedge its exposure to the variability in expected future cash flows associated with the foreign currency and interest rate risk of U.S. dollar-denominated debt. These cross-currency hedges include initial and final exchanges of principal from a fixed euro denomination to a fixed U.S. dollar-denominated amount, to be exchanged at a specified rate, which was determined by the market spot rate on the date of issuance. These cross-currency swaps also include interest rate swaps of a fixed foreign-denominated interest rate to a fixed U.S. dollar-denominated interest rate. We designate these cross-currency swaps as cash flow hedges. At June 30, 2016 and 2015, cross-currency swaps were hedging foreign currency risk associated with interest and principal payments on $59.1 and $52.0 of Flaga U.S. dollar-denominated debt, respectively.

At June 30, 2016, the amount of net losses associated with this cross-currency swap expected to be reclassified into earnings during the next twelve months is not material.

Derivative Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative instrument counterparties. Our derivative 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 commodity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2016 and 2015, restricted cash in brokerage accounts totaled $9.6 and $45.2, respectively. Although we have concentrations of credit risk associated with derivative instruments, the maximum amount of loss, based upon the gross fair values of the derivative instruments, we would incur if these counterparties failed to perform according to the terms of their contracts was not material at June 30, 2016. 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, 2016, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities (and cash collateral received and pledged) are presented net by counterparty on the Condensed Consolidated Balance Sheets if the right of offset exists. Our derivative 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 over-the-counter derivative counterparties, if any, is reflected in the table below to offset derivative liabilities. Cash collateral received by us from our over-the-counter derivative counterparties, if any, is reflected in the table below to offset derivative assets. Certain other accounts receivable and accounts payable balances recognized on the 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.

UGI CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

Fair Value of Derivative Instruments

The following table presents the Company’s derivative assets and liabilities, as well as the effects of offsetting, as of June 30, 2016 and 2015:

	June 30, 2016	June 30, 2015
Derivative assets:		
Derivatives designated as hedging instruments:		
Foreign currency contracts	$ 18.6	$ 29.1
Cross-currency contracts	0.3	8.2
Interest rate contracts	—	1.0
	18.9	38.3
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	5.7	1.9
Derivatives not designated as hedging instruments:		
Commodity contracts	64.5	19.9
Total derivative assets - gross	89.1	60.1
Gross amounts offset in the balance sheet	(36.8)	(17.2)
Cash collateral received	(2.3)	—
Total derivative assets - net	$ 50.0	$ 42.9
Derivative liabilities:		
Derivatives designated as hedging instruments:		
Foreign currency contracts	$ (0.8)	$ (0.1)
Interest rate contracts	(3.8)	(2.0)
	(4.6)	(2.1)
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	(0.6)	(4.8)
Derivatives not designated as hedging instruments:		
Commodity contracts	(70.8)	(147.8)
Total derivative liabilities - gross	(76.0)	(154.7)
Gross amounts offset in the balance sheet	36.8	17.2
Cash collateral pledged	—	2.2
Total derivative liabilities - net	$ (39.2)	$ (135.3)

(Currency in millions, except per share amounts)

Table of Contents

Effect of Derivative Instruments

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, 2016 and 2015:

Three Months Ended June 30,:

Cash Flow Hedges:	Gain (Loss) Recognized in AOCI 2016	Gain (Loss) Recognized in AOCI 2015	Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income 2016	Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income 2015	Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
Commodity contracts	$ —	$ —	$ —	$ 0.1	Cost of sales
Foreign currency contracts	11.5	(6.4)	0.2	0.4	Cost of sales
Cross-currency contracts	0.3	(1.5)	0.1	8.6	Interest expense/other operating income, net
Interest rate contracts	(0.6)	0.6	(1.3)	(11.5)	Interest expense
Total	$ 11.2	$ (7.3)	$ (1.0)	$ (2.4)	

Derivatives Not Designated as Hedging Instruments:	Gain (Loss) Recognized in Income 2016	Gain (Loss) Recognized in Income 2015	Location of Gain (Loss) Recognized in Income
Commodity contracts	$ 44.8	$ (23.5)	Cost of sales
Commodity contracts	0.1	0.3	Revenues
Commodity contracts	—	0.1	Operating expenses / other operating income, net
Total	$ 44.9	$ (23.1)	

Nine Months Ended June 30,:

Cash Flow Hedges:	Gain (Loss) Recognized in AOCI 2016	Gain (Loss) Recognized in AOCI 2015	Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income 2016	Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income 2015	Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
Commodity contracts	$ —	$ —	$ —	$ (2.2)	Cost of sales
Foreign currency contracts	6.2	26.0	17.4	9.6	Cost of sales
Cross-currency contracts	—	6.0	0.3	8.5	Interest expense/other operating income, net
Interest rate contracts	(32.2)	3.0	(3.2)	(18.9)	Interest expense
Total	$ (26.0)	$ 35.0	$ 14.5	$ (3.0)	

Derivatives Not Designated as Hedging Instruments:	Gain (Loss) Recognized in Income 2016	Gain (Loss) Recognized in Income 2015	Location of Gain (Loss) Recognized in Income
Commodity contracts	$ (7.4)	$ (328.3)	Cost of sales
Commodity contracts	1.9	(0.5)	Revenues
Commodity contracts	(0.1)	(0.4)	Operating expenses/other operating income, net
Total	$ (5.6)	$ (329.2)	

For the three months ended June 30, 2016, the amounts of derivative gains or losses representing ineffectiveness were not material. For the nine months ended June 30, 2016, the amounts of derivative gains or losses representing ineffectiveness were losses of $5.5, which are recorded in other operating income, net, on the Condensed Consolidated Statements of Income and are related to interest rate contracts at UGI France. For the three and nine months ended June 30, 2016, the amounts of gains or losses recognized in income as a result of excluding derivatives from ineffectiveness testing were not material. For the three and nine months ended June 30, 2015, the amounts of derivative gains or losses representing ineffectiveness, and the amounts of gains or losses recognized in income as a result of excluding derivatives from ineffectiveness testing, were not material.

(Currency in millions, except per share amounts)

In May 2015, the Company prepaid term loans outstanding under Antargaz' 2011 Senior Facilities Agreement. In conjunction with the prepayment, the Company also settled its associated pay-fixed, receive-variable interest rate swaps, and discontinued cash flow hedge accounting treatment for such swaps. During the three months ended June 30, 2015, the Company recorded a pre-tax loss of $9.0 associated with the discontinuance of cash flow hedge accounting for the swaps, which amount is included in interest expense on the Condensed Consolidated Statements of Income.

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, contracts that provide for the purchase and delivery, or sale, of energy products, 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, certain of these contracts qualify for NPNS 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.

Note 13 — Accumulated Other Comprehensive Income

The tables below present changes in AOCI during the three and nine months ended June 30, 2016 and 2015:

Three Months Ended June 30, 2016	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI - March 31, 2016	$ (19.7)	$ (21.3)	$ (88.9)	$ (129.9)
Other comprehensive income (loss) before reclassification adjustments (after-tax)	—	7.8	(35.4)	(27.6)
Amounts reclassified from AOCI:				
Reclassification adjustments (pre-tax)	0.6	1.0	—	1.6
Reclassification adjustments tax expense	(0.3)	(0.4)	—	(0.7)
Reclassification adjustments (after-tax)	0.3	0.6	—	0.9
Other comprehensive income (loss) attributable to UGI	0.3	8.4	(35.4)	(26.7)
AOCI - June 30, 2016	$ (19.4)	$ (12.9)	$ (124.3)	$ (156.6)

Three Months Ended June 30, 2015	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency (a)	Total
AOCI - March 31, 2015	$ (19.6)	$ 20.5	$ (86.3)	$ (85.4)
Other comprehensive loss before reclassification adjustments (after-tax)	—	(4.8)	(23.0)	(27.8)
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	0.5	2.4	—	2.9
Reclassification adjustments tax benefit	(0.1)	(1.9)	—	(2.0)
Reclassification adjustments (after-tax)	0.4	0.5	—	0.9
Other comprehensive income (loss)	0.4	(4.3)	(23.0)	(26.9)
Add other comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	0.1	—	0.1
Other comprehensive income (loss) attributable to UGI	0.4	(4.2)	(23.0)	(26.8)
AOCI - June 30, 2015	$ (19.2)	$ 16.3	$ (109.3)	$ (112.2)

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

Nine Months Ended June 30, 2016	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI - September 30, 2015	$ (20.4)	$ 11.2	$ (105.4)	$ (114.6)
Other comprehensive loss before reclassification adjustments (after-tax)	—	(15.1)	(18.9)	(34.0)
Amounts reclassified from AOCI:				
Reclassification adjustments (pre-tax)	1.7	(14.5)	—	(12.8)
Reclassification adjustments tax expense	(0.7)	5.5	—	4.8
Reclassification adjustments (after-tax)	1.0	(9.0)	—	(8.0)
Other comprehensive income (loss) attributable to UGI	1.0	(24.1)	(18.9)	(42.0)
AOCI - June 30, 2016	$ (19.4)	$ (12.9)	$ (124.3)	$ (156.6)

Nine Months Ended June 30, 2015	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency (a)	Total
AOCI - September 30, 2014	$ (20.6)	$ (9.3)	$ 8.7	$ (21.2)
Other comprehensive income (loss) before reclassification adjustments (after-tax)	—	23.1	(118.0)	(94.9)
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	2.1	3.0	—	5.1
Reclassification adjustments tax benefit	(0.7)	(2.3)	—	(3.0)
Reclassification adjustments (after-tax)	1.4	0.7	—	2.1
Other comprehensive income (loss)	1.4	23.8	(118.0)	(92.8)
Add other comprehensive loss attributable to noncontrolling interests, principally in AmeriGas Partners	—	1.8	—	1.8
Other comprehensive income (loss) attributable to UGI	1.4	25.6	(118.0)	(91.0)
AOCI - June 30, 2015	$ (19.2)	$ 16.3	$ (109.3)	$ (112.2)

(a) See Note 2 relating to correction of prior-period error in other comprehensive income.

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

Note 14 — Segment Information

Our operations comprise six reportable segments generally based upon products sold, geographic location and regulatory environment. As more fully described below, effective October 1, 2015, the composition of our UGI Utilities (formerly Gas Utility) and Energy Services reportable segments changed to include certain operating segments previously included in Corporate & Other. Our reportable segments comprise: (1) AmeriGas Propane; (2) an international LPG segment comprising UGI France; (3) an international LPG segment principally comprising Flaga and AvantiGas; (4) UGI Utilities; (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.”

As a result of changes in the composition of information reported to our chief operating decision maker (“CODM”) associated with our regulated utility operations, effective October 1, 2015, we began including our Electric Utility operating segment with our Gas Utility reportable segment collectively referred to as “UGI Utilities.” Also, as a result of changes in segment management and reporting for HVAC, effective October 1, 2015, we began including the HVAC operating segment within our Energy Services reportable segment. Previously, these two operating segments, neither of which met the quantitative thresholds for presentation as a reportable segment under GAAP, were included within “Corporate & Other” in our segment information. In accordance with GAAP, prior-period amounts have been restated to reflect these changes.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

The accounting policies of our reportable segments are the same as those described in Note 2, "Summary of Significant Accounting Policies," in the Company's 2015 Annual Report. We evaluate AmeriGas Propane's performance principally based upon the Partnership's earnings before interest expense, income taxes, depreciation and amortization as adjusted for the effects of gains and losses on commodity derivative instruments not associated with current-period transactions and other gains and losses that competitors do not necessarily have ("Partnership Adjusted EBITDA"). Although we use Partnership Adjusted 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 Adjusted 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 as adjusted for gains and losses on commodity derivative instruments not associated with current-period transactions. Net gains and losses on commodity derivative instruments not associated with current-period transactions are reflected in Corporate & Other because the Company's CODM does not consider such items when evaluating the financial performance of our reportable segments.

					Midstream & Marketing		UGI International		
Three Months Ended June 30, 2016	Total	Eliminations	AmeriGas Propane	UGI Utilities	Energy Services	Electric Generation	UGI France	Flaga & Other	Corporate & Other (b)
Revenues	$ 1,130.8	$ (20.0) (c)	$ 446.7	$ 140.3	$ 156.8	$ 11.7	$ 280.7	$ 114.8	$ (0.2)
Cost of sales	$ 433.0	$ (19.2) (c)	$ 170.8	$ 44.4	$ 121.7	$ 4.9	$ 117.9	$ 61.8	$ (69.3)
Segment profit:									
Operating income (loss)	$ 155.7	$ 0.1	$ 18.3	$ 29.8	$ 12.6	$ (1.3)	$ 24.7	$ 8.8	$ 62.7
Loss on extinguishments of debt	(37.1)	—	(37.1)	—	—	—	—	—	—
Interest expense	(56.4)	—	(40.9)	(9.1)	(0.4)	—	(4.9)	(0.9)	(0.2)
Income (loss) before income taxes	$ 62.2	$ 0.1	$ (59.7)	$ 20.7	$ 12.2	$ (1.3)	$ 19.8	$ 7.9	$ 62.5
Partnership Adjusted EBITDA (a)			$ 64.6						
Noncontrolling interests' net (loss) income	$ (32.1)	$ —	$ (52.4)	$ —	$ —	$ —	$ (0.1)	$ —	$ 20.4
Depreciation and amortization	$ 98.1	$ (0.1)	$ 46.4	$ 16.6	$ 4.2	$ 3.4	$ 21.6	$ 5.8	$ 0.2
Capital expenditures (including the effects of accruals)	$ 137.4	$ —	$ 18.7	$ 56.5	$ 34.5	$ 1.8	$ 19.6	$ 6.3	$ —

					Midstream & Marketing		UGI International		
Three Months Ended June 30, 2015 (d)	Total	Eliminations	AmeriGas Propane	UGI Utilities	Energy Services	Electric Generation	UGI France	Flaga & Other	Corporate & Other (b)
Revenues	$ 1,148.1	$ (27.0) (c)	$ 478.0	$ 143.5	$ 189.5	$ 16.2	$ 196.1	$ 150.7	$ 1.1
Cost of sales	$ 586.4	$ (26.4) (c)	$ 211.4	$ 53.7	$ 148.2	$ 7.7	$ 107.9	$ 101.8	$ (17.9)
Segment profit:									
Operating income	$ 56.1	$ —	$ 0.8	$ 20.2	$ 18.2	$ 1.3	$ (9.1)	$ 8.8	$ 15.9
Interest expense	(67.5)	—	(40.3)	(9.9)	(0.5)	—	(15.7) (e)	(0.9)	(0.2)
(Loss) income before income taxes	$ (11.4)	$ —	$ (39.5)	$ 10.3	$ 17.7	$ 1.3	$ (24.8)	$ 7.9	$ 15.7
Partnership Adjusted EBITDA (a)			$ 48.9						
Noncontrolling interests' net (loss) income	$ (25.5)	$ —	$ (36.1)	$ —	$ —	$ —	$ (0.2)	$ —	$ 10.8
Depreciation and amortization	$ 92.5	$ —	$ 48.0	$ 15.9	$ 3.9	$ 3.2	$ 15.2	$ 5.9	$ 0.4
Capital expenditures (including the effects of accruals)	$ 113.2	$ —	$ 20.7	$ 43.3	$ 27.6	$ 1.1	$ 17.2	$ 3.3	$ —

UGI CORPORATION AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

					Midstream & Marketing		UGI International		
Nine Months Ended June 30, 2016	Total	Eliminations	AmeriGas Propane	UGI Utilities	Energy Services	Electric Generation	UGI France	Flaga & Other	Corporate & Other (b)
Revenues	$ 4,709.5	$ (124.6) (c)	$ 1,918.3	$ 660.3	$ 657.3	$ 42.3	$ 1,136.1	$ 416.3	$ 3.5
Cost of sales	$ 1,943.9	$ (122.2) (c)	$ 712.2	$ 257.3	$ 459.0	$ 17.2	$ 507.7	$ 245.8	$ (133.1)
Segment profit:									
Operating income	$ 1,076.6	$ 0.2	$ 398.3	$ 192.6	$ 130.0	$ 2.0	$ 188.0	$ 42.1	$ 123.4
Loss from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Loss on extinguishments of debt	(37.1)	—	(37.1)	—	—	—	—	—	—
Interest expense	(171.6)	—	(122.7)	(27.9)	(1.7)	—	(16.1)	(2.7)	(0.5)
Income before income taxes	$ 867.8	$ 0.2	$ 238.5	$ 164.7	$ 128.3	$ 2.0	$ 171.8	$ 39.4	$ 122.9
Partnership Adjusted EBITDA (a)			$ 537.7						
Noncontrolling interests' net income	$ 196.0	$ —	$ 150.9	$ —	$ —	$ —	$ 0.1	$ —	$ 45.0
Depreciation and amortization	$ 299.4	$ (0.2)	$ 143.0	$ 50.3	$ 12.6	$ 10.1	$ 66.5	$ 16.4	$ 0.7
Capital expenditures (including the effects of accruals)	$ 384.8	$ —	$ 74.5	$ 166.1	$ 71.6	$ 3.4	$ 53.2	$ 16.0	$ —
As of June 30, 2016									
Total assets	$ 11,144.2	$ (82.6)	$ 4,406.6	$ 2,699.9	$ 720.9	$ 277.1	$ 2,386.8	$ 519.8	$ 215.7
Short-term borrowings	$ 144.0	$ —	$ 11.4	$ 130.0	$ —	$ —	$ 0.7	$ 1.9	$ —
Goodwill	$ 2,981.3	$ —	$ 1,978.2	$ 182.1	$ 11.5	$ —	$ 714.4	$ 95.1	$ —

					Midstream & Marketing		UGI International		
Nine Months Ended June 30, 2015 (d)	Total	Eliminations	AmeriGas Propane	UGI Utilities	Energy Services	Electric Generation	UGI France	Flaga & Other	Corporate & Other (b)
Revenues	$ 5,608.3	$ (209.4) (c)	$ 2,467.1	$ 931.4	$ 927.7	$ 57.5	$ 881.2	$ 548.2	$ 4.6
Cost of sales	$ 3,196.4	$ (207.4) (c)	$ 1,179.0	$ 475.1	$ 698.3	$ 25.1	$ 517.5	$ 397.7	$ 111.1
Segment profit:									
Operating income (loss)	$ 841.5	$ 0.1	$ 437.4	$ 238.5	$ 155.6	$ 8.6	$ 82.5	$ 35.4	$ (116.6)
Loss from equity investees	(1.1)	—	—	—	—	—	(1.1)	—	—
Interest expense	(184.7)	—	(122.4)	(31.2)	(1.6)	—	(26.2) (e)	(2.8)	(0.5)
Income (loss) before income taxes	$ 655.7	$ 0.1	$ 315.0	$ 207.3	$ 154.0	$ 8.6	$ 55.2	$ 32.6	$ (117.1)
Partnership EBITDA (a)			$ 579.5						
Noncontrolling interests' net income	$ 176.3	$ —	$ 211.6	$ —	$ —	$ —	$ 0.2	$ —	$ (35.5)
Depreciation and amortization	$ 271.5	$ —	$ 145.5	$ 47.0	$ 11.6	$ 9.2	$ 40.3	$ 17.2	$ 0.7
Capital expenditures (including the effects of accruals)	$ 328.1	$ —	$ 77.9	$ 139.6	$ 46.6	$ 10.0	$ 38.9	$ 15.1	$ —
As of June 30, 2015									
Total assets	$ 10,520.0	$ (121.8)	$ 4,202.6	$ 2,423.2	$ 660.6	$ 277.6	$ 2,377.9	$ 534.5	$ 165.4
Short-term borrowings	$ 68.0	$ —	$ 43.6	$ 2.7	$ 20.0	$ —	$ —	$ 1.7	$ —
Goodwill	$ 2,927.7	$ —	$ 1,954.1	$ 182.1	$ 11.9	$ —	$ 699.8	$ 79.8	$ —

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

(a) The following table provides a reconciliation of Partnership Adjusted EBITDA to AmeriGas Propane (loss) income before income taxes:

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2016	2015	2016	2015
Partnership Adjusted EBITDA	$ 64.6	$ 48.9	$ 537.7	$ 579.5
Depreciation and amortization	(46.4)	(48.0)	(143.0)	(145.5)
Interest expense	(40.9)	(40.3)	(122.7)	(122.4)
Loss on extinguishments of debt	(37.1)	—	(37.1)	—
Noncontrolling interests (i)	0.1	(0.1)	3.6	3.4
(Loss) income before income taxes	$ (59.7)	$ (39.5)	$ 238.5	$ 315.0

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

(b) Corporate & Other results principally comprise (1) net expenses of UGI's captive general liability insurance company, and (2) UGI Corporation's unallocated corporate and general expenses and interest income. In addition, Corporate & Other results also include the effects of net pre-tax gains and (losses) on commodity derivative instruments not associated with current-period transactions totaling $67.9 and $18.1 during the three months ended June 30, 2016 and 2015, respectively, and $133.0 and $(109.5) during the nine months ended June 30, 2016 and 2015, respectively. Corporate & Other assets principally comprise cash and short-term investments of UGI and its captive insurance company; UGI corporate headquarters' assets; and our investment in a private equity partnership.
(c) Represents the elimination of intersegment transactions principally among Midstream & Marketing, UGI Utilities and AmeriGas Propane.
(d) Certain amounts have been restated to reflect the current-year changes in our segment presentation as described above.
(e) UGI France interest expense includes pre-tax loss of $10.3 associated with an early extinguishment of debt (see Note 8).

Note 15 — Acquisition of Totalgaz

On May 29, 2015 (the "Acquisition Date"), UGI, through its wholly owned indirect subsidiary, France SAS, acquired all of the outstanding shares of Totalgaz SAS, a retail distributor of LPG in France. In November 2015, France SAS received €1.1 ($1.2) of cash as a result of the completion of the final working capital amount. The Totalgaz Acquisition nearly doubles our retail LPG distribution business in France and is consistent with our growth strategies, one of which is to grow our core business through acquisitions.

The Condensed Consolidated Balance Sheet at June 30, 2016, reflects the final allocation of the purchase price to the assets acquired and liabilities assumed for the Totalgaz Acquisition.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

The components of the Totalgaz purchase price allocation are as follows:

Assets acquired:		
Cash	$	86.8
Accounts receivable (a)		170.3
Prepaid expenses and other current assets		11.0
Property, plant and equipment		375.6
Intangible assets (b)		91.3
Other assets		21.4
Total assets acquired	$	756.4
Liabilities assumed:		
Accounts payable		109.2
Other current liabilities		103.5
Deferred income taxes		117.5
Other noncurrent liabilities		113.4
Total liabilities assumed	$	443.6
Goodwill		183.8
Net consideration transferred (including working capital adjustments)	$	496.6

(a) Approximates the gross contractual amounts of receivables acquired.
(b) Comprises $79.3 of customer relationships and $12.0 of tradenames.

The excess of the purchase price for the Totalgaz Acquisition over the fair values of the assets acquired and liabilities assumed has been reflected as goodwill, assigned to the UGI France reportable segment, and results principally from anticipated synergies and value creation resulting from the Company's combined LPG businesses in France. The goodwill is not deductible for income tax purposes.

The Company recognized $2.7 and $13.7 of direct transaction-related costs associated with the Totalgaz Acquisition during the three and nine months ended June 30, 2015, respectively, which are reflected primarily in operating and administrative expenses on the Condensed Consolidated Statements of Income.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Currency in millions, except per share amounts)

The following table presents unaudited pro forma revenues, net income attributable to UGI Corporation and earnings per share data for the three and nine months ended June 30, 2015 as if the Totalgaz Acquisition had occurred on October 1, 2014. The unaudited pro forma consolidated information reflects the historical results of Totalgaz SAS and its subsidiaries after giving effect to adjustments directly attributable to the transaction, including depreciation, amortization, interest expense, intercompany eliminations and related income tax effects. The unaudited pro forma net income also reflects the effects of the issuance of the €600 term loan under France SAS's 2015 Senior Facilities Agreement and the associated repayment of the term loan outstanding under Antargaz' 2011 Senior Facilities Agreement as if such transactions had occurred on October 1, 2014.

	Three Months Ended June 30, 2015		Nine Months Ended June 30, 2015	
	As Reported	Pro Forma Adjusted	As Reported	Pro Forma Adjusted
Revenues	$ 1,148.1	$ 1,204.2	$ 5,608.3	$ 5,983.0
Net income attributable to UGI Corporation	$ 9.6	$ 16.3	$ 290.2	$ 348.5
Earnings per common share attributable to UGI Corporation stockholders:				
Basic	$ 0.06	$ 0.09	$ 1.68	$ 2.01
Diluted	$ 0.05	$ 0.09	$ 1.65	$ 1.98

The unaudited pro forma consolidated information is not necessarily indicative of the results that would have occurred had the Totalgaz Acquisition occurred on the date indicated nor are they necessarily indicative of future operating results.

In connection with the Totalgaz Acquisition, the Company agreed with the French Competition Authority (the "FCA") to divest certain assets and investments of Totalgaz SAS and certain assets of Antargaz located in France no later than August 15, 2016. Following the closing of the Totalgaz Acquisition, two competitors in the French LPG distribution market challenged the decision of the FCA. The competitors' request for interim measures suspending the effectiveness of the agreed remedies was denied by the supreme administrative court (Conseil d'Etat). In July 2016, the Conseil d'Etat confirmed the decision of the FCA in part, but directed the FCA to conduct further analysis as to certain assets and to consider further remedies with respect to the assets that were previously identified for divestiture. Although we cannot predict the final results of this matter, we believe that the final outcome of the proceedings will not have a material effect on our financial position, results of operations or cash flows.

For additional information regarding the Totalgaz Acquisition, see Note 4 to the Company's 2015 Annual Report.

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 (the "Exchange Act"). 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 liquefied petroleum gases, 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 liquefied petroleum gases ("LPG"); (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) changes in 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 the Company's 2015 Annual Report, 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 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 the Company's results of operations for the three months ended June 30, 2016 ("2016 three-month period") with the three months ended June 30, 2015 ("2015 three-month period") and the nine months ended June 30, 2016 ("2016 nine-month period") with the nine months ended June 30, 2015 ("2015 nine-month period"). Our analyses of results of operations should be read in conjunction with the segment information included in Note 14 to the condensed consolidated financial statements. As a result of certain reporting changes associated with our Electric Utility and HVAC businesses, beginning in Fiscal 2016, we combined Electric Utility with our Gas Utility reportable segment under the reportable segment caption, "UGI Utilities." In addition, we combined UGI Enterprises' HVAC business with our Energy Services reportable segment. Previously, Electric Utility and HVAC, neither of which met the quantitative thresholds for presentation as a reportable segment under accounting principles generally accepted in the U.S. ("GAAP"), were included within "Corporate & Other" in our segment information. We have restated our prior-period segment information to conform to the current-period presentation.

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, excluding the effects of gains and losses on commodity derivative instruments not associated with current period transactions as further discussed below, are significantly higher in our first and second fiscal quarters.

UGI management uses “adjusted net income attributable to UGI” and “adjusted diluted earnings per share,” both of which are non-GAAP financial measures, when evaluating UGI’s overall performance. Adjusted net income attributable to UGI excludes (1) net after-tax gains and losses on commodity derivative instruments not associated with current-period transactions and (2) other significant discrete items that management believes affect the comparison of period-over-period results (as such items are further described below). Volatility in net income attributable to UGI as determined in accordance with GAAP can occur as a result of gains and losses on commodity derivative instruments not associated with current-period transactions. These gains and losses result principally from recording changes in unrealized gains and losses on unsettled commodity derivative instruments and, to a much lesser extent, certain realized gains and losses on settled commodity derivative instruments that are not associated with current-period transactions. Although our GAAP net income is affected by after-tax gains and losses on commodity derivative instruments not associated with current-period transactions, because these instruments economically hedge anticipated future purchases or sales of energy commodities, we expect that such gains and losses will be largely offset by gains or losses on the anticipated future transactions when such derivative contracts are settled and the associated energy commodity is purchased or sold. For further information, see “Non-GAAP Financial Measures” below.

Executive Overview

Three Months Ended June 30, 2016 Results

We recorded GAAP net income attributable to UGI Corporation for the 2016 three-month period of $60.7 million, equal to $0.34 per diluted share, compared to GAAP net income attributable to UGI Corporation for the 2015 three-month period of $9.6 million, equal to $0.05 per diluted share. Our 2016 three-month period results reflect the full-period operations of French LPG distributor Finagaz which we acquired on May 29, 2015. GAAP net income attributable to UGI in the 2016 three-month period includes after-tax gains on commodity derivative instruments not associated with current-period transactions of $29.6 million (equal to $0.16 per diluted share) compared to after-tax gains in the 2015 three-month period of $4.9 million (equal to $0.03 per diluted share). GAAP net income attributable to UGI in the 2016 and 2015 three-month periods also reflect acquisition and integration expenses associated with Finagaz which decreased GAAP net income attributable to UGI by $2.8 million (equal to $0.02 per diluted share) and $3.1 million (equal to $0.02 per diluted share), respectively. GAAP net income attributable to UGI Corporation in the 2016 three-month period also includes an after-tax loss on extinguishments of debt at AmeriGas Propane of $6.1 million (equal to $0.03 per diluted share) while GAAP net income in the 2015 three-month period includes an after-tax loss associated with an extinguishment of debt at Antargaz of $4.6 million (equal to $0.03 per diluted share).

Adjusted net income attributable to UGI for the 2016 three-month period was $40.0 million (equal to $0.23 per diluted share) compared to $12.4 million (equal to $0.07 per diluted share) in the 2015 three-month period. The significantly higher 2016 three-month period adjusted net income attributable to UGI principally reflects (1) a $24.2 million increase from UGI International (excluding the previously mentioned effects of Finagaz acquisition and integration expenses in both periods and the loss associated with an extinguishment of debt in the prior-year three-month period); (2) a $5.3 million increase from UGI Utilities; and (3) a $4.0 million increase from AmeriGas Propane (excluding the previously mentioned loss on extinguishments of debt in the 2016 three-month period). These increases were partially offset by a $4.9 million decrease from Midstream & Marketing. The significant increase from UGI International in the 2016 three-month period reflects, in large part, the full-period of the Finagaz operations, higher average retail LPG unit margins at our legacy UGI France business resulting in large part from lower LPG wholesale commodity costs, and the volume effects of significantly colder 2016 three-month period weather.

Nine Months Ended June 30, 2016 Results

We recorded GAAP net income attributable to UGI Corporation for the 2016 nine-month period of $408.5 million, equal to $2.33 per diluted share, compared to GAAP net income attributable to UGI Corporation for the 2015 nine-month period of $290.2 million, equal to $1.65 per diluted share. GAAP net income attributable to UGI in the 2016 nine-month period includes after-tax gains on commodity derivative instruments not associated with current-period transactions of $55.6 million (equal to $0.31 per diluted share) compared to after-tax losses in the 2015 nine-month period of $46.2 million (equal to $0.26 per diluted share). GAAP net income attributable to UGI in the 2016 and 2015 nine-month periods also reflect acquisition and integration expenses associated with Finagaz which decreased net income attributable to UGI by $9.6 million (equal to $0.05 per diluted share) and $10.9 million (equal to $0.06 per diluted share), respectively. GAAP net income attributable to UGI Corporation in the 2016 nine-month period also includes an after-tax loss on extinguishments of debt at AmeriGas Propane of $6.1 million (equal to $0.03 per diluted share) while GAAP net income in the 2015 nine-month period includes an after-tax loss associated with an extinguishment of debt at Antargaz of $4.6 million (equal to $0.03 per diluted share).

Adjusted net income attributable to UGI for the 2016 nine-month period was $368.6 million (equal to $2.10 per diluted share) compared to $351.9 million (equal to $2.00 per diluted share) in the 2015 nine-month period. Our 2016 nine-month period results benefited from the full-period operations of French LPG distributor Finagaz which we acquired on May 29, 2015. The 2016 nine-month period adjusted net income attributable to UGI principally reflects the net effects of (1) a $66.6 million increase from UGI International (excluding the previously mentioned effects of Finagaz acquisition and integration expenses in both periods and the loss associated with an extinguishment of debt in the 2015 nine-month period) partially offset by (2) a $26.5 million decrease from UGI Utilities; (3) a $19.3 million decrease from Midstream & Marketing; and (4) a $2.5 million decrease from AmeriGas Propane (excluding the previously mentioned loss on extinguishments of debt in the 2016 nine-month period). During the 2016 nine-month period, each of our U.S. businesses and our UGI International European businesses were negatively impacted by significantly warmer-than-normal temperatures that reduced heating-related demand for our energy commodities primarily during the winter heating season. At UGI International and, to a lesser extent, AmeriGas Propane, higher average retail LPG unit margins resulting in large part from declining LPG wholesale commodity prices partially offset the impact on total margin from the reduced volumes sold.

Although the euro and the British pound sterling were slightly weaker during 2016, the effects of these weaker currencies did not have a material impact on UGI International net income for the three months ended June 30, 2016, and did not negatively impact year-over-year net income for the 2016 nine-month period due to higher gains on foreign currency exchange contracts used to hedge a portion of U.S. dollar purchases of LPG.

We believe each of our business units has sufficient liquidity in the form of revolving credit facilities and, with respect to Energy Services, also an accounts receivable securitization facility, to fund business operations during Fiscal 2016 (see “Financial Condition and Liquidity”).

Non-GAAP Financial Measures

As previously mentioned, UGI management uses “adjusted net income attributable to UGI” and “adjusted diluted earnings per share,” both of which are non-GAAP financial measures, when evaluating UGI’s overall performance. For the 2016 and 2015 three- and nine-month periods, adjusted net income attributable to UGI is net income attributable to UGI after excluding net after-tax gains and losses on commodity derivative instruments not associated with current-period transactions (principally comprising changes in unrealized gains and losses on commodity derivative instruments), Finagaz integration and acquisition expenses and losses associated with extinguishments of debt.

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 gains and losses on commodity derivative instruments not associated with current-period transactions and other significant discrete items that can affect the comparison of period-over-period results.

The following table reconciles consolidated net income attributable to UGI Corporation, the most directly comparable GAAP measure, to adjusted net income attributable to UGI Corporation, and reconciles diluted earnings per share, the most comparable GAAP measure, to adjusted diluted earnings per share, to reflect the adjustments referred to above:

(Dollars in millions, except per share amounts)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Nine Months Ended June 30, 2016	Nine Months Ended June 30, 2015
Adjusted net income attributable to UGI Corporation:				
Net income attributable to UGI Corporation	$ 60.7	$ 9.6	$ 408.5	$ 290.2
Net (gains) losses on commodity derivative instruments not associated with current period transactions (net of tax of $18.0, $2.4, $32.4 and $(27.7), respectively) (a) (b)	(29.6)	(4.9)	(55.6)	46.2
Integration and acquisition expenses associated with Finagaz (net of tax of $(1.7), $(1.8), $(5.9) and $(5.3), respectively) (a)	2.8	3.1	9.6	10.9
Loss on extinguishments of debt (net of tax of $(3.9), $(5.7), $(3.9) and $(5.7), respectively) (a) (c)	6.1	4.6	6.1	4.6
Adjusted net income attributable to UGI Corporation	$ 40.0	$ 12.4	$ 368.6	$ 351.9
Adjusted diluted earnings per share:				
UGI Corporation earnings per share - diluted	$ 0.34	$ 0.05	$ 2.33	$ 1.65
Net (gains) losses on commodity derivative instruments not associated with current period transactions(b)	(0.16)	(0.03)	(0.31)	0.26
Integration and acquisition expenses associated with Finagaz	0.02	0.02	0.05	0.06
Loss on extinguishments of debt	0.03	0.03	0.03	0.03
Adjusted diluted earnings per share	$ 0.23	$ 0.07	$ 2.10	$ 2.00

(a) Income taxes associated with pre-tax adjustments determined using statutory business unit tax rates (which approximates the consolidated effective tax rate).
(b) Includes the effects of rounding.
(c) Loss associated with extinguishment of debt in the 2015 three- and nine-month periods is included in interest expense on the condensed consolidated statements of income.

RESULTS OF OPERATIONS

2016 three-month period compared to the 2015 three-month period

Net Income Attributable to UGI Corporation by Business Unit

For the three months ended June 30,	2016		2015		Variance - Favorable (Unfavorable)	
(Dollars in millions)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane (a)	$ (4.5)	(7.4)%	$ (2.4)	(25.0)%	$ (2.1)	(87.5)%
UGI International (b)	19.2	31.6 %	(9.9)	(103.1)%	29.1	293.9 %
UGI Utilities	12.6	20.8 %	7.3	76.0 %	5.3	72.6 %
Midstream & Marketing	6.8	11.2 %	11.7	121.9 %	(4.9)	(41.9)%
Corporate & Other (c)	26.6	43.8 %	2.9	30.2 %	23.7	N.M.
Net income attributable to UGI Corporation	$ 60.7	100.0 %	$ 9.6	100.0 %	$ 51.1	532.3 %

(a) Three months ended June 30, 2016, includes net after-tax loss of $6.1 million on extinguishments of debt.
(b) Three months ended June 30, 2015, includes net after-tax loss of $4.6 million associated with an extinguishment of debt at Antargaz.
(c) Includes net after-tax gains on commodity derivative instruments not associated with current-period transactions of $29.6 million and $4.9 million for the three months ended June 30, 2016 and 2015, respectively.
N.M. — Variance is not meaningful.

AmeriGas Propane

For the three months ended June 30, (Dollars in millions)	2016	2015	Increase (Decrease)	
Revenues	$ 446.7	$ 478.0	$ (31.3)	(6.5)%
Total margin (a)	$ 275.9	$ 266.6	$ 9.3	3.5 %
Operating and administrative expenses	$ 217.2	$ 223.3	$ (6.1)	(2.7)%
Partnership Adjusted EBITDA (b)	$ 64.6	$ 48.9	$ 15.7	32.1 %
Operating income	$ 18.3	$ 0.8	$ 17.5	N.M.
Retail gallons sold (millions)	202.8	202.2	0.6	0.3 %
Degree days—% (warmer) than normal (c)	(7.5)%	(12.3)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin excludes net pre-tax gains of $27.8 million and $14.8 million on AmeriGas Propane commodity derivative instruments not associated with current-period transactions during the three months ended June 30, 2016 and 2015, respectively.

(b) Partnership Adjusted EBITDA (earnings before interest expense, income taxes and depreciation and amortization as adjusted for the effects of gains and losses on commodity derivative instruments not associated with current-period transactions and other gains and losses that competitors do not necessarily have) 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 Adjusted EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 14 to condensed consolidated financial statements). Partnership adjusted EBITDA for the three months ended June 30, 2016 excludes the $37.1 million loss on extinguishments of debt.

(c) Deviation from average heating degree days for the 30-year period 1981-2010 based upon national weather statistics provided by the National Oceanic and Atmospheric Administration (“NOAA”) for 344 Geo Regions in the United States, excluding Alaska and Hawaii.

N.M. — Variance is not meaningful.

AmeriGas Propane’s retail gallons sold during the 2016 three-month period increased 0.3% compared with the prior-year period. The increase in retail gallons sold in the 2016 three-month period reflects in part average temperatures based upon heating degree days that were slightly colder than the prior-year period.

Retail propane revenues decreased $27.2 million during the 2016 three-month period reflecting lower average retail selling prices ($28.4 million) partially offset by the effects of the higher retail volumes sold ($1.2 million). Wholesale propane revenues decreased $1.3 million during the 2016 three-month period reflecting the effects of lower wholesale volumes sold ($1.5 million) partially offset by slightly higher wholesale selling prices ($0.2 million). Average daily wholesale propane commodity prices during the 2016 three-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 5% higher than such prices during the 2015 three-month period. Other revenues in the 2016 three-month period were $2.8 million lower than in the prior-year period. Total cost of sales decreased $40.6 million during the 2016 three-month period principally reflecting the effects of lower Partnership average propane product costs ($37.2 million) and lower other cost of sales ($2.5 million).

AmeriGas Propane total margin increased $9.3 million in the 2016 three-month period principally reflecting higher retail propane total margin ($9.8 million). The increase in retail propane total margin principally reflects slightly higher average propane retail unit margin.

Partnership Adjusted EBITDA in the 2016 three-month period increased $15.7 million principally reflecting the $9.3 million increase in total margin and lower operating and administrative expenses ($6.1 million). The decrease in operating and administrative expenses reflects, among other things, lower employee compensation and benefits expenses ($6.5 million) and lower vehicle fuel costs ($2.4 million) partially offset by higher self-insured casualty and liability expenses. AmeriGas Propane operating income increased $17.5 million in the 2016 three-month period principally reflecting the previously mentioned higher Partnership Adjusted EBITDA ($15.7 million) and slightly lower depreciation expense.

UGI International

For the three months ended June 30, (Dollars in millions)	2016	2015	Increase	
Revenues	$ 395.5	$ 346.8	$ 48.7	14.0 %
Total margin (a)	$ 215.8	$ 137.1	$ 78.7	57.4 %
Operating and administrative expenses	$ 154.9	$ 117.0	$ 37.9	32.4 %
Operating income (loss)	$ 33.5	$ (0.3)	$ 33.8	N.M.
Income (loss) before income taxes (b)	$ 27.7	$ (16.9)	$ 44.6	(263.9)%
Retail gallons sold (millions) (c)	169.9	151.5	18.4	12.1 %
UGI France degree days—% (warmer) than normal (d)	(5.6)%	(23.7)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the three months ended June 30, 2016 and June 30, 2015 excludes net pre-tax gains of $13.1 million and $1.1 million on UGI International's commodity derivative instruments not associated with current-period transactions.
(b) Loss before income taxes for the 2015 three-month period includes $10.3 million loss associated with an extinguishment of debt at Antargaz which amount is included in interest expense.
(c) Excludes retail gallons from our LPG business in China which was sold in March 2016.
(d) Deviation from average heating degree days for the 30-year period 1981-2010 at locations in our UGI France service territories.
N.M. - Variance is not meaningful.

UGI International's 2016 three-month period results include the full-period results of Finagaz which was acquired on May 29, 2015. The acquisition of Finagaz nearly doubled our retail distribution business in France and is a significant contributor to the variances in the table above.

Based upon heating degree day data, temperatures during the 2016 three-month period at UGI France were 5.6% warmer than normal but 24% colder than the prior year. Total retail gallons sold during the 2016 three-month period were significantly higher than the prior-year period principally reflecting incremental retail LPG gallons associated with Finagaz and, to a much lesser extent, the effects of the colder weather on our legacy UGI France operations and incremental retail gallons associated with smaller-scale acquisitions at Flaga and AvantiGas. Partially offsetting these increases was the impact on retail volumes from Flaga exiting its low-margin autogas business in Poland (24.9 million gallons). During the 2016 three-month period, average wholesale commodity prices for both propane and butane in northwest Europe were approximately 20% lower than in the prior-year period.

UGI International base-currency results are translated into U.S. dollars based upon exchange rates experienced during the reporting periods. The functional currency of a significant portion of our UGI International results is the euro and, to a much lesser extent, the British pound sterling. During the 2016 and 2015 three-month periods, the average un-weighted euro-to-dollar translation rates were approximately $1.13 and $1.11, respectively, and the average unweighted British pound sterling-to-dollar translation rates were approximately $1.43 and $1.53, respectively. These differences in exchange rates did not have a significant impact on UGI International net income.

UGI International revenues increased $48.7 million during the 2016 three-month period principally reflecting incremental revenues from Finagaz and, to a much lesser extent, incremental revenues associated with the smaller-scale acquisitions at Flaga and AvantiGas. These increases were substantially offset by lower average LPG selling prices at each of our legacy European LPG businesses. The lower average LPG selling prices in the 2016 three-month period resulted from lower average LPG wholesale commodity prices and the impact of exiting the low-margin autogas business in Poland. UGI International cost of sales decreased $30.0 million during the 2016 three-month period principally reflecting the effects of lower average LPG wholesale commodity prices and lower cost of sales associated with exiting the autogas business in Poland. These decreases were partially offset by incremental cost of sales associated with Finagaz and, to a much lesser extent, the smaller scale acquisitions at Flaga and AvantiGas.

UGI International total margin increased $78.7 million primarily reflecting incremental margin from Finagaz, the effects of higher LPG unit margins and retail volumes principally at our legacy UGI France LPG business, and higher natural gas total margin at UGI France on higher volume sales. The higher legacy UGI France LPG retail volumes reflects the effects of colder spring weather while the higher average UGI France legacy LPG business unit margins resulted in large part from declining LPG wholesale commodity prices.

The $33.8 million increase in operating income principally reflects the previously mentioned $78.7 million increase in total margin partially offset by (1) a $37.9 million increase in operating and administrative expenses and (2) higher depreciation and amortization expense. The increases in operating and administrative expenses and depreciation and amortization expense primarily reflect incremental expenses associated with Finagaz. Operating and administrative expenses include $4.5 million and $4.9 million of Finagaz integration and acquisition-related expenses in the 2016 and 2015 three-month periods, respectively. UGI International income before income taxes increased $44.6 million principally reflecting the previously mentioned $33.8 million increase in UGI International operating income and the absence of a $10.3 million loss recorded in the prior year associated with an extinguishment of debt at Antargaz which is reflected in interest expense. UGI International interest expense was $10.8 million lower than the prior-year three-month period as the prior-year includes the $10.3 million loss on extinguishment of debt at Antargaz. Excluding the effects of this loss, UGI International interest expense was slightly lower as lower average interest rates on UGI International's long-term debt was partially offset by higher average long-term debt outstanding at UGI France resulting from the acquisition of Finagaz.

UGI Utilities

For the three months ended June 30,	2016	2015	Increase (Decrease)	
(Dollars in millions)				
Revenues	$ 140.3	$ 143.5	$ (3.2)	(2.2)%
Total margin (a)	$ 94.8	$ 88.6	$ 6.2	7.0 %
Operating and administrative expenses	$ 46.1	$ 54.0	$ (7.9)	(14.6)%
Operating income	$ 29.8	$ 20.2	$ 9.6	47.5 %
Income before income taxes	$ 20.7	$ 10.3	$ 10.4	101.0 %
Gas Utility system throughput—billions of cubic feet ("bcf")				
Core market	10.3	8.9	1.4	15.7 %
Total	43.6	38.6	5.0	13.0 %
Electric Utility distribution sales - millions of kilowatt hours ("gwh")	215.7	219.7	(4.0)	(1.8)%
Gas Utility degree days—% colder (warmer) than normal (b)	11.9%	(17.2)%	—	—

(a) Total margin represents total revenues less total cost of sales and revenue-related taxes, i.e. Electric Utility gross receipts taxes, of $1.1 million and $1.2 million during the three months ended June 30, 2016 and 2015, respectively. For financial statement purposes, revenue-related taxes are included in utility taxes other than income taxes in the Condensed Consolidated Statements of Income.

(b) Deviation from average heating degree days for the 15-year period 2000-2014 based upon weather statistics provided by NOAA for airports located within Gas Utility's service territory.

Temperatures in Gas Utility's service territory during the 2016 three-month period based upon heating degree days were 11.9% colder than normal and 38% colder than the 2015 three-month period. Core market volumes increased 1.4 bcf (15.7%) reflecting the effects of the colder spring weather. Total Gas Utility distribution system throughput increased 5.0 bcf (13.0%) principally reflecting higher large firm fixed-fee delivery service volumes and, to a lesser extent, the 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 lesser extent, residential and small commercial customers who purchase their gas from alternate suppliers. Electric Utility kilowatt-hour sales were slightly lower than in the prior-year three-month period.

UGI Utilities revenues decreased $3.2 million principally reflecting lower Electric Utility revenues ($3.6 million) while Gas Utility revenues were slightly higher than the prior-year three-month period. The lower 2016 three-month period Electric Utility revenues principally resulted from lower transmission revenues and, to a lesser extent, the effects of lower DS rates and slightly lower sales volumes. The slight increase in Gas Utility revenues principally reflects higher revenues from firm delivery service customers ($2.2 million), resulting from higher firm delivery service volumes, and an increase in core market revenues ($0.3 million) partially offset by lower off-system sales revenues ($2.2 million). The slight increase in Gas Utility core market revenues reflects the effects of the higher core market throughput ($13.4 million) substantially offset by lower average PGC rates ($13.1 million) associated with retail core-market revenues. Because Gas Utility and Electric Utility are subject to reconcilable PGC and DS recovery mechanisms, increases or decreases in the actual cost of gas or electricity associated with customers who purchase their gas or electricity from UGI Utilities impact revenues and cost of sales but have no direct effect on retail core-market margin (see Note 6 to condensed consolidated financial statements). UGI Utilities cost of sales was $44.4 million in the 2016 three-month period compared with $53.7 million in the 2015 three-month period principally reflecting the combined effects of lower average Gas

Utility PGC rates ($5.7 million) and lower cost of sales associated with off-system sales ($2.2 million). Electric Utility cost of sales in the 2016 three-month period was slightly lower primarily reflecting lower DS rates.

UGI Utilities 2016 three-month period total margin increased $6.2 million principally reflecting higher Gas Utility total margin from core market customers ($6.3 million) and slightly higher total margin from delivery service customers resulting from the higher throughput ($1.6 million). Electric Utility margin decreased $1.8 million principally reflecting lower transmission revenues and, to a much lesser extent, the slightly lower volume sales.

UGI Utilities operating income and income before income taxes increased $9.6 million and $10.4 million, respectively. The increases in operating income and income before income taxes during the 2016 three-month period principally reflect the previously mentioned increase in total margin ($6.2 million) and a $7.9 million decrease in operating and administrative expenses including lower distribution system ($2.8 million) and customer account expenses ($2.7 million). These benefits were partially offset by lower other operating income as the prior-year period included incremental income from construction services and the sale of PNG’s heating, ventilation and air-conditioning business. The increase in income before income taxes also reflects lower interest expense principally due to lower average long-term debt outstanding.

Midstream & Marketing

For the three months ended June 30,	2016	2015	Decrease	
(Dollars in millions)				
Revenues (a)	$ 166.2	$ 203.1	$ (36.9)	(18.2)%
Total margin (b)	$ 41.9	$ 49.8	$ (7.9)	(15.9)%
Operating and administrative expenses	$ 22.7	$ 23.2	$ (0.5)	(2.2)%
Operating income	$ 11.3	$ 19.5	$ (8.2)	(42.1)%
Income before income taxes	$ 10.9	$ 19.0	$ (8.1)	(42.6)%

(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 pre-tax gains on commodity derivative instruments not associated with current period transactions of $26.9 million and $2.2 million during the 2016 three-month period and the 2015 three-month period, respectively.

Midstream & Marketing 2016 three-month period revenues were $36.9 million lower than the 2015 three-month period principally reflecting lower natural gas revenues ($17.5 million) and, to a much lesser extent, lower capacity management ($7.4 million), electric generation ($4.6 million) and retail power ($3.5 million) revenues. The decrease in natural gas revenues principally reflects lower wholesale and retail natural gas prices during the 2016 three-month period while the lower retail power revenues principally reflects lower sales volumes. The decline in capacity management revenues reflects lower average prices for capacity in the current-year period as the current-year period experienced lower locational basis differences due to less volatility in capacity values between Marcellus and non-Marcellus delivery points. The decline in electric generation total revenues reflects lower production volumes due in large part to planned outages at the Conemaugh electricity generating station. These decreases in revenues were partially offset by higher natural gas gathering revenues ($2.1 million). Midstream & Marketing cost of sales decreased to $124.3 million in the 2016 three-month period compared to $153.3 million in the 2015 three-month period principally reflecting lower natural gas cost of sales ($19.2 million) principally on lower natural gas prices and lower cost of sales associated with the decline in retail power ($3.2 million) and electric generation ($2.8 million) sales volumes.

Midstream & Marketing total margin decreased $7.9 million in the 2016 three-month period principally reflecting lower capacity management total margin ($7.4 million) and lower electric generation total margin ($1.8 million) partially offset by higher natural gas total margin. The lower capacity management margin in the 2016 three-month period principally reflects lower average year-over-year prices for pipeline capacity as the current-year period experienced lower locational basis differences due to less volatility in capacity values between Marcellus and non-Marcellus delivery points. The decline in electric generation total margin reflects lower production volumes during the 2016 three-month period due principally to the previously mentioned planned outages and lower power prices. The increase in natural gas marketing total margin principally reflects the effects of higher volumes sold during the 2016 three-month period.

Midstream & Marketing operating income and income before income taxes during the 2016 three-month period decreased $8.2 million and $8.1 million, respectively, principally reflecting the previously mentioned decrease in total margin ($7.9 million) and slightly higher depreciation expense principally associated with our natural gas gathering assets. Operating and administrative expenses were slightly lower in the 2016 three-month period principally reflecting lower operating and administrative expenses associated with our HVAC business partially offset by higher electric generation maintenance expenses.

Interest Expense and Income Taxes

Our consolidated interest expense during the 2016 three-month period was $56.4 million, $11.1 million lower than the $67.5 million of interest expense recorded during the 2015 three-month period. Interest expense in the 2015 three-month period includes the previously mentioned $10.3 million loss associated with an extinguishment of debt at Antargaz. Excluding the impact of this loss, interest expense was slightly lower principally reflecting lower average UGI Utilities long-term debt outstanding. Our effective income tax rate as a percentage of pre-tax income in the 2016 and 2015 three-month periods (excluding the effects on such rate of pre-tax income associated with noncontrolling interests not subject to federal income taxes) reflects the impacts in both periods of changes in the estimated annual effective income tax rates.

2016 nine-month period compared to the 2015 nine-month period

Net Income Attributable to UGI Corporation by Business Unit

For the nine months ended June 30,	2016		2015		Variance - Favorable (Unfavorable)	
(Dollars in millions)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane (a)	$ 53.4	13.1%	$ 62.0	21.4 %	$ (8.6)	(13.9)%
UGI International (b)	132.3	32.4%	59.8	20.6 %	72.5	121.2 %
UGI Utilities	99.2	24.3%	125.7	43.3 %	(26.5)	(21.1)%
Midstream & Marketing	77.2	18.9%	96.5	33.3 %	(19.3)	(20.0)%
Corporate & Other (c)	46.4	11.4%	(53.8)	(18.5)%	100.2	N.M.
Net income attributable to UGI Corporation	$ 408.5	100.0%	$ 290.2	100.0 %	$ 118.3	40.8 %

(a) Nine months ended June 30, 2016, includes a net after-tax loss of $6.1 million on extinguishments of debt.
(b) Nine months ended June 30, 2015, includes a net after-tax loss of $4.6 million associated with an extinguishment of debt at Antargaz.
(c) Includes net after-tax gains (losses) on commodity derivative instruments not associated with current-period transactions of $55.6 million and $(46.2) million for the nine months ended June 30, 2016 and 2015, respectively.
N.M. — Variance is not meaningful.

AmeriGas Propane

For the nine months ended June 30,	2016	2015	Decrease	
(Dollars in millions)				
Revenues	$ 1,918.3	$ 2,467.1	$ (548.8)	(22.2)%
Total margin (a)	$ 1,206.1	$ 1,288.1	$ (82.0)	(6.4)%
Operating and administrative expenses	$ 686.8	$ 728.1	$ (41.3)	(5.7)%
Partnership Adjusted EBITDA (b)	$ 537.7	$ 579.5	$ (41.8)	(7.2)%
Operating income	$ 398.3	$ 437.4	$ (39.1)	(8.9)%
Retail gallons sold (millions)	883.7	990.4	(106.7)	(10.8)%
Degree days—% (warmer) than normal (c)	(14.3)%	(1.9)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin excludes net pre-tax gains (losses) of $61.7 million and $(48.7) million on AmeriGas Propane commodity derivative instruments not associated with current-period transactions during the nine months ended June 30, 2016 and 2015, respectively.
(b) Partnership Adjusted EBITDA (earnings before interest expense, income taxes and depreciation and amortization as adjusted for the effects of gains and losses on commodity derivative instruments not associated with current-period transactions and other gains and losses that competitors do not necessarily have) 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 Adjusted EBITDA as the primary measure of segment profitability for the AmeriGas Propane

segment (see Note 14 to condensed consolidated financial statements). Partnership adjusted EBITDA for the nine months ended June 30, 2016 excludes the $37.1 million loss on extinguishments of debt.

(c) Deviation from average heating degree days for the 30-year period 1981-2010 based upon national weather statistics provided by the NOAA for 344 Geo Regions in the United States, excluding Alaska and Hawaii.

AmeriGas Propane's retail gallons sold during the 2016 nine-month period decreased 10.8% compared with the prior-year period. The decline in retail gallons sold in the 2016 nine-month period principally reflects average temperatures based upon heating degree days that were nearly 14.3% warmer than normal and 12.6% warmer than the prior-year period.

Retail propane revenues decreased $524.2 million during the 2016 nine-month period reflecting lower average retail selling prices ($285.1 million), principally the result of the lower propane product costs, and the effects of the lower retail volumes sold ($239.1 million). Wholesale propane revenues decreased $12.0 million during the 2016 nine-month period reflecting the effects of lower wholesale selling prices ($10.2 million) and lower wholesale volumes sold ($1.8 million). Average daily wholesale propane commodity prices during the 2016 nine-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 26% lower than such prices during the 2015 nine-month period. Other revenues in the 2016 nine-month period were $12.6 million lower than in the prior-year period principally reflecting lower fee income. Total cost of sales decreased $466.8 million during the 2016 nine-month period principally reflecting the effects of the significantly lower average propane product costs ($343.2 million) and the effects of the lower retail and wholesale volumes sold ($118.1 million) on propane cost of sales.

AmeriGas Propane total margin decreased $82.0 million in the 2016 nine-month period principally reflecting lower retail propane total margin ($75.2 million) and, to a much lesser extent, lower margin from ancillary sales and services. The decrease in retail propane total margin largely reflects the previously mentioned decline in retail gallons sold partially offset by higher average propane retail unit margin resulting from the benefits of declining wholesale propane commodity prices.

Partnership Adjusted EBITDA in the 2016 nine-month period decreased $41.8 million principally reflecting the lower total margin ($82.0 million) partially offset by lower operating and administrative expenses ($41.3 million). The decrease in operating and administrative expenses reflects, among other things, lower vehicle fuel ($12.0 million), employee compensation and benefits ($11.6 million), provision for uncollectible accounts ($4.4 million) and plant and equipment operating and maintenance ($4.1 million) expenses. AmeriGas Propane operating income decreased $39.1 million in the 2016 nine-month period principally reflecting the lower Partnership Adjusted EBITDA ($41.8 million) partially offset by slightly lower depreciation expense.

UGI International

For the nine months ended June 30,		2016		2015		Increase	
(Dollars in millions)							
Revenues	$	1,552.4	$	1,429.4	$	123.0	8.6%
Total margin (a)	$	798.9	$	514.2	$	284.7	55.4%
Operating and administrative expenses	$	480.9	$	343.1	$	137.8	40.2%
Operating income	$	230.1	$	117.9	$	112.2	95.2%
Income before income taxes (b)	$	211.2	$	87.8	$	123.4	140.5%
Retail gallons sold (millions) (c)		669.5		521.8		147.7	28.3%
UGI France degree days—% (warmer) than normal (d)		(12.4)%		(11.6)%		—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the nine months ended June 30, 2016 and 2015 excludes net pre-tax gains (losses) of $32.1 million and $(18.0) million on UGI International's commodity derivative instruments not associated with current-period transactions.

(b) Income before income taxes for the 2015 nine-month period includes $10.3 million loss associated with an extinguishment of debt at Antargaz which amount is included in interest expense.

(c) Excludes retail gallons from our LPG business in China which was sold in March 2016.

(d) Deviation from average heating degree days for the 30-year period 1981-2010 at locations in our UGI France service territories.

UGI International's 2016 nine-month period results include the full-period results of Finagaz which was acquired on May 29, 2015. The acquisition of Finagaz nearly doubled our retail distribution business in France and is a significant contributor to the variances in the table above.

Based upon heating degree day data, temperatures during the 2016 nine-month period were significantly warmer than normal and comparable with temperatures experienced during the 2015 nine-month period. Total retail gallons sold during the 2016 nine-month period were significantly higher principally reflecting incremental retail LPG gallons associated with Finagaz and, to a much lesser extent, retail gallons associated with small-scale acquisitions at Flaga and AvantiGas. Partially offsetting these increases was the impact on retail volumes of exiting the low-margin autogas business in Poland (42.6 million gallons). During the 2016 nine-month period, average wholesale commodity prices for both propane and butane in northwest Europe were approximately 25% lower than in the prior-year period.

UGI International base-currency results are translated into U.S. dollars based upon exchange rates experienced during the reporting periods. The functional currency of a significant portion of our UGI International results is the euro and, to a much lesser extent, the British pound sterling. During the 2016 and 2015 nine-month periods, the average un-weighted euro-to-dollar translation rates were approximately $1.10 and $1.16, respectively, and the average unweighted British pound sterling-to-dollar translation rates were approximately $1.46 and $1.55, respectively. Although the euro and the British pound sterling were weaker during the 2016 nine-month period and affect the comparisons of amounts in the table above, these weaker currencies did not negatively impact UGI International net income due to higher gains on foreign currency exchange contracts used to hedge a portion of U.S. dollar purchases of LPG.

UGI International revenues increased $123.0 million during the 2016 nine-month period principally reflecting incremental revenues from Finagaz and, to a much lesser extent, incremental revenues associated with the small-scale acquisitions at Flaga and AvantiGas. These increases in revenues were substantially offset by lower average LPG selling prices at each of our legacy European LPG businesses and, to a lesser extent, the impact of exiting the low-margin autogas business in Poland and the effects of the weaker euro and the British pound sterling. The lower average LPG sales prices in the 2016 nine-month period resulted from lower average LPG wholesale commodity prices. UGI International cost of sales decreased $161.7 million during the 2016 nine-month period principally reflecting the effects of lower average LPG wholesale commodity prices and, to a much lesser extent, the absence of certain low-margin autogas volumes at Flaga, the effects of the weaker euro and the British pound sterling, and higher gains from foreign currency exchange contracts used to hedge a portion of U.S. dollar purchases of LPG. These decreases in cost of sales were partially offset by incremental cost of sales associated with Finagaz.

UGI International total margin increased $284.7 million primarily reflecting incremental margin from Finagaz and, to a much lesser extent, higher average unit margins principally at our legacy UGI France business and Flaga resulting from the benefits of declining LPG wholesale commodity prices, and the impact of the small-scale acquisitions at Flaga and AvantiGas. The impact of the slightly higher local currency total margin in our legacy European LPG businesses was offset by the effects on such margin of the weaker euro and the British pound sterling.

The $112.2 million increase in operating income principally reflects the previously mentioned $284.7 million increase in total margin partially offset by a $137.8 million increase in operating and administrative expenses, a $25.3 million increase in depreciation and amortization expense, and lower other operating income. The increase in operating and administrative expenses and the higher depreciation and amortization expense primarily reflects incremental expenses associated with Finagaz and, to a much lesser extent, small-scale acquisitions at Flaga and AvantiGas partially offset by the effects of the weaker euro and British pound sterling on legacy business local currency operating expenses. Operating and administrative costs include $15.5 million and $16.2 million of Finagaz integration and acquisition-related expenses in the 2016 and 2015 nine-month periods, respectively. UGI International income before income taxes increased $123.4 million principally reflecting the previously mentioned $112.2 million increase in UGI International operating income and the absence of the $10.3 million loss recorded in the prior year associated with an extinguishment of debt at Antargaz which is reflected in interest expense. UGI International interest expense was $10.2 million lower than the prior-year nine-month period as the prior-year includes the $10.3 million loss on extinguishment of debt at Antargaz. Excluding this loss, UGI International interest expense was about equal to the prior-year nine-month period as higher average long-term debt outstanding at UGI France as a result of the acquisition of Finagaz was offset by lower average interest rates on UGI International's long-term debt and the effects of the weaker euro.

UGI Utilities

For the nine months ended June 30,		2016		2015		Decrease	
(Dollars in millions)							
Revenues	$	660.3	$	931.4	$	(271.1)	(29.1)%
Total margin (a)	$	399.5	$	451.9	$	(52.4)	(11.6)%
Operating and administrative expenses	$	145.2	$	166.4	$	(21.2)	(12.7)%
Operating income	$	192.6	$	238.5	$	(45.9)	(19.2)%
Income before income taxes	$	164.7	$	207.3	$	(42.6)	(20.5)%
Gas Utility system throughput—billions of cubic feet ("bcf")							
Core market		61.7		76.4		(14.7)	(19.2)%
Total		165.6		176.3		(10.7)	(6.1)%
Electric Utility distribution sales - gwh		706.0		764.4		(58.4)	(7.6)%
Gas Utility degree days—% (warmer) colder than normal (b)		(12.9)%		7.5%		—	—

(a) Total margin represents total revenues less total cost of sales and revenue-related taxes, i.e. Electric Utility gross receipts taxes, of $3.5 million and $4.4 million during the nine months ended June 30, 2016 and 2015, respectively. For financial statement purposes, revenue-related taxes are included in utility taxes other than income taxes in the Condensed Consolidated Statements of Income.

(b) Deviation from average heating degree days for the 15-year period 2000-2014 based upon weather statistics provided by NOAA for airports located within Gas Utility's service territory.

Temperatures in Gas Utility's service territory during the 2016 nine-month period based upon heating degree days were 12.9% warmer than normal and 18.0% warmer than the 2015 nine-month period. In particular, Gas Utility temperatures in the critical heating-season month of December were 37% warmer than normal. Core market volumes declined 14.7 bcf (19.2%) reflecting the effects of the significantly warmer weather. Total Gas Utility distribution system throughput decreased 10.7 bcf (6.1%) principally reflecting the lower core market volumes partially offset by higher large firm delivery service volumes. Electric Utility kilowatt-hour sales were 7.6% lower than in the prior-year period principally reflecting the impact of the warmer weather on heating-related sales.

UGI Utilities revenues decreased principally reflecting a $252.9 million decrease in Gas Utility revenues and lower Electric Utility revenues ($17.3 million). The lower Gas Utility revenues principally reflect a decrease in core market revenues ($200.0 million) and lower off-system sales revenues ($50.9 million). The decrease in Gas Utility core market revenues reflects the effects of the lower core market throughput ($129.0 million) and lower average PGC rates during the 2016 nine-month period ($71.0 million). The lower Electric Utility revenues principally resulted from lower DS rates, lower sales volumes and lower transmission revenue in the 2016 nine-month period. UGI Utilities cost of sales was $257.3 million in the 2016 nine-month period compared with $475.1 million in the 2015 nine-month period principally reflecting the combined effects of the lower average Gas Utility PGC rates ($155.5 million), lower cost of sales associated with off-system sales ($50.9 million) and lower Gas Utility retail core-market volumes sold ($14.6 million). Electric Utility cost of sales was lower reflecting lower volumes sold and lower DS rates.

UGI Utilities 2016 nine-month period total margin decreased $52.4 million principally reflecting lower Gas Utility total margin from core market customers ($44.5 million) and, to a much lesser extent, lower total margin from large firm delivery service customers. The decrease in Gas Utility core market margin reflects the lower core market throughput. Electric Utility total margin decreased $3.6 million principally reflecting the lower volume sales as a result of the warmer nine-month period weather and lower transmission revenue.

UGI Utilities operating income and income before income taxes decreased $45.9 million and $42.6 million, respectively. The decreases in operating income and income before income taxes during the 2016 nine-month period principally reflects the decrease in total margin ($52.4 million), higher depreciation expense ($3.5 million) and lower other operating income which includes, among other things, higher environmental matters expense ($3.9 million), higher interest on PGC overcollections and lower margin from off-system sales. UGI Utilities operating and administrative expenses were $21.2 million lower primarily reflecting lower net preliminary development stage expenses associated with an information technology ("IT") project and, to a lesser extent, lower uncollectible accounts and system maintenance expenses. During the three months ended March 31, 2016, we determined that certain preliminary stage costs associated with the IT project were probable of future recovery in rates in accordance with GAAP related to rate regulated entities. As a result, during the three months ended March 31, 2016, we capitalized $5.8 million of such costs including $5.4 million that had been expensed prior to Fiscal 2016 (including $2.9 million of such costs that had been expensed during the 2015 nine-month period), and recorded associated increases to utility plant and regulatory assets (See Note 6 to condensed consolidated financial statements). Income before income taxes also reflects lower interest expense principally due to lower average long-term debt outstanding.

Midstream & Marketing

For the nine months ended June 30,	2016		2015		Decrease		
(Dollars in millions)							
Revenues (a)	$	692.3	$	974.8	$	(282.5)	(29.0)%
Total margin (b)	$	223.4	$	261.8	$	(38.4)	(14.7)%
Operating and administrative expenses	$	68.4	$	76.8	$	(8.4)	(10.9)%
Operating income	$	132.0	$	164.2	$	(32.2)	(19.6)%
Income before income taxes	$	130.3	$	162.6	$	(32.3)	(19.9)%

(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 pre-tax gains and (losses) on commodity derivative instruments not associated with current period transactions of $39.3 million and $(42.8) million during the 2016 nine-month period and the 2015 nine-month period, respectively.

Midstream & Marketing's 2016 nine-month period results were negatively impacted by significantly warmer weather in its principal Mid-Atlantic service territory. Temperatures across Midstream & Marketing's energy marketing territory were approximately 16.7% warmer than normal and 20.6% warmer than the prior-year period. Midstream & Marketing 2016 nine-month period revenues were $282.5 million lower than the 2015 nine-month period principally reflecting lower natural gas revenues ($227.2 million) and, to a much lesser extent, lower capacity management ($33.1 million), retail power ($18.4 million) and electric generation ($15.2 million) revenues. The decrease in natural gas revenues reflects lower wholesale and retail natural gas prices during the 2016 nine-month period and to a lesser extent lower natural gas volumes resulting from the warmer weather while the lower retail power revenues principally reflect lower weather-related sales volumes and lower retail power prices. The decline in capacity management revenues reflects lower average prices for capacity as the current-year period experienced lower locational basis differences due to less volatility in capacity values between Marcellus and non-Marcellus delivery points. The decline in electric generation revenues reflects lower average electricity prices and lower electricity production volumes during the 2016 nine-month period due in large part to the effects of the warmer weather and the impact of planned outages. These decreases in revenues were partially offset by higher combined peaking and natural gas gathering revenues ($25.9 million). Midstream & Marketing cost of sales decreased to $468.9 million in the 2016 nine-month period compared to $713.0 million in the 2015 nine-month period principally reflecting lower natural gas cost of sales ($213.6 million) principally on lower natural gas prices and lower cost of sales associated with the decline in retail power ($16.5 million) and electric generation ($7.9 million) sales.

Midstream & Marketing total margin decreased $38.4 million in the 2016 nine-month period principally reflecting lower capacity management total margin ($33.1 million), lower natural gas and retail power total margin ($16.4 million) and lower electric generation total margin ($7.3 million). The lower capacity management margin in the 2016 nine-month period principally reflects lower average prices for capacity in the current-year period as the current-year period experienced lower locational basis differences due to less volatility in capacity values between Marcellus and non-Marcellus delivery points. The decline in natural gas marketing total margin principally reflects the effects of lower average unit margins and lower volumes sold due to the warmer weather. The decline in electric generation total margin reflects lower average electricity prices and lower electricity production volumes. These decreases in margin were partially offset by slightly higher combined natural gas gathering and peaking total margin ($25.0 million) reflecting the expansion of our natural gas gathering assets and higher demand for peaking services.

Midstream & Marketing operating income and income before income taxes during the 2016 nine-month period decreased $32.2 million and $32.3 million, respectively, principally reflecting the previously mentioned decrease in total margin ($38.4 million) partially offset by slightly lower operating and administrative expenses. Operating and administrative expenses were lower in the 2016 nine-month period due in large part to lower operating expenses in the HVAC business ($5.5 million) and greater costs associated with our generation facilities in the prior-year period. Depreciation expense was slightly higher in the 2016 nine-month period principally reflecting incremental depreciation expense associated with our natural gas gathering assets and Electric Generation facilities, principally the Conemaugh electricity generating unit.

Interest Expense and Income Taxes

Our consolidated interest expense during the 2016 nine-month period was $171.6 million, $13.1 million lower than the $184.7 million of interest expense recorded during the 2015 nine-month period. Interest expense in the 2015 nine-month period includes a $10.3 million loss associated with an extinguishment of debt at Antargaz. Excluding the impact of this loss, interest expense was slightly lower principally reflecting lower average UGI Utilities long-term debt outstanding. UGI International interest expense, excluding the impact of the loss on extinguishment of debt, was about equal to the prior-year nine-month period as higher average long-term debt outstanding at UGI France resulting from the acquisition of Finagaz was offset by lower average interest rates on UGI International's long-term debt and the effects of the weaker euro. Our effective income tax rate as a percentage of pre-tax income for the 2016 nine-month period (excluding the effects on such rate of pre-tax income associated with noncontrolling interests not subject to federal income taxes) was 39.2%, substantially equal to the 39.5% rate in the prior-year nine-month period.

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.

The primary sources of UGI's cash and cash equivalents are the dividends and other cash payments made to UGI or its corporate subsidiaries by its principal business units. Our cash and cash equivalents totaled $909.2 million at June 30, 2016, compared with $369.7 million at September 30, 2015. Excluding cash and cash equivalents that reside at UGI's operating subsidiaries, at June 30, 2016 and September 30, 2015, UGI had $119.5 million and $77.2 million of cash and cash equivalents, respectively, most of which are located in the U.S. Such cash is available to pay dividends on UGI Common Stock and for investment purposes.

The Company's debt outstanding at June 30, 2016, totaled $4,300.9 million (including current maturities of long-term debt of $382.2 million and short-term borrowings of $144.0 million) compared to debt outstanding at September 30, 2015, of $3,889.7 million (including current maturities of long-term debt of $258.0 million and short-term borrowings of $189.9 million). Total debt outstanding at June 30, 2016, consists of (1) $2,729.5 million of Partnership debt; (2) $780.4 million of UGI International debt; (3) $780.0 million of UGI Utilities debt; (4) $0.7 million of Energy Services debt; and (5) $10.3 million of other debt.

At June 30, 2016, the significantly higher cash and cash equivalents, and the higher total long-term debt, reflects the issuance of long-term debt at AmeriGas Partners and UGI Utilities in late June 2016 and the subsequent timing of the use of the proceeds to repay debt. For further information on these and other debt transactions occurring during the 2016 nine-month period, see "Long-term Debt and Short-term Borrowings" below and Note 8 to condensed consolidated financial statements.

Long-term Debt and Short-term Borrowings

AmeriGas Partners. AmeriGas Partners' total debt at June 30, 2016, includes $2,683.7 million of AmeriGas Partners' Senior Notes, $11.4 million of AmeriGas OLP short-term borrowings and $34.4 million of other long-term debt.

On June 27, 2016, AmeriGas Partners issued $675.0 million principal amount of 5.625% Senior Notes due May 2024 (the "5.625% Senior Notes") and $675.0 million principal amount of 5.875% Senior Notes due August 2026 (the "5.875% Senior Notes")(collectively, the "AmeriGas Senior Notes").

On June 20, 2016, AmeriGas Partners announced cash tender offers to purchase all of AmeriGas Partners' 6.50% Senior Notes, 6.75% Senior Notes and 6.25% Senior Notes (collectively, the "Tendered Notes"). A portion of the proceeds from the issuance of the previously mentioned AmeriGas Senior Notes, net of underwriters' discounts and offering expenses, were used on June 27, 2016, to redeem Tendered Notes having an aggregate principal amount of $917.1 million, plus tender premiums and accrued and unpaid interest. The remaining net proceeds from the issuance of the AmeriGas Senior Notes were used in July, and will be used in August 2016, to redeem the remaining $352.9 million principal amount of senior notes not paid on June 27, 2016, pursuant to the June 20, 2016, tender offer and for general corporate purposes (as further described below and in Note 8 to condensed consolidated financial statements).

On June 27, 2016, AmeriGas Partners issued a notice of cash redemption for the remaining 6.50% Senior Notes, 6.75% Senior Notes, and 6.25% Senior Notes not previously tendered, plus call premiums and accrued and unpaid interest. The redemption date for the 6.75% Senior Notes and the 6.50% Senior Notes was July 27, 2016, and the redemption date for the 6.25% Senior Notes is August 22, 2016. These senior notes have been included in “Current maturities of long-term debt” on the June 30, 2016, Condensed Consolidated Balance Sheet. The Partnership expects to recognize a loss on extinguishment of debt of approximately $12 million during the fourth quarter of Fiscal 2016 associated with these redemptions.

UGI International. UGI International’s total debt at June 30, 2016, includes $666.5 million (€600 million) outstanding under France SAS’s 2015 Senior Facilities Agreement, $59.1 million under Flaga’s U.S. dollar-denominated term loan and $50.9 million (€45.8 million) outstanding under Flaga’s euro-denominated term loan. Total UGI International debt outstanding at June 30, 2016, also includes $3.9 million (€3.6 million) of other long-term debt.

In October 2015, Flaga entered into the Flaga Credit Facility Agreement which includes, among other things, a €45.8 million variable-rate term loan facility. In October 2015, Flaga used proceeds from the issuance of the €45.8 million variable-rate term loan to refinance its €19.1 million term loan due October 2016, and its €26.7 million term loan due August 2016. The €45.8 million term loan matures in October 2020.

UGI Utilities. UGI Utilities’ total debt at June 30, 2016, includes $550.0 million of Senior Notes, $100.0 million of Medium-Term Notes and $130.0 million of short-term borrowings. In April 2016, UGI Utilities entered into a Note Purchase Agreement (the “2016 Note Purchase Agreement”) which provides for the private placement of (1) $100.0 million aggregate principal amount of 2.95% Senior Notes due June 30, 2026; (2) $200.0 million aggregate principal amount of 4.12% Senior Notes due September 30, 2046; and (3) $100.0 million aggregate principal amount of 4.12% Senior Notes due October 31, 2046 (collectively, the “Utilities Senior Notes”). On June 30, 2016, UGI Utilities issued $100.0 million aggregate principal amount of 2.95% Senior Notes pursuant to the 2016 Note Purchase Agreement. The net proceeds from the issuance of the 2.95% Senior Notes were used principally to repay short-term borrowings under UGI Utilities’ Credit Agreement in early July 2016. The 4.12% Senior Notes due September 30, 2046 and the 4.12% Senior Notes due October 31, 2046 are expected to be issued in September 2016 and October 2016, respectively. UGI Utilities expects to use the net proceeds from the issuance of the 4.12% Senior Notes to repay UGI Utilities’ currently outstanding $175.0 million principal amount of 5.75% Senior Notes due September 30, 2016 and for general corporate purposes. Because UGI Utilities has the intent and ability to refinance the 5.75% Senior Notes on a long-term basis, the 5.75% Senior Notes have been classified as long-term on the June 30, 2016, Condensed Consolidated Balance Sheet.

On March 31, 2016, concurrent with the pricing of the Senior Notes to be issued under the 2016 Note Purchase Agreement, UGI Utilities settled all of its then-existing IRPA contracts associated with such debt at a loss of $36.0 million. Because these IRPA contracts qualified for and were designated as cash flow hedges, the loss recognized in connection with the settled IRPAs has been recorded in AOCI and will be recognized in interest expense as future interest expense impacts earnings.

Credit Facilities

Additional information related to the Company’s credit agreements can be found in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and Note 5 to the Consolidated Financial Statements in the Company’s 2015 Annual Report. The discussion below provides updates to this information during the nine months ended June 30, 2016.

UGI International. In October 2015, Flaga entered into a €100.8 million Credit Facility Agreement (the “Flaga Credit Facility Agreement”) with a bank. The Flaga Credit Facility Agreement includes a €25 million multi-currency revolving credit facility, a €25 million guarantee facility, a €5 million overdraft facility and the previously mentioned €45.8 million term loan facility. Borrowings under the multi-currency revolving credit facility bear interest at market rates (generally one, three- or nine-month euribor rates) plus margins. The margins on revolving facility borrowings, which range from 1.45% to 3.65%, are based upon the actual currency borrowed and certain consolidated equity, return on assets and debt to EBITDA ratios, as defined in the Flaga Credit Facility Agreement. The Flaga Credit Facility Agreement terminates in October 2020.

Energy Services. In February 2016, Energy Services entered into a Second Amended and Restated Credit Agreement (the "Energy Services Credit Agreement"), as borrower, with a group of lenders providing for borrowings up to $240 million, including a $50 million sublimit for letters of credit. Borrowings under the Energy Services Credit Agreement bear interest at either (i) the Alternate Base Rate plus a margin or (ii) a rate derived from LIBOR (“Adjusted LIBOR”) plus a margin. The Alternate Base Rate (as defined in the Energy Services Credit Agreement) is the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, and (c) the Adjusted LIBOR plus 1%. The margin on such borrowings is currently 2.25%. The Energy Services Credit Agreement requires that Energy Services not exceed ratio of total indebtedness to EBITDA, as defined, of 3.50 to 1.00, and maintain a minimum ratio of EBITDA to interest expense, as defined, of 3.50 to 1.00. The Energy Services Credit Agreement is scheduled to expire in March 2021.

Information about the Company's principal credit agreements (excluding the Energy Services Receivables Facility discussed below) as of June 30, 2016 and 2015, is presented in the table below.

(Millions of dollars or euros)	Total Capacity	Borrowings Outstanding	Letters of Credit and Guarantees Outstanding	Available Capacity
As of June 30, 2016				
AmeriGas Propane	$525.0	$11.4	$63.0	$450.6
UGI France	€60.0	€0.0	€0.0	€60.0
Flaga - Revolving Facility	€25.0	€0.0	€9.6	€15.4
Flaga - Guarantee Facility	€25.0	€0.0	€0.0	€25.0
UGI Utilities	$300.0	$130.0	$2.0	$168.0
Energy Services	$240.0	$0.0	$0.0	$240.0
As of June 30, 2015				
AmeriGas Propane	$525.0	$43.6	$64.7	$416.7
UGI France	€60.0	€0.0	€0.0	€60.0
Flaga	€58.0	€1.5	€20.0	€36.5
UGI Utilities	$300.0	$2.7	$2.0	$295.3
Energy Services	$240.0	$0.0	$0.0	$240.0

The average daily and peak short-term borrowings under the Company's principal credit agreements during the nine months ended June 30, 2016 and 2015 are as follows:

	For the nine months ended June 30, 2016		For the nine months ended June 30, 2015	
(Millions of dollars or euros)	Average	Peak	Average	Peak
AmeriGas Propane	$110.0	$249.0	$136.9	$349.0
Flaga	€0.0	€0.0	€2.9	€3.6
UGI Utilities	$171.6	$232.0	$73.6	$163.6
Energy Services	$12.5	$35.0	$0.2	$7.0

Energy Services also has a receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in October 2016. Energy Services intends to extend the Receivables Facility prior to its scheduled expiration. At June 30, 2016, the outstanding balance of ESFC trade receivables was $40.4 million, and there were no amounts sold to the bank. At June 30, 2015, the outstanding balance of ESFC trade receivables was $42.9 million, of which $20.0 million sold to the bank. Amounts sold to the bank are reflected as short-term borrowings on the Condensed Consolidated Balance Sheets (see Note 7 to condensed consolidated financial statements).

Dividends and Distributions

On July 26, 2016, UGI's Board of Directors approved a quarterly dividend of $0.2375 per common share payable October 1, 2016, to shareholders of record on September 15, 2016. On April 26, 2016, UGI's Board of Directors approved an increase in the quarterly dividend rate on UGI Common Stock to $0.2375 per Common Share, or $0.95 on an annual basis. The dividend rate reflects an approximately 4.4% increase from the previous quarterly rate of $0.2275. The new quarterly dividend rate was effective with the dividend payable on July 1, 2016, to shareholders of record on June 15, 2016.

On July 25, 2016, the General Partner's Board of Directors approved a quarterly distribution of $0.94 per Common Unit payable August 18, 2016, to unitholders of record on August 10, 2016. During the nine months ended June 30, 2016, AmeriGas Partners declared and paid quarterly distributions on all limited partner units at a rate of $0.94 per Common Unit for the quarter ended March 31, 2016, and $0.92 per Common Unit for each of the quarters ended December 31, 2015 and September 30, 2015.

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 and services 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 $863.0 million in the 2016 nine-month period compared to $968.1 million in the 2015 nine-month period. Cash flow from operating activities in the 2016 nine-month period includes the full-period operations of Finagaz acquired on May 29, 2015. Cash flow from operating activities before changes in operating working capital was $879.5 million in the 2016 nine-month period compared to $860.3 million in the prior-year period. The higher cash flow from operating activities before changes in operating working capital reflects the negative effects on cash flow of lower net income (after adjusting net income for the noncash effects on net income of unrealized gains and losses on derivative instruments, and the loss on extinguishment of debt at AmeriGas Partners which is reflected in cash flow from financing activities) more than offset by higher noncash charges for deferred income taxes and depreciation and amortization. Cash used to fund changes in operating working capital totaled $16.5 million in the 2016 nine-month period compared to cash provided by changes in operating working capital of $107.8 million in the prior-year period. The significantly lower cash from changes in accounts receivable, inventories and accounts payable reflects in large part the impact of less significant changes in LPG and natural gas costs and, with respect to changes in accounts receivable and accounts payable, also the lower volumes resulting from the warmer weather. In addition, changes in working capital include net refunds of UGI Utilities purchased gas and electricity costs of $11.5 million in the 2016 nine-month period compared with net cash overcollections of $59.4 million in the prior-year nine-month period.

Investing Activities. Cash flow used by investing activities was $367.1 million in the 2016 nine-month period compared with $775.0 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; investments in investees; and proceeds from sales of assets and businesses. Cash payments for property, plant and equipment were $370.6 million in the 2016 nine-month period compared to $330.4 million in the prior-year period reflecting in large part higher cash capital expenditures at Gas Utility and our expanding UGI International businesses. Cash used for acquisitions of businesses in the 2016 nine-month period includes net cash paid for propane acquisitions at AmeriGas Propane ($36.7 million) and net cash paid for acquisitions of retail LPG businesses at UGI International ($23.6 million). Cash used for acquisitions in the prior-year nine-month period principally reflects the Totalgaz Acquisition.

Financing Activities. Cash flow provided by financing activities was $48.6 million in the 2016 nine-month period compared with cash used by financing activities of $207.3 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 short-term borrowings; dividends and distributions on UGI Common Stock and AmeriGas Partners Common Units; and, from time to time, issuances of UGI and AmeriGas Partners equity instruments. On June 27, 2016, AmeriGas Partners issued $1.35 billion face value of AmeriGas Partners Senior Notes and used a portion of the net proceeds from the issuance to repay $917.1 million principal amount of existing AmeriGas Partners Senior Notes subject to tender offers. In addition, on June 30, 2016, UGI Utilities issued $100 million of Senior Notes and used the net proceeds principally in early July 2016 to repay short-term borrowings. UGI Utilities repaid $72 million of maturing Medium-Term Notes earlier in the 2016 nine-month period principally using short-term borrowings.

The effect of exchange rates on cash during both periods principally reflects the effects on foreign subsidiary cash balances of a weaker euro and British pound sterling.

UTILITY REGULATORY MATTERS

UGI Gas Base Rate Filing. On January 19, 2016, UGI Utilities filed a rate request with the PUC to increase UGI Gas's annual base operating revenues for residential, commercial and industrial customers by $58.6 million. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. UGI Utilities requested that the new gas rates become effective March 19, 2016. The PUC entered an Order dated February 11, 2016, suspending the effective date for the rate increase to no later than October 19, 2016, to allow for investigation and public hearings. On June 30, 2016, a Joint Petition for Approval of Settlement of all issues supported by all active parties was filed with the PUC. Under the terms of the Joint Petition, UGI Utilities will be permitted, effective October 19, 2016, to increase UGI Gas' annual base distribution rates by $27.0 million. The Joint Petition is subject to receipt of a recommended decision by a PUC administrative law judge and an order of the PUC approving the settlement. The Company cannot predict the ultimate outcome of the rate case review process.

UGI Gas Consent Order and Agreement. In May 2016, UGI Gas division executed a Consent Order and Agreement ("UGI Gas-COA") with the DEP with an effective date of October 1, 2016. The UGI Gas-COA will terminate in September 2031 if not extended by the parties. The UGI Gas-COA requires UGI Gas to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which MGP related facilities were operated ("UGI Gas MGP Properties"). Under this agreement, required environmental expenditures related to the UGI Gas MGP Properties are capped at $2.5 million in any calendar year. At June 30, 2016, our estimated accrued liabilities for environmental investigation and remediation costs related to the UGI Gas-COA totaled $43.8 million. UGI Gas has recorded associated regulatory assets for these costs because recovery of these costs from customers is probable (see Note 9 to condensed consolidated financial statements).

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 LPG 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 economically hedge forecasted purchases of LPG are generally settled at expiration of the contract. In addition, our UGI International businesses economically hedge a portion of their anticipated U.S. dollar-denominated LPG product purchases through the use of forward foreign currency 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, 2016, the fair values of Gas Utility's natural gas futures and option contracts were net gains of $5.5 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 FTRs and forward electricity purchase contracts, associated with our Electric Utility operations. At June 30, 2016, all of our Electric Utility's forward electricity purchase contracts were subject to the NPNS exception. At June 30, 2016, 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 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 or operating expenses.

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 and over-the-counter natural gas futures and forward contracts, ICE natural gas basis swap contracts, and electricity futures and forward contracts. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to economically hedge the price of 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 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 near-term 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, 2016 (excluding those Gas Utility and Electric Utility commodity derivative instruments that are refundable to, or recoverable from, customers) was a loss of $6.3 million. A hypothetical 10% adverse change in the market price of LPG, gasoline, natural gas, electricity and electricity transmission congestion charges would increase such loss by approximately $57.0 million at June 30, 2016.

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, 2016, includes our short-term borrowings and France SAS's and Flaga's variable-rate term loans. These debt agreements have interest rates that are generally indexed to short-term market interest rates. France SAS and Flaga, through the use of pay-fixed receive-variable interest rate swaps, have fixed the underlying euribor interest rates on their euro-denominated term loans through all, or a substantial portion of, the periods such debt is outstanding. In addition, Flaga's U.S. dollar-denominated loans have 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, 2016, combined borrowings outstanding under variable-rate debt agreements, excluding France SAS's and Flaga's effectively fixed-rate debt, totaled $144.0 million.

Long-term debt associated with our domestic businesses is typically issued at fixed rates of interest based upon market rates for debt with 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 IRPAs.

The fair value of unsettled interest rate risk sensitive derivative instruments held at June 30, 2016 (including pay-fixed, receive-variable interest rate swaps) was a loss of $3.8 million. A 50 basis point adverse change in the three-month euribor rate and three-month LIBOR would result in a decrease in fair value of approximately $3.1 million.

Foreign Currency Exchange Rate Risk

Our primary currency exchange rate risk is associated with the U.S. dollar versus the euro and, to a lesser extent, the U.S. dollar versus the British pound sterling. 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, 2016, 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 would reduce their aggregate net book value at June 30, 2016, by approximately $110.0 million, which amount would be reflected in other comprehensive income.

In addition, in order to reduce volatility related to our foreign LPG operations, we hedge a portion of their anticipated U.S. dollar-denominated LPG product purchases primarily during the months of October through March through the use of forward foreign exchange contracts.

The fair value of unsettled foreign currency exchange rate risk sensitive derivative instruments held at June 30, 2016, including the fair value of Flaga's cross-currency swap described above, was a gain of $18.1 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 $23.9 million.

Derivative Instrument Credit Risk

We are exposed to risk of loss in the event of nonperformance by our derivative instrument counterparties. Our derivative 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 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 commodity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2016 and 2015, restricted cash in brokerage accounts totaled $9.6 million and $45.2 million, respectively. Although we have concentrations of credit risk associated with derivative instruments, the maximum amount of loss, based upon the gross fair values of the derivative instruments, we would incur if these counterparties failed to perform according to the terms of their contracts was not material at June 30, 2016. 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, 2016, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

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 or submitted 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.

UGI CORPORATION AND SUBSIDIARIES

PART II OTHER INFORMATION

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, 2015, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing the Company. Other unknown or unpredictable factors could also have material adverse effects on future results.

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**
4.1	Indenture, dated as of June 27, 2016, among AmeriGas Partners, L.P., AmeriGas Finance Corp., and U.S. Bank National Association, as trustee.	AmeriGas Partners, L.P.	Form 8-K (6/27/16)	4.1
4.2	First Supplemental Indenture, dated as of June 27, 2016, among AmeriGas Partners, L.P., AmeriGas Finance Corp., and U.S. Bank National Association, as trustee.	AmeriGas Partners, L.P.	Form 8-K (6/27/16)	4.2
10.1	Amendment to Contingent Residual Support Agreement dated June 20, 2016, among Energy Transfer Partners, L.P., AmeriGas Finance LLC, AmeriGas Finance Corp., AmeriGas Partners, L.P., and for certain limited purposes only, UGI Corporation.	AmeriGas Partners, L.P.	Form 8-K (6/20/16)	10.1
10.2	Amendment No. 1 dated as of June 20, 2016 to Amended and Restated Credit Agreement dated June 18, 2014 by and among AmeriGas Propane, L.P., as Borrower, AmeriGas Propane, Inc., as Guarantor, Wells Fargo Bank, National Association, as Administrative Agent, Swingline Lender, and Issuing Lender, Wells Fargo Securities, LLC, as Sole Lead Arranger and Sole Book Manager, Credit Suisse, AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Citizens Bank of Pennsylvania, PNC Bank, National Association, Branch Banking and Trust Company, Citibank, N.A., The Bank of New York Mellon, Bank of America, N.A., Manufactures and Traders Trust Company, Santander Bank, N.A., TD Bank, N.A. and the other financial institutions from time to time party thereto.	AmeriGas Partners, L.P.	Form 8-K (6/20/16)	10.2
31.1	Certification by the Chief Executive Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2016, 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, 2016, 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, 2016, 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			

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 5, 2016	By:	/s/ Kirk R. Oliver Kirk R. Oliver Chief Financial Officer
Date: August 5, 2016	By:	/s/ Marie-Dominique Ortiz-Landazabal Marie-Dominique Ortiz-Landazabal Vice President - Accounting and Financial Control and Chief Accounting Officer

Table of Contents

UGI CORPORATION AND SUBSIDIARIES

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, 2016, 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, 2016, 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, 2016, 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

EXHIBIT 31.1

CERTIFICATION

I, John L. Walsh, certify that:

1. I have reviewed this periodic report on Form 10-Q of UGI Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2016

/s/ John L. Walsh

John L. Walsh
President and Chief Executive Officer of
UGI Corporation

EXHIBIT 31.2

CERTIFICATION

I, Kirk R. Oliver, certify that:

1. I have reviewed this periodic report on Form 10-Q of UGI Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2016

/s/ Kirk R. Oliver

Kirk R. Oliver

Chief Financial Officer of UGI Corporation

Certification by the Chief Executive Officer and Chief Financial Officer
Relating to a Periodic Report Containing Financial Statements

I, John L. Walsh, Chief Executive Officer, and I, Kirk R. Oliver, Chief Financial Officer, of UGI Corporation, a Pennsylvania corporation (the "Company"), hereby certify that to our knowledge:

(1) The Company's periodic report on Form 10-Q for the period ended June 30, 2016 (the "Form 10-Q") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

CHIEF EXECUTIVE OFFICER	CHIEF FINANCIAL OFFICER
/s/ John L. Walsh	/s/ Kirk R. Oliver
John L. Walsh	Kirk R. Oliver
Date: August 5, 2016	Date: August 5, 2016