UGI CORP /PA/
Form 10-Q
August 07, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ________ to ________
Commission file number 1-11071
UGI CORPORATION
(Exact name of registrant as specified in its charter)

Pennsylvania (State or other jurisdiction of incorporation or organization)	23-2668356 (I.R.S. Employer Identification No.)
460 North Gulph Road, King of Prussia, PA (Address of principal executive offices)	19406 (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 ý 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 ý 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	ý	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 ý
At July 31, 2015, there were 172,778,018 shares of UGI Corporation Common Stock, without par value, outstanding.

UGI CORPORATION AND SUBSIDIARIES
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UGI CORPORATION AND SUBSIDIARIES

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

	June 30, 2015	September 30, 2014	June 30, 2014
ASSETS			
Current assets:			
Cash and cash equivalents	$385.9	$419.5	$438.4
Restricted cash	45.2	16.6	5.9
Accounts receivable (less allowances for doubtful accounts of $40.3, $39.1 and $52.5, respectively)	728.2	684.7	785.4
Accrued utility revenues	7.7	14.3	8.0
Inventories	208.7	423.0	332.0
Deferred income taxes	71.6	10.1	9.1
Utility regulatory assets	2.8	13.2	9.4
Derivative instruments	27.3	14.5	12.4
Prepaid expenses and other current assets	80.7	67.1	38.3
Total current assets	1,558.1	1,663.0	1,638.9
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $2,773.6, $2,633.0 and $2,702.3, respectively)	4,923.7	4,543.7	4,543.4
Goodwill	2,927.7	2,833.4	2,885.1
Intangible assets, net	628.5	576.4	590.3
Derivative instruments	15.6	12.5	1.3
Other assets	466.4	464.0	418.7
Total assets	$10,520.0	$10,093.0	$10,077.7
LIABILITIES AND EQUITY			
Current liabilities:			
Current maturities of long-term debt	$83.3	$77.2	$78.4
Short-term borrowings	68.0	210.8	96.5
Accounts payable	356.8	459.8	403.8
Derivative instruments	109.6	40.2	26.2
Other current liabilities	721.7	642.9	609.3
Total current liabilities	1,339.4	1,430.9	1,214.2
Long-term debt	3,628.3	3,433.6	3,477.8
Deferred income taxes	1,162.9	1,005.1	986.2
Deferred investment tax credits	3.7	3.9	4.0
Derivative instruments	25.7	16.6	16.9
Other noncurrent liabilities	624.4	539.7	497.8
Total liabilities	6,784.4	6,429.8	6,196.9
Commitments and contingencies (Note 9)			
Equity:			
UGI Corporation stockholders’ equity:			
UGI Common Stock, without par value (authorized—450,000,000 shares; issued—173,806,991, 173,770,641 and 173,746,041 shares, respectively)	1,208.4	1,215.6	1,216.0
Retained earnings	1,685.3	1,509.4	1,566.7
Accumulated other comprehensive (loss) income	(112.2)	(21.2)	25.4
Treasury stock, at cost	(33.0)	(44.7)	(37.1)

Total UGI Corporation stockholders’ equity	2,748.5	2,659.1	2,771.0
Noncontrolling interests, principally in AmeriGas Partners	987.1	1,004.1	1,109.8
Total equity	3,735.6	3,663.2	3,880.8
Total liabilities and equity	$10,520.0	$10,093.0	$10,077.7

See accompanying notes to condensed consolidated financial statements.

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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,	
	2015	2014	2015	2014
Revenues	$1,148.1	$1,486.7	$5,608.3	$6,965.9
Costs and expenses:				
Cost of sales (excluding depreciation shown below)	586.4	926.5	3,196.4	4,357.7
Operating and administrative expenses	419.8	415.9	1,322.1	1,339.4
Utility taxes other than income taxes	3.7	3.7	12.6	12.7
Depreciation	77.2	74.6	226.8	230.0
Amortization	15.3	15.4	44.7	41.7
Other operating income, net	(10.4)	(12.1)	(35.8)	(30.6)
	1,092.0	1,424.0	4,766.8	5,950.9
Operating income	56.1	62.7	841.5	1,015.0
Loss from equity investees	—	(0.1)	(1.1)	(0.1)
Interest expense	(67.5)	(60.1)	(184.7)	(178.9)
(Loss) income before income taxes	(11.4)	2.5	655.7	836.0
Income tax expense	(4.5)	(15.2)	(189.2)	(243.4)
Net (loss) income	(15.9)	(12.7)	466.5	592.6
Add net loss (deduct net income) attributable to noncontrolling interests, principally in AmeriGas Partners	25.5	33.3	(176.3)	(235.6)
Net income attributable to UGI Corporation	$9.6	$20.6	$290.2	$357.0
Earnings per common share attributable to UGI Corporation stockholders:				
Basic	$0.06	$0.12	$1.68	$2.07
Diluted	$0.05	$0.12	$1.65	$2.04
Average common shares outstanding (thousands):				
Basic	173,136	173,055	173,060	172,682
Diluted	175,580	175,572	175,665	175,097
Dividends declared per common share	$0.2275	$0.1967	$0.6625	$0.5733

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2015	2014	2015	2014
Net (loss) income	$(15.9)	$(12.7)	$466.5	$592.6
Other comprehensive income (loss):				
Net (losses) gains on derivative instruments (net of tax of $2.4, $0.6, $(11.9) and $(6.5), respectively)	(4.8)	(0.6)	23.1	46.2
Reclassifications of net losses (gains) on derivative instruments (net of tax of $(1.9), $(1.3), $(2.3) and $4.0, respectively)	0.5	(1.5)	0.7	(46.7)
Foreign currency adjustments (net of tax of $(55.3), $0.0, $(4.7) and $(3.1), respectively)	(23.0)	(0.2)	(118.0)	11.5
Benefit plans (net of tax of $(0.1), $(0.2), $(0.7) and $(0.2), respectively)	0.4	0.2	1.4	0.8
Other comprehensive (loss) income	(26.9)	(2.1)	(92.8)	11.8
Comprehensive (loss) income	(42.8)	(14.8)	373.7	604.4
Add comprehensive loss (deduct comprehensive income) attributable to noncontrolling interests, principally in AmeriGas Partners	25.6	36.5	(174.5)	(230.4)
Comprehensive (loss) income attributable to UGI Corporation	$(17.2)	$21.7	$199.2	$374.0

See accompanying notes to condensed consolidated financial statements.

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

	Nine Months Ended June 30,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$466.5	$592.6
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	271.5	271.7
Deferred income tax (benefit) expense, net	(39.9)	21.2
Provision for uncollectible accounts	26.2	38.2
Unrealized losses on derivative instruments	109.5	3.1
Other, net	26.5	(4.9)
Net change in:		
Accounts receivable and accrued utility revenues	54.4	(56.4)
Inventories	211.0	34.8
Utility deferred fuel and power costs, net of changes in unsettled derivatives	59.4	(17.6)
Accounts payable	(171.2)	(40.8)
Other current assets	(3.7)	11.2
Other current liabilities	(42.1)	5.0
Net cash provided by operating activities	968.1	858.1
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(330.4)	(325.5)
Acquisitions of businesses, net of cash acquired	(428.2)	(23.3)
(Increase) decrease in restricted cash	(28.6)	2.4
Other, net	12.2	9.0
Net cash used by investing activities	(775.0)	(337.4)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(114.3)	(98.6)
Distributions on AmeriGas Partners publicly held Common Units	(185.3)	(176.9)
Issuances of debt	652.6	175.0
Repayments of debt	(406.4)	(236.8)
Decrease in short-term borrowings	(154.2)	(74.6)
Receivables Facility net borrowings (repayments)	12.5	(57.0)
Issuances of UGI Common Stock	10.3	7.0
Repurchases of UGI Common Stock	(17.3)	(21.4)
Other	(5.2)	7.9
Net cash used by financing activities	(207.3)	(475.4)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(19.4)	3.8
Cash and cash equivalents (decrease) increase	$(33.6)	$49.1
Cash and cash equivalents:		
End of period	$385.9	$438.4
Beginning of period	419.5	389.3
(Decrease) increase	$(33.6)	$49.1

See accompanying notes to condensed consolidated financial statements.

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UGI CORPORATION AND SUBSIDIARIES

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

	Nine Months Ended June 30, 2015	2014
Common stock, without par value		
Balance, beginning of period	$1,215.6	$1,208.1
Common Stock issued in connection with employee and director plans (including (losses) gains on treasury stock transactions), net of tax withheld	(18.6)	(9.6)
Excess tax benefits realized on equity-based compensation	6.3	8.4
Equity-based compensation expense	11.7	9.1
Loss from acquisition of noncontrolling interests through business combination	(6.6)	—
Balance, end of period	$1,208.4	$1,216.0
Retained earnings		
Balance, beginning of period	$1,509.4	$1,308.3
Net income attributable to UGI Corporation	290.2	357.0
Cash dividends on Common Stock	(114.3)	(98.6)
Balance, end of period	$1,685.3	$1,566.7
Accumulated other comprehensive income (loss)		
Balance, beginning of period	$(21.2)	$8.4
Net gains on derivative instruments, net of tax	23.1	12.3
Reclassification of net losses (gains) on derivative instruments, net of tax	2.5	(7.6)
Benefit plans, net of tax	1.4	0.8
Foreign currency, net of tax	(118.0)	11.5
Balance, end of period	$(112.2)	$25.4
Treasury stock		
Balance, beginning of period	$(44.7)	$(32.3)
Common stock issued in connection with employee and director plans, net of tax withheld	33.2	46.7
Repurchases of Common Stock	(17.3)	(21.4)
Reacquired common stock - employee and director plans	(4.2)	(30.1)
Balance, end of period	$(33.0)	$(37.1)
Total UGI Corporation stockholders' equity	$2,748.5	$2,771.0
Noncontrolling interests		
Balance, beginning of period	$1,004.1	$1,055.4
Net income attributable to noncontrolling interests, principally in AmeriGas Partners	176.3	235.6
Net gains on derivative instruments	—	33.9
Reclassification of net gains on derivative instruments	(1.8)	(39.1)
Dividends and distributions	(185.8)	(176.9)
Change in noncontrolling interests as a result of business combination	(5.2)	—
Other	(0.5)	0.9
Balance, end of period	$987.1	$1,109.8
Total equity	$3,735.6	$3,880.8

See accompanying notes to condensed consolidated financial statements.

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(unaudited)
(Millions of dollars and euros, 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 and China. 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, 2015, 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 23,756,882 AmeriGas Partners Common Units ("Common Units"). The remaining 73.7% interest in AmeriGas Partners comprises 69,132,661 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, 2014 (the "Company's 2014 Annual Report"). Incentive distributions received by the General Partner during the nine months ended June 30, 2015 and 2014 were $21.7 and $17.3, respectively.

Our wholly owned subsidiary, UGI Enterprises, Inc. ("Enterprises"), through subsidiaries, conducts (1) an LPG distribution business in France, Belgium, the Netherlands and Luxembourg ("Antargaz"); (2) an LPG distribution business in central, northern and eastern Europe ("Flaga"); (3) an LPG distribution business in the United Kingdom ("AvantiGas"); and (4) an LPG distribution business in the Nantong region of China. We refer to our foreign LPG operations collectively as "UGI International." On May 29, 2015, UGI France (formerly Bordeaux Holding), an indirect wholly owned subsidiary of UGI, purchased all of the outstanding shares of Totalgaz (referred to as Finagaz after the acquisition), a retail distributor of LPG in France. The assets and liabilities and results of operations of Finagaz are included in our Antargaz reportable segment (see Notes 14 and 15).

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.

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."

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

Note 2 — Summary of Significant Accounting Policies

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

The accompanying condensed consolidated financial statements are unaudited and have been prepared in accordance with the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). They include all adjustments that we consider necessary for a fair statement of the results for the interim periods presented. Such adjustments consisted only of normal recurring items unless otherwise disclosed. The September 30, 2014, 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 2014 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 shareholders reflect the weighted-average number of common shares outstanding. Diluted earnings per share attributable to UGI Corporation include the effects of dilutive stock options and common stock awards.

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2015	2014	2015	2014
Denominator (thousands of shares):				
Average common shares outstanding for basic computation	173,136	173,055	173,060	172,682
Incremental shares issuable for stock options and awards	2,444	2,517	2,605	2,415
Average common shares outstanding for diluted computation	175,580	175,572	175,665	175,097

Derivative Instruments. Derivative instruments are reported in 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 or net investment hedges. For cash flow hedges, changes in the fair values of the derivative instruments are recorded in accumulated other

comprehensive income (“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 the forecasted transaction is determined to be no longer probable. 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 certain commodity derivative instruments used by Gas Utility and Electric Utility 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

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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. For additional information on our derivative instruments, 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 a $57.8 decrease to 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 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. The Company has evaluated the effects of the errors, both qualitatively and quantitatively, and concluded that they did not have a material impact on any prior annual or quarterly consolidated financial statement. The Company also evaluated and concluded that the impact of recording the cumulative effect of the correction of the error as of April 1, 2015 (the beginning of the three-month period ended June 30, 2015) is not material to the financial statements for the three or nine months ended June 30, 2015 and is not expected to be material to the full year results for Fiscal 2015.
The impact to other comprehensive income for the three and nine months ended June 30, 2015 resulting from the correction of these errors is as follows:

	Three Months Ended June 30, 2015	Nine Months Ended June 30, 2015
Reported other comprehensive loss	$(26.9)	$(92.8)
Correction of error in deferred taxes related to prior periods	57.8	10.7
Other comprehensive income (loss) excluding impact of correction	$30.9	$(82.1)

Note 3 — Accounting Changes

Accounting Standards Not Yet Adopted

Measurement of Inventory. In July 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2015-11, "Simplifying the Measurement of Inventory." This ASU amends existing guidance to require inventory to be measured at the lower of cost or net realizable value. Entities will continue to apply their existing impairment models to inventories that are accounted for using “last-in, first-out” and the “retail inventory” methods. The amendments in this ASU are effective for annual periods beginning after December 15, 2016 (Fiscal 2018) including interim periods within those

fiscal years. Early adoption is permitted. Entities will apply the new guidance prospectively after the date of adoption. The Company is in the process of assessing the impact on its financial statements, if any, from the adoption of the new guidance.
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. Early adoption is permitted. Entities will apply the new guidance retrospectively to all periods presented. The Company expects to adopt the new guidance in the fourth quarter of Fiscal 2015. The adoption of the new guidance is not expected to have a material impact on the Company’s financial statements.

Consolidation. In February 2015, the FASB issued ASU No. 2015-02, “Amendments to the Consolidation Analysis.” This ASU provides new guidance regarding whether a reporting entity should consolidate certain types of legal entities. Among other things, the new guidance modifies the evaluation of whether limited partnerships and similar entities are variable interest entities (“VIEs”) or voting interest entities, and also eliminates the presumption that a general partner should consolidate a limited partnership. The new guidance also affects the consolidation analysis of reporting entities that are involved with VIEs including those that have fee arrangements and related party relationships. The new guidance is effective for the Company beginning in Fiscal 2017. Early adoption is permitted. The Company is in the process of assessing the impact on its financial statements, if any, from the adoption of the new guidance.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers.” This ASU supersedes the revenue recognition requirements in Accounting Standards Codification (“ASC”) 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 company expects to be entitled in exchange for those goods or services. This standard is effective for the Company for interim and annual periods beginning October 1, 2017 (Fiscal 2018) and allows for either full retrospective adoption or modified retrospective adoption. On July 9, 2015, the FASB voted to delay the effective date by one year. We have not yet selected a transition method and are currently evaluating the impact of adopting this guidance on our consolidated financial statements.

Note 4 — Inventories

Inventories comprise the following:

	June 30, 2015	September 30, 2014	June 30, 2014
Non-utility LPG and natural gas	$124.6	$283.6	$222.6
Gas Utility natural gas	19.2	82.7	45.7
Materials, supplies and other	64.9	56.7	63.7
Total inventories	$208.7	$423.0	$332.0

At June 30, 2015, UGI Utilities is a party to three 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, 2015, UGI Utilities has SCAAs with Energy Services and a non-affiliate. The carrying value of gas storage inventories released under the SCAAs with non-affiliates at June 30, 2015, September 30, 2014 and June 30, 2014, comprising 1.9 billion cubic feet ("bcf"), 3.9 bcf and 2.1 bcf of natural gas, was $4.5, $16.8 and $8.9, respectively.

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Note 5 — Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	June 30, 2015	September 30, 2014	June 30, 2014
Goodwill (not subject to amortization)	$2,927.7	$2,833.4	$2,885.1
Intangible assets:			
Customer relationships, noncompete agreements and other	$761.9	$712.0	$717.3
Accumulated amortization	(268.4)	(263.8)	(259.0)
Intangible assets, net (definite-lived)	493.5	448.2	458.3
Trademarks and tradenames (indefinite-lived)	135.0	128.2	132.0
Total intangible assets, net	$628.5	$576.4	$590.3

The increase in goodwill and intangible assets at June 30, 2015, reflects the preliminary purchase price allocation of Totalgaz to these assets (see Note 15) partially offset by the effects of currency translation. Amortization expense of intangible assets was $13.1 and $38.1 for the three and nine months ended June 30, 2015, respectively. Amortization expense of intangible assets was $13.3 and $35.5 for the three and nine months ended June 30, 2014, respectively. Amortization expense included in cost of sales in the Condensed Consolidated Statements of Income is not material. The estimated aggregate amortization expense of intangible assets for the remainder of Fiscal 2015 and for the next four fiscal years is as follows: remainder of Fiscal 2015 — $13.7; Fiscal 2016 — $50.1; Fiscal 2017 — $43.9; Fiscal 2018 — $42.2; Fiscal 2019 — $40.6.

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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 2014 Annual Report. UGI Utilities does not recover a rate of return on its regulatory assets. The following regulatory assets and liabilities associated with Utilities are included in our accompanying Condensed Consolidated Balance Sheets:

	June 30, 2015	September 30, 2014	June 30, 2014
Regulatory assets (a):			
Income taxes recoverable	$111.8	$110.7	$107.2
Underfunded pension and postretirement plans	103.2	110.1	89.2
Environmental costs	14.5	14.6	14.6
Deferred fuel and power costs	—	11.8	9.4
Removal costs, net	19.6	16.8	15.6
Other	5.1	4.2	6.6
Total regulatory assets	$254.2	$268.2	$242.6
Regulatory liabilities (a):			
Postretirement benefits	$19.6	$18.6	$17.5
Environmental overcollections	—	0.3	1.6
Deferred fuel and power refunds	45.6	0.3	—
State tax benefits—distribution system repairs	10.9	10.1	9.3
Other	1.4	3.2	1.9
Total regulatory liabilities	$77.5	$32.5	$30.3

(a) Noncurrent regulatory assets are recorded in other assets and regulatory liabilities are recorded in other current and other noncurrent liabilities in the Condensed Consolidated Balance Sheets.

Deferred fuel and power—costs and 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, 2015, September 30, 2014 and June 30, 2014 were $(0.7), $(1.4) and $0.7, respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Previous to March 1, 2015, we did not designate these purchase contracts as an NPNS election under GAAP. Therefore, we recognized 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 June 30, 2015, September 30, 2014, and June 30, 2014, the fair values of Electric Utility's electricity supply contracts were gains (losses) of $(1.4), $0.3 and $0.8, respectively. These amounts are reflected in current and noncurrent derivative

assets and current and noncurrent derivative liabilities on the Condensed Consolidated Balance Sheets with equal and offsetting amounts reflected in deferred fuel and power costs and refunds in the table above. 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 (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

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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, 2015, September 30, 2014, and June 30, 2014, were not material.

Distribution System Improvement Charge. On April 14, 2012, legislation enabling gas and electric utilities in Pennsylvania to seek to charge recovery of eligible capital investment in distribution system infrastructure improvement projects became effective. 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, for up to five percent of distribution rates. 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. PNG and CPG began seeking permission to include a DSIC in their tariffs in 2014, while UGI Gas has not had a general rate filing within the required time period to be eligible. Beginning on April 1, 2015, PNG was able to include a DSIC charge in its tariff rate in accordance with a PUC order. The impact of the DSIC charge at PNG did not have a material effect on Gas Utility results of operations.

Note 7 — Energy Services Accounts Receivable Securitization Facility

Energy Services has a receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in October 2015. The Receivables Facility provides Energy Services with the ability to borrow up to $150 of eligible receivables during the period November to May and up to $75 of eligible receivables during the period June to 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 or the commercial paper conduit. The Company records interest expense on amounts owed to the bank or the commercial paper conduit. Energy Services continues to service, administer and collect trade receivables on behalf of the bank or commercial paper issuer, as applicable.

During the nine months ended June 30, 2015 and 2014, Energy Services transferred trade receivables to ESFC totaling $873.4 and $1,073.1, respectively. During the nine months ended June 30, 2015 and 2014, ESFC sold an aggregate $272.5 and $196.0, respectively, of undivided interests in its trade receivables 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. At June 30, 2014, the outstanding balance of ESFC receivables was $57.7 and there were no amounts sold to the bank. Losses on sales of receivables to the bank during the nine months ended June 30, 2015 and 2014, which are included in interest expense on the Condensed Consolidated Statements of Income, were not material.

Note 8 — Debt

On March 27, 2015, UGI Utilities entered into an unsecured revolving credit agreement (the “UGI Utilities 2015 Credit Agreement”) with a group of banks providing for borrowings up to $300 (including a $100 sublimit for letters of credit). Concurrently with entering into the UGI Utilities 2015 Credit Agreement, UGI Utilities terminated its then-existing $300 revolving credit agreement dated as of May 25, 2011. Under the UGI Utilities 2015 Credit Agreement, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks’ prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.75% and is based upon the credit ratings of certain indebtedness of UGI Utilities. The UGI Utilities 2015 Credit Agreement requires UGI Utilities not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.0. The UGI Utilities 2015 Credit Agreement is currently scheduled to expire in March 2016, but may be extended by UGI Utilities to March 2020 if on or before March 25, 2016, UGI Utilities receives approval for the UGI Utilities 2015 Credit Agreement by the PUC. UGI Utilities filed to obtain such approval on June 30, 2015.

On May 29, 2015, UGI France, an indirect wholly owned subsidiary of UGI, borrowed €600 ($659.6) under its Senior Facilities Agreement with a consortium of banks (the “2015 Senior Facilities Agreement”). UGI France entered into the 2015 Senior Facilities Agreement on April 30, 2015, in anticipation of its then-pending acquisition of Totalgaz, which was consummated on May 29,

2015 (see Note 15). The 2015 Senior Facilities Agreement consists of a €600 variable-rate term loan and a €60 revolving credit facility. The term loan proceeds were used (1) to fund a portion of the acquisition of Totalgaz, including related fees and expenses; (2) to make a capital contribution from UGI France to its wholly owned subsidiary, AGZ Holding, to prepay €342 principal amount, plus accrued interest, outstanding under Antargaz' 2011 Senior Facilities Agreement due March 2016 (the "2011 Senior Facilities Agreement"); (3) to settle Antargaz' existing pay-fixed, receive-variable interest rate swaps associated with the 2011 Senior Facilities Agreement; and (4) for general corporate purposes. As a result of prepaying the term loan outstanding under the 2011 Senior Facilities Agreement and concurrently settling the associated pay-fixed, receive-variable interest rate swaps, we 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.

Borrowings under the 2015 Senior Facilities Agreement €600 term loan and the €60 revolving credit facility bear interest at rates per annum comprising the aggregate of the applicable margin and the associated euribor rate, which euribor rate has a floor of 0.0%. The margin on such borrowings (which ranges from 1.60% to 2.70% for the term loan, and 1.45% to 2.55% for the revolving credit facility) are dependent upon the ratio of UGI France's consolidated total net debt to earnings before interest expense, income taxes, depreciation, and amortization ("EBITDA"), each as defined in the 2015 Senior Facilities Agreement. Through March 31, 2016, the margin has been set at 2.50%. UGI France has entered into pay-fixed, receive-variable interest rate swaps through April 30, 2019, to generally fix the underlying euribor rate at 0.18% (assuming such underlying euribor rate is not less than 0.0%). At June 30, 2015, the effective interest rate on the 2015 Senior Facilities Agreement term loan was 2.68%. At June 30, 2015, there were no borrowings under the revolving credit facility.

Principal amounts outstanding under the 2015 Senior Facilities Agreement term loan are due as follows: €60 due April 30, 2018; €60 due April 30, 2019; and €480 due April 30, 2020. The 2015 Senior Facilities Agreement restricts the ability of UGI France to, among other things, incur additional indebtedness, make investments, incur liens, and effect mergers, consolidations and sales of assets, and requires UGI France and its consolidated subsidiaries to maintain a ratio of total net debt to EBITDA, each as defined in the 2015 Senior Facilities Agreement, that shall not exceed (a) 3.75 to 1.00 from the closing date of the Totalgaz acquisition to September 30, 2015, and (b) 3.50 to 1.00 from October 1, 2015, to the final maturity date. UGI France will generally be permitted to make restricted payments, such as dividends, if no event of default exists or would exist upon payment of such dividend.

Note 9 — Commitments and Contingencies

Environmental Matters

UGI Utilities

CPG is party to a Consent Order and Agreement ("CPG-COA") with the Pennsylvania Department of Environmental Protection ("DEP") requiring CPG to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which manufactured gas plant ("MGP") related facilities were operated ("CPG MGP Properties") and to plug a minimum number of non-producing natural gas wells per year. In addition, PNG is a party to a Multi-Site Remediation Consent Order and Agreement ("PNG-COA") with the DEP. The PNG-COA requires PNG to perform annually a specified level of activities associated with environmental investigation and remediation work at certain properties on which MGP-related facilities were operated ("PNG MGP Properties"). Under these agreements, environmental expenditures relating to the CPG MGP Properties and the PNG MGP Properties are capped at $1.8 and $1.1, respectively, in any calendar year. The CPG-COA is scheduled to terminate at the end of 2018. The PNG-COA terminates in 2019 but may be terminated by either party effective at the

end of any two-year period beginning with the original effective date in March 2004. At June 30, 2015 and 2014, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $9.6 and $11.4, respectively. We have recorded associated regulatory assets for these costs because recovery of these costs from customers is probable.

From the late 1800s through the mid-1900s, UGI Utilities and its former subsidiaries owned and operated a number of MGPs prior to the general availability of natural gas. Some constituents of coal tars and other residues of the manufactured gas process are today considered hazardous substances under the Superfund Law and may be present on the sites of former MGPs. Between 1882 and 1953, UGI Utilities owned the stock of subsidiary gas companies in Pennsylvania and elsewhere and also operated the businesses of some gas companies under agreement. Pursuant to the requirements of the Public Utility Holding Company Act of 1935, by the early 1950s UGI Utilities divested all of its utility operations other than certain Pennsylvania operations, including those which now constitute UGI Gas and Electric Utility.

UGI Utilities does not expect its costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to its results of operations because (1) UGI Gas is currently permitted to include in rates, through future base rate proceedings, a five-year average of such prudently incurred remediation costs, and (2) CPG and PNG are currently receiving regulatory recovery of estimated environmental investigation and remediation costs associated with Pennsylvania sites. At June 30, 2015, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas was material.

From time to time, UGI Utilities is notified of sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by UGI Utilities or owned or operated by its former subsidiaries. Such parties generally investigate the extent of environmental contamination or perform environmental remediation. Management believes that under applicable law UGI Utilities should not be liable in those instances in which a former subsidiary owned or operated an MGP. There could be, however, significant future costs of an uncertain amount associated with environmental damage caused by MGPs outside Pennsylvania that UGI Utilities directly operated, or that were owned or operated by former subsidiaries of UGI Utilities if a court were to conclude that (1) the subsidiary's separate corporate form should be disregarded, or (2) UGI Utilities should be considered to have been an operator because of its conduct with respect to its subsidiary's MGP.

Other Matters

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 its common customer, Walmart Stores, Inc., to accept that fill reduction, resulting in increased cylinder costs to retailers and end-user customers in violation of federal and certain state antitrust laws. The claims seek treble damages, injunctive relief, attorneys' fees and costs on behalf of the putative classes. 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 have filed a notice of appeal with the United States Court of Appeals for the Eighth Circuit; other procedural responses may be available to the indirect customers. We are unable to reasonably estimate the impact, if any, arising from such litigation. We believe we have strong defenses to the claims and intend to vigorously defend against them.

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

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, Antargaz employees are covered by certain defined benefit pension and postretirement plans.

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

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended June 30,	2015	2014	2015	2014
Service cost	$2.5	$2.3	$0.2	$0.1
Interest cost	6.2	6.5	0.2	0.2
Expected return on assets	(7.9)	(7.3)	(0.2)	(0.1)
Amortization of:				
Prior service cost (benefit)	—	0.1	(0.2)	(0.1)
Actuarial loss	2.5	1.9	0.1	—
Net benefit cost	3.3	3.5	0.1	0.1
Change in associated regulatory liabilities	—	—	0.9	0.9
Net expense	$3.3	$3.5	$1.0	$1.0

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended June 30,	2015	2014	2015	2014
Service cost	$7.4	$7.0	$0.5	$0.4
Interest cost	18.8	19.4	0.6	0.7
Expected return on assets	(23.8)	(22.0)	(0.5)	(0.4)
Amortization of:				
Prior service cost (benefit)	0.2	0.2	(0.4)	(0.4)
Actuarial loss	7.5	5.7	0.1	0.1
Net benefit cost	10.1	10.3	0.3	0.4
Change in associated regulatory liabilities	—	—	2.8	2.7
Net expense	$10.1	$10.3	$3.1	$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, 2015 and 2014, the Company made cash contributions to the U.S. Pension Plan of $8.4 and $11.0, respectively. The Company expects to make additional discretionary cash contributions of approximately $2.8 to the U.S. Pension Plan during the remainder of Fiscal 2015.

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, 2015 and 2014.

We also sponsor unfunded and non-qualified supplemental executive defined benefit retirement plans ("Supplemental Defined Benefit Plans"). We recorded pre-tax expense associated with these plans of $0.7 and $0.6 in the three months ended June 30, 2015 and 2014, respectively. We recorded pre-tax expense associated with these plans of $2.0 and $2.3 in the nine months ended June 30, 2015 and 2014, respectively.

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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, 2015, September 30, 2014 and June 30, 2014:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
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
September 30, 2014:				
Derivative instruments:				
Assets:				
Commodity contracts	$10.6	$19.8	$—	$30.4
Foreign currency contracts	$—	$12.8	$—	$12.8
Interest rate contracts	$—	$0.1	$—	$0.1
Cross-currency swaps	$—	$2.1	$—	$2.1
Liabilities:				
Commodity contracts	$(21.2)	$(32.9)	$—	$(54.1)
Foreign currency contracts	$—	$(0.1)	$—	$(0.1)
Interest rate contracts	$—	$(21.0)	$—	$(21.0)
Non-qualified supplemental postretirement grantor trust investments (a)	$30.0	$—	$—	$30.0
June 30, 2014 (b):				
Derivative instruments:				
Assets:				
Commodity contracts	$17.9	$15.1	$—	$33.0
Foreign currency contracts	$—	$0.8	$—	$0.8
Liabilities:				
Commodity contracts	$(15.6)	$(15.3)	$—	$(30.9)
Foreign currency contracts	$—	$(5.1)	$—	$(5.1)
Interest rate contracts	$—	$(25.2)	$—	$(25.2)
Cross-currency swaps	$—	$(2.0)	$—	$(2.0)

Non-qualified supplemental postretirement grantor trust investments (a)	$30.4	$—	$—	$30.4

(a) Consists primarily of mutual fund investments held in grantor trusts associated with non-qualified supplemental retirement plans.
(b) Certain immaterial amounts have been revised to correct the classification of derivatives.

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 and foreign 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, 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. At June 30, 2014, the carrying amount and estimated fair value of our long-term debt (including current maturities) were $3,556.2 and $3,805.4, respectively. 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 our short-term investments and trade accounts receivable, could expose us to concentrations of credit risk. We limit our credit risk from short-term investments by investing only in investment-grade commercial paper, money market mutual funds, securities guaranteed by the U.S. Government or its agencies and FDIC insured bank deposits. The credit risk 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.

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, 2015 and 2014, total volumes associated with LPG commodity derivative instruments totaled 405.9 million gallons and 274.3 million gallons, respectively. At June 30, 2015, the maximum period over which we are economically hedging our exposure to LPG commodity price risk is 42 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, 2015 and 2014, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 13.1 million dekatherms and 10.9 million dekatherms, respectively. At June 30, 2015, 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 related to these derivative instruments and the fair values of these contracts are reflected in current and noncurrent derivative instrument assets and liabilities in the accompanying 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, 2015 and 2014, the volumes of Electric Utility's forward electricity purchase contracts were 494.5 million kilowatt hours and 315.8 million kilowatt hours, respectively. At June 30, 2015, the maximum period over which these contracts extend is 11 months.

In order to reduce volatility associated with a substantial portion of its electricity transmission congestion costs, Electric Utility obtains FTRs through an annual allocation process. 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, 2015 and 2014, the total volumes associated with FTRs and NYISO capacity contracts totaled 494.5 million kilowatt hours and 747.4 million kilowatt hours, respectively. At June 30, 2015, 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 contracts, Intercontinental Exchange ("ICE") natural gas basis swap contracts, and electricity futures contracts. Midstream & Marketing also uses NYMEX and over-the-counter electricity futures contracts to 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, 2015 and 2014, total volumes associated with Midstream & Marketing's natural gas futures, forward and pipeline contracts totaled 57.2 million dekatherms and 67.7 million dekatherms, respectively. At June 30, 2015, the

maximum period over which we are hedging our exposure to the variability in cash flows associated with natural gas commodity price risk is 45 months. At June 30, 2015 and 2014, total volumes associated with Midstream & Marketing's electricity call contracts and electricity put contracts totaled 429.5 million kilowatt hours and 210.5 million kilowatt hours, and 492.5 million kilowatt hours and 193.2 million kilowatt hours, respectively. At June 30, 2015, 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 30 months for electricity call contracts and 15 months for electricity put 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, 2014, the volumes associated with Midstream & Marketing's natural gas storage and propane storage NYMEX contracts totaled 0.5 million dekatherms and 2.9 million gallons, respectively.

At June 30, 2015, the amount of net gains associated with commodity derivative instruments previously designated and qualified as cash flow hedges expected to be reclassified into earnings during the next twelve months is not material.

Interest Rate Risk

Antargaz' and Flaga's long-term debt agreements have interest rates that are generally indexed to short-term market interest rates. Antargaz and Flaga have each entered into pay-fixed, receive-variable interest rate swap agreements to hedge the underlying euribor rate of interest on their variable-rate term loans through the respective scheduled maturity dates. As of June 30, 2015 and 2014, the total notional amounts of variable-rate debt subject to interest rate swap agreements (excluding Flaga's cross-currency swap as described below) were €659.1 and €401.1, 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"). At June 30, 2015 and 2014, we had no unsettled IRPAs.

We account for interest rate swaps and IRPAs as cash flow hedges. At June 30, 2015, the amount of net losses associated with interest rate hedges (excluding pay-fixed, receive-variable interest rate swaps) expected to be reclassified into earnings during the next twelve months is $2.6.

Foreign Currency Exchange Rate Risk

In order to reduce volatility, Antargaz hedges a portion of its anticipated U.S. dollar-denominated LPG product purchases during the heating-season months of October through March through the use of forward foreign currency exchange contracts. At June 30, 2015 and 2014, we were hedging a total of $227.9 and $219.8 of U.S. dollar-denominated LPG purchases, respectively. At June 30, 2015, 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 33 months. From time to time we also enter into forward foreign currency exchange contracts to reduce the volatility of the U.S. dollar value on a portion of our International Propane euro-denominated net investments. At June 30, 2015 and 2014, 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, 2015, the amount of net gains associated with currency rate risk (other than net investment hedges) expected to be reclassified into earnings during the next twelve months based upon current fair values is $16.1.

Cross-Currency Swaps

During Fiscal 2013, Flaga entered into a cross-currency swap to hedge its exposure to the variability in expected future cash flows associated with foreign currency and interest rate risk resulting from the issuance of $52 of U.S. dollar-denominated variable-rate debt. The cross-currency hedge includes initial and final exchanges of principal from a fixed euro denomination to a fixed U.S. dollar-denominated amount, to be exchanged at a specified rate, which was determined by the market spot rate on the date of issuance. The cross-currency swap also includes an interest rate swap of a fixed foreign-denominated interest rate to a fixed U.S. dollar-denominated interest rate. We have designated this cross-currency swap as a cash flow hedge. At June 30, 2015, the amount of net gains associated with this cross-currency swap expected to be reclassified into earnings over 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 form of letters of credit, parental guarantees or cash. Additionally, our natural gas and electricity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2015 and 2014, restricted cash in brokerage accounts totaled $45.2 and $5.9, 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, 2015. 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, 2015, if the credit-risk-related contingent features were triggered, the amount of collateral required to be posted would not be material.

Fair Value of Derivative Instruments

The following table presents the Company's derivative assets and liabilities on a gross basis as of June 30, 2015 and 2014:

	June 30, 2015	June 30, 2014 (a)
Derivative assets:		
Derivatives designated as hedging instruments:		
Commodity contracts	$—	$8.1
Foreign currency contracts	29.1	0.8
Cross-currency contracts	8.2	—
Interest rate contracts	1.0	—
	38.3	8.9
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	1.9	2.4
Derivatives not designated as hedging instruments:		
Commodity contracts	19.9	22.5
Total derivative assets	$60.1	$33.8
Derivative liabilities:		
Derivatives designated as hedging instruments:		
Commodity contracts	$—	$(4.2)
Foreign currency contracts	(0.1)	(5.1)
Cross-currency contracts	—	(2.0)
Interest rate contracts	(2.0)	(25.2)
	(2.1)	(36.5)
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	(4.8)	(0.8)
Derivatives not designated as hedging instruments:		
Commodity contracts	(147.8)	(25.9)
Total derivative liabilities	$(154.7)	$(63.2)

(a) Certain immaterial amounts have been revised to correct the classification of derivatives.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities are presented net by counterparty on our Condensed Consolidated Balance Sheets if the right of offset exists. Our derivative 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 our Condensed Consolidated Balance Sheets with our derivative counterparties are not included in the table below but could reduce our net exposure to such counterparties because such balances are subject to master netting or similar arrangements.

The following table presents the Company's derivative assets and liabilities, as well as the effects of offsetting, as of June 30, 2015 and 2014:

	Gross Amounts Recognized	Gross Amounts Offset in Balance Sheet	Net Amounts Recognized	Cash Collateral (Received) Pledged	Net Amounts Recognized in Balance Sheet
June 30, 2015					
Derivative assets	$60.1	$(17.2)	$42.9	$—	$42.9
Derivative liabilities	$(154.7)	$17.2	$(137.5)	$2.2	$(135.3)
June 30, 2014					
Derivative assets	$33.8	$(20.1)	$13.7	$—	$13.7
Derivative liabilities	$(63.2)	$20.1	$(43.1)	$—	$(43.1)

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Effect of Derivative Instruments

The following tables provide information on the effects of derivative instruments in the Condensed Consolidated Statements of Income and changes in AOCI and noncontrolling interests for the three and nine months ended June 30, 2015 and 2014:

Three Months Ended June 30,	Gain (Loss) Recognized in AOCI and Noncontrolling Interests 2015	2014	Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income 2015	2014	Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
Cash Flow Hedges:					
Commodity contracts	$—	$(1.7)	$0.1	$4.3	Cost of sales
Foreign currency contracts	(6.4)	1.1	0.4	(0.2)	Cost of sales
Cross-currency contracts	(1.5)	—	8.6	(0.1)	Interest expense/other operating income, net
Interest rate contracts	0.6	(0.6)	(11.5)	(3.9)	Interest expense
Total	$(7.3)	$(1.2)	$(2.4)	$0.1	

Three Months Ended June 30,	Gain (Loss) Recognized in Income 2015	2014	Location of Gain (Loss) Recognized in Income
Derivatives Not Designated as Hedging Instruments:			
Commodity contracts	$(23.5)	$(4.9)	Cost of sales
Commodity contracts	0.3	—	Revenues
Commodity contracts	0.1	—	Operating expenses / other operating income, net
Total	$(23.1)	$(4.9)	

Nine Months Ended June 30,	Gain (Loss) Recognized in AOCI and Noncontrolling Interests 2015	2014	Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income 2015	2014	Location of Gain (Loss) Reclassified from AOCI and Noncontrolling Interests into Income
Cash Flow Hedges:					
Commodity contracts	$—	$59.5	$(2.2)	$66.5	Cost of sales
Foreign currency contracts	26.0	(1.6)	9.6	(3.7)	Cost of sales
Cross-currency contracts	6.0	(1.1)	8.5	(0.2)	Interest expense/other operating income, net
Interest rate contracts	3.0	(4.1)	(18.9)	(12.0)	Interest expense
Total	$35.0	$52.7	$(3.0)	$50.6	

Nine Months Ended June 30,	Gain (Loss) Recognized in Income 2015	2014	Location of Gain (Loss) Recognized in Income

Derivatives Not Designated as Hedging Instruments:			
Commodity contracts	$(328.3)	$(14.3)	Cost of sales
Commodity contracts	(0.5)	—	Revenues
Commodity contracts	(0.4)	0.1	Operating expenses/other operating income, net
Total	$(329.2)	$(14.2)	

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 for the three and nine months ended June 30, 2015 and 2014.

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 (see Note 8).

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.

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Note 13 — Accumulated Other Comprehensive Income

The tables below present changes in AOCI during the three and nine months ended June 30, 2015 and 2014:

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 income (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 expense	(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)

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

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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 expense	(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)

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

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

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

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Note 14 — Segment Information

Our operations comprise six reportable segments generally based upon products sold, geographic location and regulatory environment. Our reportable segments comprise: (1) AmeriGas Propane; (2) an international LPG segment comprising Antargaz; (3) an international LPG segment principally comprising Flaga and AvantiGas; (4) Gas Utility; (5) Energy Services; and (6) Electric Generation. We refer to both international segments together as "UGI International" and Energy Services and Electric Generation together as "Midstream & Marketing." Finagaz is included in our Antargaz reportable segment in the table below from the date of its acquisition on May 29, 2015.

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 2014 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 net gains and losses on commodity derivative instruments not associated with current-period transactions ("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 chief operating decision maker does not consider such items when evaluating the financial performance of our reportable segments.

					Midstream & Marketing		UGI International		
	Total	Eliminations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Three Months Ended June 30, 2015									
Revenues	$1,148.1	$(27.0) (c)	$478.0	$119.4	$169.7	$16.2	$196.1	$150.7	$45.0
Cost of sales	$586.4	$(26.4) (c)	$211.4	$41.3	$135.9	$7.7	$107.9	$101.8	$6.8
Segment profit:									
Operating income (loss)	$56.1	$—	$0.8	$15.1	$17.3	$1.3	$(9.1)	$8.8	$21.9
Loss from equity investees	—	—	—	—	—	—	—	—	—
Interest expense	(67.5)	—	(40.3)	(9.5)	(0.5)	—	(15.7) (d)	(0.9)	(0.6)
(Loss) income before income taxes	$(11.4)	$—	$(39.5)	$5.6	$16.8	$1.3	$(24.8)	$7.9	$21.3
Partnership Adjusted EBITDA (a)			$48.9						
Noncontrolling interests' net income	$(25.5)	$—	$(36.1)	$—	$—	$—	$(0.2)	$—	$10.8

(loss)									
Depreciation and amortization	$92.5	$0.1	$48.0	$14.8	$3.7	$ 3.2	$15.2	$5.9	$ 1.6
Capital expenditures	$113.2	$—	$20.7	$41.3	$27.5	$ 1.1	$17.2	$3.3	$ 2.1

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					Midstream & Marketing		UGI International		
	Total	Elim-inations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Three Months Ended June 30, 2014									
Revenues	$1,486.7	$(50.8)(c)	$613.2	$128.3	$248.3	$ 20.5	$249.2	$232.3	$45.7
Cost of sales	$926.5	$(49.6)(c)	$340.8	$49.2	$209.2	$ 10.5	$164.1	$180.7	$21.6
Segment profit:									
Operating income (loss)	$62.7	$(0.1)	$7.2	$17.1	$23.5	$ 2.6	$(1.4)	$8.2	$5.6
Loss from equity investees	(0.1)	—	—	—	—	—	(0.1)	—	—
Interest expense	(60.1)	—	(41.4)	(9.8)	(0.5)	—	(6.3)	(1.4)	(0.7)
Income (loss) before income taxes	$2.5	$(0.1)	$(34.2)	$7.3	$23.0	$ 2.6	$(7.8)	$6.8	$4.9
Partnership Adjusted EBITDA (a)			$55.1						
Noncontrolling interests' net loss	$(33.3)	$—	$(31.0)	$—	$—	$ —	$(0.3)	$—	$(2.0)
Depreciation and amortization	$90.0	$—	$47.8	$13.7	$3.3	$ 2.7	$14.6	$6.2	$1.7
Capital expenditures	$102.4	$1.2	$29.3	$35.9	$11.2	$ 1.9	$15.6	$4.8	$2.5

					Midstream & Marketing		UGI International		
	Total	Elim-inations	AmeriGas Propane	Gas Utility	Energy Services	Electric Generation	Antargaz	Flaga & Other	Corporate & Other (b)
Nine Months Ended June 30, 2015									