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 March 31, 2017

OR

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

For the transition period from ________ to ________

Commission file number 1-11071

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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

At April 30, 2017, there were 173,122,616 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)

	March 31, 2017	September 30, 2016	March 31, 2016
ASSETS			
Current assets:			
Cash and cash equivalents	$ 637.8	$ 502.8	$ 466.2
Restricted cash	0.3	15.6	40.0
Accounts receivable (less allowances for doubtful accounts of $34.7, $27.3 and $34.1, respectively)	920.4	551.6	858.4
Accrued utility revenues	36.7	12.8	24.1
Inventories	203.0	210.3	176.5
Utility regulatory assets	2.3	3.2	3.2
Derivative instruments	49.2	30.9	21.0
Prepaid expenses and other current assets	90.6	96.6	117.6
Total current assets	1,940.3	1,423.8	1,707.0
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $3,221.9, $3,107.3 and $2,987.1, respectively)	5,298.6	5,238.0	5,083.1
Goodwill	2,948.4	2,989.0	2,998.6
Intangible assets, net	551.0	580.3	598.2
Utility regulatory assets	392.4	391.9	345.0
Derivative instruments	11.4	6.5	1.2
Other assets	243.4	217.7	192.7
Total assets	$ 11,385.5	$ 10,847.2	$ 10,925.8
LIABILITIES AND EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 170.5	$ 29.5	$ 8.5
Short-term borrowings	50.1	291.7	227.1
Accounts payable	467.6	391.2	379.8
Derivative instruments	5.0	48.5	70.2
Other current liabilities	674.6	681.1	781.1
Total current liabilities	1,367.8	1,442.0	1,466.7
Long-term debt	4,025.5	3,766.0	3,600.9
Deferred income taxes	1,267.6	1,216.2	1,186.7
Deferred investment tax credits	3.1	3.3	3.4
Derivative instruments	5.9	21.9	20.4
Other noncurrent liabilities	778.2	796.0	722.7
Total liabilities	7,448.1	7,245.4	7,000.8
Commitments and contingencies (Note 9)			
Equity:			
UGI Corporation stockholders' equity:			
UGI Common Stock, without par value (authorized — 450,000,000 shares; issued — 173,949,791, 173,894,141 and 173,842,891 shares, respectively)	1,190.4	1,201.6	1,205.8
Retained earnings	2,214.2	1,840.9	1,906.2
Accumulated other comprehensive loss	(204.5)	(154.7)	(129.9)
Treasury stock, at cost	(34.9)	(36.9)	(41.9)
Total UGI Corporation stockholders' equity	3,165.2	2,850.9	2,940.2
Noncontrolling interests, principally in AmeriGas Partners	772.2	750.9	984.8
Total equity	3,937.4	3,601.8	3,925.0
Total liabilities and equity	$ 11,385.5	$ 10,847.2	$ 10,925.8

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 March 31,		Six Months Ended March 31,	
	2017	2016	2017	2016
Revenues	$ 2,173.8	$ 1,972.1	$ 3,853.3	$ 3,578.7
Costs and expenses:				
Cost of sales (excluding depreciation shown below)	1,071.2	776.9	1,718.6	1,510.9
Operating and administrative expenses	486.2	481.0	951.0	945.1
Utility taxes other than income taxes	4.9	4.4	8.6	8.2
Depreciation	84.8	83.4	168.5	169.1
Amortization	14.5	17.3	28.9	32.2
Other operating income, net	(1.0)	(6.3)	(1.7)	(7.7)
	1,660.6	1,356.7	2,873.9	2,657.8
Operating income	513.2	615.4	979.4	920.9
Income (loss) from equity investees	2.3	—	2.1	(0.1)
Loss on extinguishments of debt	(22.1)	—	(55.3)	—
(Losses) gains on foreign currency contracts, net	(1.2)	—	0.1	—
Interest expense	(55.8)	(57.3)	(111.2)	(115.2)
Income before income taxes	436.4	558.1	815.1	805.6
Income tax expense	(124.6)	(150.1)	(212.4)	(229.7)
Net income including noncontrolling interests	311.8	408.0	602.7	575.9
Deduct net income attributable to noncontrolling interests, principally in AmeriGas Partners	(91.9)	(174.8)	(152.1)	(228.1)
Net income attributable to UGI Corporation	$ 219.9	$ 233.2	$ 450.6	$ 347.8
Earnings per common share attributable to UGI Corporation stockholders:				
Basic	$ 1.27	$ 1.35	$ 2.60	$ 2.01
Diluted	$ 1.24	$ 1.33	$ 2.55	$ 1.99
Weighted average common shares outstanding (thousands):				
Basic	173,624	172,619	173,567	172,733
Diluted	177,136	174,845	176,976	174,953
Dividends declared per common share	$ 0.2375	$ 0.2275	$ 0.4750	$ 0.4550

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 March 31,		Six Months Ended March 31,	
	2017	2016	2017	2016
Net income including noncontrolling interests	$ 311.8	$ 408.0	$ 602.7	$ 575.9
Other comprehensive income (loss):				
Net (losses) gains on derivative instruments (net of tax of $0.3, $18.5, $(5.7) and $14.3, respectively)	(0.5)	(29.7)	11.8	(22.9)
Reclassifications of net gains on derivative instruments (net of tax of $2.5, $2.7, $4.6 and $5.9, respectively)	(5.4)	(4.3)	(9.9)	(9.6)
Foreign currency adjustments	17.8	46.7	(53.1)	16.5
Benefit plans (net of tax of $(0.3), $(0.1), $(0.9) and $(0.4), respectively)	0.4	0.3	1.4	0.7
Other comprehensive income (loss)	12.3	13.0	(49.8)	(15.3)
Comprehensive income including noncontrolling interests	324.1	421.0	552.9	560.6
Deduct comprehensive income attributable to noncontrolling interests, principally in AmeriGas Partners	(91.9)	(174.8)	(152.1)	(228.1)
Comprehensive income attributable to UGI Corporation	$ 232.2	$ 246.2	$ 400.8	$ 332.5

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Six Months Ended March 31, 2017	Six Months Ended March 31, 2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income including noncontrolling interests	$ 602.7	$ 575.9
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities:		
Depreciation and amortization	197.4	201.3
Deferred income taxes	49.4	49.5
Provision for uncollectible accounts	15.3	14.8
Change in unrealized gains on derivative instruments	(81.6)	(65.1)
Loss on extinguishments of debt	55.3	—
Other, net	24.0	0.9
Net change in:		
Accounts receivable and accrued utility revenues	(424.3)	(268.8)
Inventories	3.9	63.6
Utility deferred fuel and power costs, net of changes in unsettled derivatives	(7.6)	(7.8)
Accounts payable	129.4	(5.9)
Other current assets	(1.3)	(12.6)
Other current liabilities	22.4	72.5
Net cash provided by operating activities	585.0	618.3
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(341.8)	(254.6)
Acquisitions of businesses, net of cash acquired	(7.3)	(49.4)
Decrease in restricted cash	15.3	29.3
Other, net	(4.3)	6.5
Net cash used by investing activities	(338.1)	(268.2)
CASH FLOWS FROM FINANCING ACTIVITIES		
Dividends on UGI Common Stock	(82.3)	(78.5)
Distributions on AmeriGas Partners publicly held Common Units	(130.1)	(127.2)
Issuances of debt, net of issuance costs	1,307.1	—
Repayments of debt, including redemption premiums	(928.6)	(78.4)
(Decrease) increase in short-term borrowings	(216.1)	52.6
Receivables Facility net repayments	(25.5)	(15.5)
Issuances of UGI Common Stock	5.9	5.2
Repurchases of UGI Common Stock	(25.5)	(24.7)
Other	(0.8)	6.9
Net cash used by financing activities	(95.9)	(259.6)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(16.0)	6.0
Cash and cash equivalents increase	$ 135.0	$ 96.5
CASH AND CASH EQUIVALENTS		
End of period	$ 637.8	$ 466.2
Beginning of period	502.8	369.7
Increase	$ 135.0	$ 96.5

See accompanying notes to condensed consolidated financial statements.

UGI CORPORATION AND SUBSIDIARIES

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

	Six Months Ended March 31, 2017	Six Months Ended March 31, 2016
Common stock, without par value		
Balance, beginning of period	$ 1,201.6	$ 1,214.6
Common Stock issued in connection with employee and director plans (including losses on treasury stock transactions), net of tax withheld	(20.7)	(22.4)
Excess tax benefits realized on equity-based compensation	—	6.9
Equity-based compensation expense	8.1	6.7
Gain on sale of treasury stock	1.4	—
Balance, end of period	$ 1,190.4	$ 1,205.8
Retained earnings		
Balance, beginning of period	$ 1,840.9	$ 1,636.9
Cumulative effect of change in accounting for employee share-based payments	5.0	—
Net income attributable to UGI Corporation	450.6	347.8
Cash dividends on Common Stock	(82.3)	(78.5)
Balance, end of period	$ 2,214.2	$ 1,906.2
Accumulated other comprehensive income (loss)		
Balance, beginning of period	$ (154.7)	$ (114.6)
Net gains (losses) on derivative instruments	11.8	(22.9)
Reclassification of net gains on derivative instruments	(9.9)	(9.6)
Benefit plans	1.4	0.7
Foreign currency	(53.1)	16.5
Balance, end of period	$ (204.5)	$ (129.9)
Treasury stock		
Balance, beginning of period	$ (36.9)	$ (44.9)
Common stock issued in connection with employee and director plans, net of tax withheld	33.7	42.1
Repurchases of Common Stock	(25.5)	(24.7)
Reacquired common stock — employee and director plans	(6.4)	(14.4)
Sale of treasury stock	0.2	—
Balance, end of period	$ (34.9)	$ (41.9)
Total UGI Corporation stockholders' equity	$ 3,165.2	$ 2,940.2
Noncontrolling interests		
Balance, beginning of period	$ 750.9	$ 880.4
Net income attributable to noncontrolling interests, principally in AmeriGas Partners	152.1	228.1
Dividends and distributions	(130.1)	(127.2)
Other	(0.7)	3.5
Balance, end of period	$ 772.2	$ 984.8
Total equity	$ 3,937.4	$ 3,925.0

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"). 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 March 31, 2017, 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 14 of our Annual Report on Form 10-K for the fiscal year ended September 30, 2016 (the "Company's 2016 Annual Report"). Incentive distributions received by the General Partner during the six months ended March 31, 2017 and 2016 were $20.9 and $17.3, respectively.

Our wholly owned subsidiary, UGI Enterprises, Inc. ("Enterprises"), through subsidiaries, conducts an LPG distribution business principally in France, the United Kingdom, and central, northern and eastern Europe. These businesses are conducted principally through our subsidiaries, UGI France SAS, Flaga GmbH and AvantiGas Limited. We also conduct a natural gas marketing business principally in France. In March 2016, we sold our LPG business located in the Nantong region of China. We refer to the foreign operations collectively as "UGI International."

UGI Energy Services, LLC ("Energy Services, LLC"), a wholly owned subsidiary of Enterprises, conducts directly and through subsidiaries an energy marketing, midstream transmission, liquefied natural gas ("LNG"), storage, natural gas gathering, natural gas production, electricity generation and energy services business primarily in the Mid-Atlantic and Northeast U.S. Energy Services, LLC's wholly owned subsidiary, UGI Development Company ("UGID"), owns all or a portion of electricity generation facilities principally located in Pennsylvania. A first-tier subsidiary of Enterprises also conducts heating, ventilation, air-conditioning, refrigeration and electrical contracting businesses in the Mid-Atlantic region ("HVAC"). Energy Services, LLC and its subsidiaries' storage, LNG and portions of its midstream transmission operations are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). We refer to the businesses of Energy Services, LLC and its subsidiaries and HVAC as "Midstream & Marketing."

UGI Utilities, Inc. ("UGI Utilities") conducts a natural gas distribution utility business ("Gas Utility") directly and through its wholly owned 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. UGI Utilities is used herein as an abbreviated reference to UGI Utilities, Inc. or, collectively, UGI Utilities, Inc. and its subsidiaries.

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, 2016, 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 2016 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 March 31,		Six Months Ended March 31,	
	2017	2016	2017	2016
Denominator (thousands of shares):				
Weighted-average common shares outstanding — basic	173,624	172,619	173,567	172,733
Incremental shares issuable for stock options and awards (a)	3,512	2,226	3,409	2,220
Weighted-average common shares outstanding — diluted	177,136	174,845	176,976	174,953

(a) See "*Adoption of New Accounting Standard — Employee Share-based Payments*" below for the impact on the calculation of diluted shares for the three and six months ended March 31, 2017 resulting from the adoption of new accounting guidance regarding share-based payments.

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 UGI Utilities (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.

Beginning October 1, 2016, in order to reduce the volatility in net income associated with our foreign operations, principally as a result of changes in the U.S. dollar exchange rate between the euro and British pound sterling, we enter into forward foreign currency exchange contracts. Because these contracts do not qualify for hedge accounting treatment, realized and unrealized gains and losses on these contracts are recorded in "(Losses) gains on foreign currency contracts, net" 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

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

hedges, if any, 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, if any, are included in cash flow from operating activities while cash flows from the currency portion of such hedges, if any, 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.

Impairment of Cost Basis Investments. We reduce the carrying values of our cost basis investments when we determine that a decline in fair value is other than temporary. In March 2017, we recorded a pre-tax loss of $7.0 associated with an other-than-temporary impairment of our investment in a private equity partnership that invests in renewable energy companies. This loss is reflected in “Other operating income, net” on the Condensed Consolidated Statements of Income. At March 31, 2017, the carrying amount of this investment was $11.0.

Deferred Debt Issuance Costs. During the fourth quarter of Fiscal 2016, we adopted new accounting guidance regarding the classification of deferred debt issuance costs. Deferred debt issuance costs associated with long-term debt are reflected as a direct deduction from the carrying amount of such debt. Deferred debt issuance costs associated with line of credit facilities continue to be classified as “Other assets” on our Condensed Consolidated Balance Sheets. As a result of the retrospective application of the new accounting guidance, the Company has reflected $29.6 of such costs as a reduction to long-term debt, including current maturities, on the accompanying March 31, 2016, Condensed Consolidated Balance Sheet. Previously, these costs were presented within “Other assets.”

Income Taxes. UGI’s consolidated effective income tax rate, defined as total income taxes 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.

In December 2016, the French Parliament approved the Finance Bill for 2017 and amended the Finance Bill for 2016 (collectively, the “Finance Bills”). The Finance Bills, among other things, will reduce UGI France’s corporate income tax rate from the current 34.43% to 28.92%, effective for fiscal years starting after January 1, 2020 (Fiscal 2021). As a result of the future income tax rate reduction, in December 2016, the Company reduced its net deferred income tax liabilities and recognized an estimated deferred tax benefit of $27.4 (equal to $0.15 per basic and diluted share).

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.

Adoption of New Accounting Standard — Employee Share-based Payments. Effective October 1, 2016, the Company adopted new accounting guidance issued to simplify several aspects of 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. Among other things, excess tax benefits and tax deficiencies associated with employee share-based awards that vest or are exercised are recognized as income tax benefit or expense and treated as discrete items in the reporting period in which they occur. In addition, assumed proceeds under the treasury stock method used for computing diluted shares outstanding do not include windfall tax benefits in the diluted shares calculation.

In accordance with the required prospective method of transition relating to excess tax benefits, the Company recognized income tax benefits of $4.8 and $7.0 related to excess tax benefits for share-based awards that were exercised or vested during the three and six months ended March 31, 2017, respectively. These amounts are reflected in “Income tax expense” on the Condensed Consolidated Statements of Income. In addition, as of October 1, 2016, the Company recorded a $5.0 cumulative adjustment to increase retained earnings and decrease deferred income tax liabilities for excess tax benefits related to prior period unrecognized excess state tax benefits. The Company elected to use the prospective method of transition for classifying excess tax benefits as a cash flow from operating activity on the Condensed Consolidated Statements of Cash Flows and prior periods were not adjusted. The Company has historically presented employee taxes paid for net settled awards as a financing activity on the Condensed

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

Consolidated Statements of Cash Flows and therefore there is no transition impact from this requirement. In addition, as provided by the new guidance, the Company has elected to account for forfeitures of share-based payments when they occur.

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

Note 3 — Accounting Changes

Adoption of New Accounting Standards

Employee Share-based Payments. Effective October 1, 2016, the Company adopted new accounting guidance regarding share-based payments. See Note 2 for a detailed description of the impact of the new guidance.

Equity Method Accounting. Effective October 1, 2016, the Company adopted new accounting guidance regarding the accounting for an investment that qualifies for use of the equity method as a result of an increase in an investor's level of ownership or influence. The guidance requires that the equity method investor add the cost of acquiring an additional interest to the current basis of the investor's previously held interest and adopt the equity method of accounting as of the date such investment qualifies for equity method accounting. The new guidance eliminates the previous requirement in such circumstances to apply the effects of the equity method of accounting retrospectively. The guidance is required to be applied prospectively. The adoption of the new guidance did not impact our consolidated financial statements.

Accounting Standards Not Yet Adopted

Pension and Other Postretirement Benefit Costs. In March 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." This ASU requires entities to disaggregate the service cost component from the other components of net periodic benefit costs and present it with compensation costs for related employees in the income statement. The other components are required to be presented elsewhere in the income statement and outside of operating income. The amendments in this ASU permit only the service cost component to be eligible for capitalization when applicable. The amendments in this ASU are effective for interim and annual periods beginning after December 15, 2017 (Fiscal 2019). Early adoption is permitted. The amendments in the ASU should generally be adopted on a retrospective basis. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance and determining the period in which the new guidance will be adopted.

Goodwill Impairment. In January 2017, the FASB issued ASU No. 2017-04, "Simplifying the Test for Goodwill Impairment." Under the new accounting guidance, an entity will no longer determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Instead, an entity will perform its goodwill impairment tests by comparing the fair value of a reporting unit with its carrying amount. An entity will recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value but not to exceed the total amount of the goodwill of the reporting unit. In addition, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment, if applicable. The provisions of the new accounting guidance are required to be applied prospectively. The new accounting guidance is effective for the Company for goodwill impairment tests performed in fiscal years beginning after December 15, 2019 (Fiscal 2021). Early adoption is permitted for goodwill impairment tests performed after January 1, 2017. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance and determining the period in which the new guidance will be adopted.

Cash Flow Classification. In August 2016, the FASB issued ASU No. 2016-15, "Classification of Certain Cash Receipts and Cash Payments." This ASU provides guidance on the classification of certain cash receipts and payments in the statement of cash flows. The amendments in this ASU are effective for interim and annual periods beginning after December 15, 2017 (Fiscal 2019). Early adoption is permitted. The amendments in the ASU should generally be adopted on a retrospective basis. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance and determining the period in which the new guidance will be adopted.

In November 2016, the FASB issued ASU No. 2016-18, "Statement of Cash Flows: Restricted Cash." This ASU provides guidance on the classification of restricted cash in the statement of cash flows. The amendments in this ASU are effective for interim and annual periods beginning after December 15, 2017 (Fiscal 2019). Early adoption is permitted. The amendments in the ASU should be adopted on a retrospective basis. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance and determining the period in which the new guidance will be adopted.

(Currency in millions, except per share amounts)

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. 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 and determining the period in which the new guidance will be adopted but anticipates an increase in the recognition of right-of-use assets and lease liabilities.

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 Accounting Standards Codification (“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. The Company has not yet selected a transition method and is in the process of assessing the impact on its financial statements from the adoption of the new guidance.

Note 4 — Inventories

Inventories comprise the following:

	March 31, 2017	September 30, 2016	March 31, 2016
Non-utility LPG and natural gas	$ 143.1	$ 129.8	$ 106.7
Gas Utility natural gas	2.4	29.2	3.8
Materials, supplies and other	57.5	51.3	66.0
Total inventories	$ 203.0	$ 210.3	$ 176.5

At March 31, 2017, UGI Utilities was a party to five principal storage contract administrative agreements (“SCAAs”) having terms ranging from one to three years. Pursuant to SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon commencement of the SCAAs, will receive a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the 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 March 31, 2017, UGI Utilities had SCAAs with Energy Services and a non-affiliate. There were no gas storage inventories released under SCAAs with the non-affiliate at March 31, 2017. The carrying value of gas storage inventories released under the SCAAs with the non-affiliate at September 30, 2016 and March 31, 2016, comprising 3.5 billion cubic feet (“bcf”) and 0.2 bcf of natural gas, was $7.6 and $0.5, respectively.

(Currency in millions, except per share amounts)

Note 5 — Goodwill and Intangible Assets

Goodwill and intangible assets comprise the following:

	March 31, 2017	September 30, 2016	March 31, 2016
Goodwill (not subject to amortization)	$ 2,948.4	$ 2,989.0	$ 2,998.6
Intangible assets:			
Customer relationships, noncompete agreements and other	$ 764.3	$ 773.5	$ 778.3
Accumulated amortization	(342.4)	(324.8)	(312.3)
Intangible assets, net (definite-lived)	421.9	448.7	466.0
Trademarks and tradenames (indefinite-lived)	129.1	131.6	132.2
Total intangible assets, net	$ 551.0	$ 580.3	$ 598.2

The changes in goodwill and intangible assets are primarily due to acquisitions and the effects of currency translation. Amortization expense of intangible assets was $12.4 and $15.2 for the three months ended March 31, 2017 and 2016, respectively. Amortization expense of intangible assets was $24.9 and $28.0 for the six months ended March 31, 2017 and 2016, 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 2017 and for the next four fiscal years is as follows: remainder of Fiscal 2017 — $24.2; Fiscal 2018 — $47.1; Fiscal 2019 — $45.3; Fiscal 2020 — $43.9; Fiscal 2021 — $42.0.

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 8 in the Company’s 2016 Annual Report. Other than removal costs, UGI Utilities currently does not recover a rate of return on its regulatory assets. The following regulatory assets and liabilities associated with UGI Utilities are included in our accompanying Condensed Consolidated Balance Sheets:

	March 31, 2017	September 30, 2016	March 31, 2016
Regulatory assets:			
Income taxes recoverable	$ 120.3	$ 115.7	$ 118.2
Underfunded pension and postretirement plans	175.6	183.1	135.8
Environmental costs	62.2	59.4	60.5
Deferred fuel and power costs	1.3	0.1	—
Removal costs, net	28.8	27.9	25.0
Other	6.5	8.9	8.7
Total regulatory assets	$ 394.7	$ 395.1	$ 348.2
Regulatory liabilities (a):			
Postretirement benefits	$ 17.0	$ 17.5	$ 19.3
Deferred fuel and power refunds	13.8	22.3	30.8
State tax benefits — distribution system repairs	16.1	15.1	14.2
Other	3.6	0.7	2.5
Total regulatory liabilities	$ 50.5	$ 55.6	$ 66.8

(a) Regulatory liabilities are recorded in “Other current liabilities” 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 March 31, 2017, September 30, 2016 and March 31, 2016 were $2.0, $4.3 and $(1.9), respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. At March 31, 2017, September 30, 2016 and March 31, 2016, substantially 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 March 31, 2017, September 30, 2016, and March 31, 2016, were not material.

Base Rate Filings. On January 19, 2017, PNG filed a rate request with the PUC to increase PNG's base operating revenues for residential, commercial and industrial customers by $21.7 annually. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. PNG requested that the new gas rates become effective March 20, 2017. The PUC entered an Order dated February 9, 2017, suspending the effective date for the rate increase to allow for investigation and public hearings. Unless a settlement is reached sooner, this review process is expected to last up to nine months from the date of filing; however, the Company cannot predict the timing or the ultimate outcome of the rate case review process.

On October 14, 2016, the PUC approved a previously filed Joint Petition for Approval of Settlement of all issues providing for a $27.0 annual base distribution rate increase for UGI Gas. The increase became effective on October 19, 2016.

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 5% of distribution charges billed to customers.

PNG and CPG received PUC approval on a DSIC tariff, initially set at zero, in 2014. 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 5% to 10% of billed distribution revenues. On April 20, 2017, the PUC voted to approve an increase of the maximum allowable DSIC to 7.5% of billed distribution revenues effective July 1, 2017 for PNG and CPG, pending the issuance of a final order of the PUC.

On November 9, 2016, UGI Gas received PUC approval to establish a DSIC tariff mechanism effective January 1, 2017. Revenue collected pursuant to the mechanism will be subject to refund and recoupment based on the PUC's final resolution of certain matters set aside for hearing before an administrative law judge. UGI Gas will be permitted to recover revenue under the mechanism for the amount of DSIC-eligible plant placed into service in excess of the threshold amount of DSIC-eligible plant agreed upon in the settlement of its recent base rate case. Achievement of that threshold is not likely to occur prior to September 30, 2017.

Note 7 — Energy Services Accounts Receivable Securitization Facility

Energy Services, LLC has an accounts receivable securitization facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in October 2017. The Receivables Facility provides Energy Services with the ability to borrow up to $150 of eligible receivables during the period November to April and up to $75 of eligible receivables during the period May to October. Energy Services, LLC uses the Receivables Facility to fund working capital, margin calls under commodity futures contracts, capital expenditures, dividends and for general corporate purposes.

(Currency in millions, except per share amounts)

Under the Receivables Facility, Energy Services, LLC 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. Amounts sold to the bank are reflected as "Short-term borrowings" on the Condensed Consolidated Balance Sheets. ESFC was created and has been structured to isolate its assets from creditors of Energy Services, LLC 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, LLC continues to service, administer and collect trade receivables on behalf of the bank, as applicable. Losses on sales of receivables to the bank during the three and six months ended March 31, 2017 and 2016, which are included in "Interest expense" on the Condensed Consolidated Statements of Income, were not material.

Information regarding the trade receivables transferred to ESFC and the amounts sold to the bank for the six months ended March 31, 2017 and 2016, as well as the balance of ESFC trade receivables at March 31, 2017, September 30, 2016 and March 31, 2016, is as follows:

	Six Months Ended March 31,	
	2017	2016
Trade receivables transferred to ESFC during the period	$ 633.7	$ 468.0
ESFC trade receivables sold to the bank during the period	$ 151.0	$ 167.5

	March 31, 2017	September 30, 2016	March 31, 2016
ESFC trade receivables - end of period (a)	$ 85.3	$ 35.7	$ 55.3

(a) At March 31, 2017, no ESFC trade receivables were sold to the bank. At September 30, 2016 and March 31, 2016, the amounts of ESFC trade receivables sold to the bank were $25.5 and $4.0, respectively, and are reflected as "Short-term borrowings" on the Condensed Consolidated Balance Sheets.

Note 8 — Debt

UGI Utilities

Pursuant to a Note Purchase Agreement, in October 2016, UGI Utilities issued $100 aggregate principal amount of 4.12% Senior Notes due October 2046 (the "UGI Utilities' 4.12% Senior Notes"). The net proceeds of the issuance of the UGI Utilities' 4.12% Senior Notes were used (1) to provide additional financing for UGI Utilities' infrastructure replacement and betterment capital program and information technology initiatives and (2) for general corporate purposes. The UGI Utilities' 4.12% Senior Notes are unsecured and rank equally with UGI Utilities' existing outstanding senior debt.

AmeriGas Propane

In December 2016, AmeriGas Partners issued $700 principal amount of 5.50% Senior Notes due May 2025 (the "AmeriGas Partners' 5.50% Senior Notes"). The AmeriGas Partners' 5.50% Senior Notes rank equally with AmeriGas Partners' existing outstanding senior notes. The net proceeds from the issuance of the AmeriGas Partners' 5.50% Senior Notes were used in December 2016 for (1) the early repayment, pursuant to a tender offer, of a portion of AmeriGas Partners' 7.00% Senior Notes having an aggregate principal balance of $500.0 plus accrued and unpaid interest and early redemption premiums; (2) the reduction of short-term borrowings; and (3) general corporate purposes.

In February 2017, AmeriGas Partners issued $525 principal amount of 5.75% Senior Notes due May 2027 (the "AmeriGas Partners' 5.75% Senior Notes"). The AmeriGas Partners' 5.75% Senior Notes rank equally with AmeriGas Partners' existing outstanding senior notes. The net proceeds from the issuance of the AmeriGas Partners' 5.75% Senior Notes were used in February 2017 for (1) the early repayment, pursuant to a tender offer, of a portion of AmeriGas Partners' 7.00% Senior Notes having an aggregate principal balance of $378.3 plus accrued and unpaid interest and early redemption premiums; (2) the repayment of short-term borrowings; and (3) general corporate purposes.

In connection with these early repayments of AmeriGas' 7.00% Senior Notes, during the three and six months ended March 31, 2017, the Partnership recognized pre-tax losses of $22.1 and $55.3, comprising $18.9 and $47.7 of early redemption premiums and the write-off of $3.2 and $7.6 of unamortized debt issuance costs, respectively. The pre-tax losses are reflected in "Loss on extinguishments of debt" on the Condensed Consolidated Statements of Income.

In March 2017, AmeriGas Partners issued a notice of early redemption for the remaining AmeriGas Partners' 7.00% Senior Notes not previously tendered, having an aggregate principal balance of $102.5, plus early redemption premiums and accrued and unpaid interest. These 7.00% Senior Notes, which have a redemption date of May 20, 2017, are included in "Current maturities of long-term debt" on the March 31, 2017, Condensed Consolidated Balance Sheet. The Partnership expects to recognize a pre-tax loss on extinguishment of debt of approximately $5.0 during the third quarter of Fiscal 2017 associated with this redemption.

Note 9 — Commitments and Contingencies

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 also has two acquired subsidiaries (CPG and PNG) with similar histories of owning, and in some cases operating, MGPs in Pennsylvania.

Each of UGI Utilities and its subsidiaries, CPG and PNG, has entered into an agreement with the Pennsylvania Department of Environmental Protection ("DEP") to address the remediation of former MGPs in Pennsylvania (each, a "COA"). The COAs require UGI Gas, CPG and PNG 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 previously operated ("MGP Properties") and, in the case of CPG, to plug a minimum number of non-producing natural gas wells per year. Under these agreements, in any calendar year, required environmental expenditures relating to the MGP Properties and, with respect to CPG, the natural gas wells, are capped at $2.5, $1.8, and $1.1, for UGI Gas, CPG and PNG, respectively. The COAs for UGI Gas, CPG and PNG are scheduled to terminate at the end of 2031, 2018, and 2019, respectively, but each COA may be terminated by either party at the end of any two-year period beginning with the original effective date of the COA. At March 31, 2017, September 30, 2016 and March 31, 2016, our estimated accrued liabilities for environmental investigation and remediation costs related to the COAs for UGI Gas, CPG and PNG totaled $55.7, $55.1 and $55.5, respectively. UGI Gas, CPG, and PNG have 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 UGI Gas, CPG and PNG receive ratemaking recovery of actual environmental investigation and remediation costs associated with the sites covered by the COAs. This ratemaking recognition reconciles the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites.

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 March 31, 2017, September 30, 2016 and March 31, 2016, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Utilities' MGP sites outside of Pennsylvania was material.

Other Matters

Class Action Judgment. In connection with the Partnership's 2012 acquisition of the subsidiaries of Energy Transfer Partners, L.P. ("ETP") that operated ETP's propane distribution business ("Heritage Propane"), the Partnership became party to a class action lawsuit that was filed against Heritage Operating, L.P. in 2005 by Alfred L. Williams, II, on behalf of himself and all others similarly situated. The class action lawsuit alleged, among other things, wrongful collection of tank rental payments from legacy customers of People's Gas, which was acquired by Heritage Propane in 2000. In 2010, the Florida District Court certified the class and in January 2015, the Florida District Court awarded the class approximately $18.0. In April 2016, the Partnership appealed the verdict to the Florida Second District Court of Appeals (the "Second DCA") and, in September 2016, the Second DCA affirmed the verdict without opinion. Prior to the Second DCA's action in the case, we believed that the likelihood of the Second DCA affirming the Florida District Court's decision was remote. As a result of the Second DCA's actions, in September 2016, the Partnership recorded a $15.0 adjustment to its litigation accrual to reflect the full amount of the judgment plus associated interest. In October 2016, the Partnership filed a Motion for Written Opinion and for Rehearing En Banc with the Second DCA. Following denial of such motion, the Partnership satisfied such judgment.

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 ("District Court"). In July 2015, the District 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 ("Eighth Circuit") and, in August 2016, the Eighth Circuit affirmed the District Court's dismissal of the direct customer's claims against the Partnership/UGI Corporation. The direct customers filed a petition requesting an en banc review of the Eighth Circuit, which was granted. The rehearing occurred in April 2017. The indirect customers filed an amended complaint with the District Court claiming injunctive relief and state law claims under Wisconsin, Maine and Vermont law. In September 2016, the District Court dismissed the amended complaint in its entirety. The indirect customers appealed this decision to the Eighth Circuit; this appeal has been stayed pending the en banc review of the direct purchasers' claims. On July 21, 2016, several new indirect customer plaintiffs filed an antitrust class action lawsuit against the Partnership in the Western District of Missouri. This new indirect customer class action lawsuit was dismissed in September 2016 and certain indirect customer plaintiffs appealed this decision, consolidating their appeal with the indirect customer appeal still pending in the Eighth Circuit. 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 statements.

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 postretirement life insurance benefits to nearly all U.S. active and retired employees. In addition, employees of UGI France SAS and its subsidiaries are covered by certain defined benefit pension and postretirement plans.

(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 March 31,	2017	2016	2017	2016
Service cost	$ 3.0	$ 2.5	$ 0.3	$ 0.2
Interest cost	6.1	6.6	0.2	0.3
Expected return on assets	(8.3)	(8.0)	(0.1)	(0.1)
Amortization of:				
Prior service cost (benefit)	—	0.1	(0.2)	(0.2)
Actuarial loss	4.2	2.7	—	—
Net benefit cost	5.0	3.9	0.2	0.2
Change in associated regulatory liabilities	—	—	(0.1)	0.8
Net benefit cost after change in regulatory liabilities	$ 5.0	$ 3.9	$ 0.1	$ 1.0

	Pension Benefits		Other Postretirement Benefits	
Six Months Ended March 31,	2017	2016	2017	2016
Service cost	$ 6.0	$ 5.0	$ 0.5	$ 0.4
Interest cost	12.3	13.2	0.4	0.5
Expected return on assets	(16.6)	(16.0)	(0.3)	(0.3)
Amortization of:				
Prior service cost (benefit)	0.1	0.2	(0.3)	(0.3)
Actuarial loss	8.3	5.4	0.1	—
Net benefit cost	10.1	7.8	0.4	0.3
Change in associated regulatory liabilities	—	—	(0.2)	1.7
Net benefit cost after change in regulatory liabilities	$ 10.1	$ 7.8	$ 0.2	$ 2.0

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 six months ended March 31, 2017 and 2016, the Company made cash contributions to the U.S. Pension Plan of $5.7 and $4.9, respectively. The Company expects to make additional discretionary cash contributions of approximately $5.5 to the U.S. Pension Plan during the remainder of Fiscal 2017.

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 six months ended March 31, 2017 and 2016.

We also sponsor unfunded and non-qualified supplemental executive defined benefit retirement plans. Net periodic costs associated with these plans for the three and six months ended March 31, 2017 and 2016, were not material.

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 March 31, 2017, September 30, 2016 and March 31, 2016:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
March 31, 2017:				
Derivative instruments:				
Assets:				
Commodity contracts	$ 56.0	$ 18.0	$ —	$ 74.0
Foreign currency contracts	$ —	$ 15.6	$ —	$ 15.6
Cross-currency contracts	$ —	$ 3.0	$ —	$ 3.0
Liabilities:				
Commodity contracts	$ (28.0)	$ (11.0)	$ —	$ (39.0)
Foreign currency contracts	$ —	$ (1.5)	$ —	$ (1.5)
Interest rate contracts	$ —	$ (2.2)	$ —	$ (2.2)
Non-qualified supplemental postretirement grantor trust investments (a)	$ 35.2	$ —	$ —	$ 35.2
September 30, 2016:				
Derivative instruments:				
Assets:				
Commodity contracts	$ 28.9	$ 26.0	$ —	$ 54.9
Foreign currency contracts	$ —	$ 17.8	$ —	$ 17.8
Liabilities:				
Commodity contracts	$ (76.8)	$ (21.8)	$ —	$ (98.6)
Foreign currency contracts	$ —	$ (2.4)	$ —	$ (2.4)
Interest rate contracts	$ —	$ (3.9)	$ —	$ (3.9)
Cross-currency contracts	$ —	$ (0.5)	$ —	$ (0.5)
Non-qualified supplemental postretirement grantor trust investments (a)	$ 33.0	$ —	$ —	$ 33.0
March 31, 2016:				
Derivative instruments:				
Assets:				
Commodity contracts	$ 20.3	$ 16.7	$ —	$ 37.0
Foreign currency contracts	$ —	$ 11.6	$ —	$ 11.6
Liabilities:				
Commodity contracts	$ (59.0)	$ (48.4)	$ —	$ (107.4)
Foreign currency contracts	$ —	$ (5.0)	$ —	$ (5.0)
Interest rate contracts	$ —	$ (3.4)	$ —	$ (3.4)
Cross-currency contracts	$ —	$ (1.3)	$ —	$ (1.3)
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

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

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. 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). The carrying amount and estimated fair value of our long-term debt (including current maturities but excluding unamortized debt issuance costs) at March 31, 2017, September 30, 2016 and March 31, 2016 were as follows:

	March 31, 2017	September 30, 2016	March 31, 2016
Carrying amount	$ 4,238.9	$ 3,832.3	$ 3,639.0
Estimated fair value	$ 4,255.0	$ 4,052.3	$ 3,775.3

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. See Note 2 for additional information on this cost basis investment.

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

Regulated Utility Operations

Natural Gas

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. Gains and losses on Gas Utility's natural gas futures contracts and 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).

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

Electricity

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. At March 31, 2017, September 30, 2016 and March 31, 2016, substantially all Electric Utility forward electricity purchase contracts were subject to the NPNS exception.

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. Gains and losses on Electric Utility FTRs 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 DS mechanism (see Note 6).

Non-utility Operations

LPG

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 businesses 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. Also, Midstream & Marketing uses NYMEX futures contracts to economically hedge the gross margin associated with the purchase and anticipated later near-term sale of propane.

Natural Gas

In order to manage market price risk relating to fixed-price sales contracts for natural gas, Midstream & Marketing enters into NYMEX and over-the-counter natural gas futures and forward contracts and Intercontinental Exchange ("ICE") natural gas basis swap contracts. 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.

Electricity

In order to manage market price risk relating to fixed-price sales contracts for electricity, Midstream & Marketing enters into 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. From time to time, 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.

Interest Rate Risk

UGI France SAS's and Flaga GmbH's long-term debt agreements have interest rates that are generally indexed to short-term market interest rates. UGI France SAS and Flaga GmbH 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.

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").

We account for interest rate swaps and IRPAs as cash flow hedges. At March 31, 2017, 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 $3.5.

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

Foreign Currency Exchange Rate Risk

Forward Foreign Currency Exchange Contracts

In order to reduce exposure to foreign exchange rate volatility related to our foreign LPG operations, through September 30, 2016, we entered into forward foreign currency exchange contracts to hedge a portion of anticipated U.S. dollar-denominated LPG product purchases primarily during the heating-season months of October through March. We account for these foreign currency exchange contracts associated with anticipated purchases of U.S. dollar-denominated LPG as cash flow hedges. At March 31, 2017, 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 $9.4.

Beginning October 1, 2016, in order to reduce the volatility in net income associated with our foreign operations, principally as a result of changes in the U.S. dollar exchange rate between the euro and British pound sterling, we enter into forward foreign currency exchange contracts. The fair value of these forward foreign currency contracts are recorded as assets or liabilities on the Condensed Consolidated Balance Sheets. Changes in the fair value of these foreign currency exchange contracts are recorded in “(Losses) gains on foreign currency contracts, net” on the Condensed Consolidated Statements of Income.

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.

Cross-currency Swaps

From time to time, Flaga GmbH 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 floating U.S. dollar-denominated interest rate to a fixed euro-denominated interest rate. We designate these cross-currency swaps as cash flow hedges.

At March 31, 2017, the amount of net losses associated with such cross-currency swaps expected to be reclassified into earnings during the next twelve months is not material.

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

Quantitative Disclosures Related to Derivative Instruments

The following table summarizes by derivative type the gross notional amounts related to open derivative contracts as of March 31, 2017, September 30, 2016 and March 31, 2016, and the final settlement date of the Company's open derivative transactions as of March 31, 2017, excluding those derivatives that qualified for the NPNS exception:

			Notional Amounts (in millions)		
Type	Units	Settlements Extending Through	March 31, 2017	September 30, 2016	March 31, 2016
Commodity Price Risk:					
Regulated Utility Operations					
Gas Utility NYMEX natural gas futures and option contracts	Dekatherms	March 2018	9.0	18.4	10.0
Electric Utility forward electricity purchase contracts	Kilowatt hours	N/A	—	—	23.6
FTRs	Kilowatt hours	May 2017	14.6	58.3	69.2
Non-utility Operations					
LPG swaps & options	Gallons	September 2019	241.6	396.9	370.2
Natural gas futures, forward and pipeline contracts	Dekatherms	December 2021	56.5	71.1	84.7
Natural gas basis swap contracts	Dekatherms	December 2020	107.2	118.3	90.1
NYMEX natural gas storage	Dekatherms	March 2019	1.4	1.9	1.7
Electricity long forward and futures contracts	Kilowatt hours	May 2020	668.7	761.2	591.1
Electricity short forward and futures contracts	Kilowatt hours	May 2020	526.1	264.6	431.6
FTRs	Kilowatt hours	N/A	—	—	20.5
Interest Rate Risk:					
Interest rate swaps	Euro	October 2020	€ 645.8	€ 645.8	€ 645.8
Foreign Currency Exchange Rate Risk:					
Forward foreign currency exchange contracts	USD	September 2020	$ 321.8	$ 314.3	$ 262.5
Cross-currency swaps	USD	September 2018	$ 59.1	$ 59.1	$ 59.1

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 March 31, 2017, September 30, 2016 and March 31, 2016, restricted cash in brokerage accounts totaled $0.3, $15.6 and $40.0, respectively. Although we have concentrations of credit risk associated with derivative instruments, the maximum amount of loss we would incur if these counterparties failed to perform according to the terms of their contracts, based upon the gross fair values of the derivative instruments, was not material at March 31, 2017. 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 March 31, 2017, 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.

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 by type, as well as the effects of offsetting, as of March 31, 2017, September 30, 2016 and March 31, 2016:

	March 31, 2017	September 30, 2016	March 31, 2016
Derivative assets:			
Derivatives designated as hedging instruments:			
Foreign currency contracts	$ 14.2	$ 17.8	$ 11.6
Cross-currency contracts	3.0	—	—
	17.2	17.8	11.6
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	2.1	4.5	1.2
Derivatives not designated as hedging instruments:			
Commodity contracts	71.9	50.4	35.8
Foreign currency contracts	1.4	—	—
	73.3	50.4	35.8
Total derivative assets — gross	92.6	72.7	48.6
Gross amounts offset in the balance sheet	(31.8)	(35.0)	(26.4)
Cash collateral received	(0.2)	(0.3)	—
Total derivative assets — net	$ 60.6	$ 37.4	$ 22.2
Derivative liabilities:			
Derivatives designated as hedging instruments:			
Foreign currency contracts	$ —	$ (2.4)	$ (5.0)
Cross-currency contracts	—	(0.5)	(1.3)
Interest rate contracts	(2.2)	(3.9)	(3.4)
	(2.2)	(6.8)	(9.7)
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	(0.2)	(0.5)	(3.5)
Derivatives not designated as hedging instruments:			
Commodity contracts	(38.8)	(98.1)	(103.9)
Foreign currency contracts	(1.5)	—	—
	(40.3)	(98.1)	(103.9)
Total derivative liabilities — gross	(42.7)	(105.4)	(117.1)
Gross amounts offset in the balance sheet	31.8	35.0	26.4
Cash collateral pledged	—	—	0.1
Total derivative liabilities — net	$ (10.9)	$ (70.4)	$ (90.6)

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

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 for the three and six months ended March 31, 2017 and 2016:

Three Months Ended March 31,:

Cash Flow Hedges:	Gain (Loss) Recognized in AOCI 2017	Gain (Loss) Recognized in AOCI 2016	Gain (Loss) Reclassified from AOCI into Income 2017	Gain (Loss) Reclassified from AOCI into Income 2016	Location of Gain (Loss) Reclassified from AOCI into Income
Foreign currency contracts	$ (1.7)	$ (10.7)	$ 8.9	$ 8.1	Cost of sales
Cross-currency contracts	0.3	(0.3)	—	0.2	Interest expense/other operating income, net
Interest rate contracts	0.6	(37.2)	(1.0)	(1.3)	Interest expense
Total	$ (0.8)	$ (48.2)	$ 7.9	$ 7.0	

Derivatives Not Designated as Hedging Instruments:	Gain (Loss) Recognized in Income 2017	Gain (Loss) Recognized in Income 2016	Location of Gain (Loss) Recognized in Income
Commodity contracts	$ 22.0	$ (6.0)	Cost of sales
Commodity contracts	0.8	0.2	Revenues
Commodity contracts	0.1	—	Operating and administrative expenses
Foreign currency contracts	(1.2)	—	(Losses) gains on foreign currency contracts, net
Total	$ 21.7	$ (5.8)	

Six Months Ended March 31,:

Cash Flow Hedges:	Gain (Loss) Recognized in AOCI 2017	Gain (Loss) Recognized in AOCI 2016	Gain (Loss) Reclassified from AOCI into Income 2017	Gain (Loss) Reclassified from AOCI into Income 2016	Location of Gain (Loss) Reclassified from AOCI into Income
Foreign currency contracts	$ 15.5	$ (5.3)	$ 16.8	$ 17.2	Cost of sales
Cross-currency contracts	0.2	(0.3)	(0.3)	0.2	Interest expense/other operating income, net
Interest rate contracts	1.8	(31.6)	(2.0)	(1.9)	Interest expense
Total	$ 17.5	$ (37.2)	$ 14.5	$ 15.5	

Derivatives Not Designated as Hedging Instruments:	Gain (Loss) Recognized in Income 2017	Gain (Loss) Recognized in Income 2016	Location of Gain (Loss) Recognized in Income
Commodity contracts	$ 130.5	$ (52.2)	Cost of sales
Commodity contracts	0.9	1.8	Revenues
Commodity contracts	—	(0.1)	Operating and administrative expenses
Foreign currency contracts	0.1	—	(Losses) gains on foreign currency contracts, net
Total	$ 131.5	$ (50.5)	

For the three and six months ended March 31, 2017, the amounts of derivative gains or losses representing ineffectiveness were not material. For the three and six months ended March 31, 2016, the amounts of derivative gains or losses representing ineffectiveness were losses of $2.1 and $5.5, respectively, which were included in “Other operating income, net,” on the Condensed

(Currency in millions, except per share amounts)

Consolidated Statements of Income and were related to interest rate contracts at UGI France SAS. For the three and six months ended March 31, 2017 and 2016, the amounts of gains or losses recognized in income as a result of excluding derivatives from ineffectiveness testing were not material.

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 certain of these contracts have the requisite elements of a derivative instrument, 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 six months ended March 31, 2017 and 2016:

Three Months Ended March 31, 2017	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI — December 31, 2016	$ (28.1)	$ (5.6)	$ (183.1)	$ (216.8)
Other comprehensive (loss) income before reclassification adjustments (after-tax)	—	(0.5)	17.8	17.3
Amounts reclassified from AOCI:				
Reclassification adjustments (pre-tax)	0.7	(7.9)	—	(7.2)
Reclassification adjustments tax (expense) benefit	(0.3)	2.5	—	2.2
Reclassification adjustments (after-tax)	0.4	(5.4)	—	(5.0)
Other comprehensive income (loss) attributable to UGI	0.4	(5.9)	17.8	12.3
AOCI — March 31, 2017	$ (27.7)	$ (11.5)	$ (165.3)	$ (204.5)

Three Months Ended March 31, 2016	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI — December 31, 2015	$ (20.0)	$ 12.7	$ (135.6)	$ (142.9)
Other comprehensive (loss) income before reclassification adjustments (after-tax)	—	(29.7)	46.7	17.0
Amounts reclassified from AOCI and noncontrolling interests:				
Reclassification adjustments (pre-tax)	0.4	(7.0)	—	(6.6)
Reclassification adjustments tax (expense) benefit	(0.1)	2.7	—	2.6
Reclassification adjustments (after-tax)	0.3	(4.3)	—	(4.0)
Other comprehensive income (loss) attributable to UGI	0.3	(34.0)	46.7	13.0
AOCI — March 31, 2016	$ (19.7)	$ (21.3)	$ (88.9)	$ (129.9)

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

Six Months Ended March 31, 2017	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI — September 30, 2016	$ (29.1)	$ (13.4)	$ (112.2)	$ (154.7)
Other comprehensive income (loss) before reclassification adjustments (after-tax)	—	11.8	(53.1)	(41.3)
Amounts reclassified from AOCI:				
Reclassification adjustments (pre-tax)	2.3	(14.5)	—	(12.2)
Reclassification adjustments tax (expense) benefit	(0.9)	4.6	—	3.7
Reclassification adjustments (after-tax)	1.4	(9.9)	—	(8.5)
Other comprehensive income (loss) attributable to UGI	1.4	1.9	(53.1)	(49.8)
AOCI — March 31, 2017	$ (27.7)	$ (11.5)	$ (165.3)	$ (204.5)

Six Months Ended March 31, 2016	Postretirement Benefit Plans	Derivative Instruments	Foreign Currency	Total
AOCI — September 30, 2015	$ (20.4)	$ 11.2	$ (105.4)	$ (114.6)
Other comprehensive (loss) income before reclassification adjustments (after-tax)	—	(22.9)	16.5	(6.4)
Amounts reclassified from AOCI:				
Reclassification adjustments (pre-tax)	1.1	(15.5)	—	(14.4)
Reclassification adjustments tax (expense) benefit	(0.4)	5.9	—	5.5
Reclassification adjustments (after-tax)	0.7	(9.6)	—	(8.9)
Other comprehensive income (loss) attributable to UGI	0.7	(32.5)	16.5	(15.3)
AOCI — March 31, 2016	$ (19.7)	$ (21.3)	$ (88.9)	$ (129.9)

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

Note 14 — Segment Information

Our operations comprise four reportable segments generally based upon products sold, geographic location and regulatory environment. Our reportable segments comprise: (1) AmeriGas Propane; (2) UGI International; (3) Midstream & Marketing; and (4) UGI Utilities.

As a result of changes in the composition of information reported to our chief operating decision maker ("CODM"), effective October 1, 2016, we combined (1) our UGI France reportable segment with our Flaga & Other reportable segment, collectively referred to as "UGI International;" and (2) our Energy Services reportable segment with our Electric Generation reportable segment, collectively referred to as "Midstream & Marketing." In accordance with GAAP, prior-period amounts have been restated to reflect these changes.

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 2016 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 and certain foreign currency derivative instruments not associated with current-period transactions. Net gains and losses on commodity and certain foreign currency 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.

UGI CORPORATION AND SUBSIDIARIES

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

Three Months Ended March 31, 2017	Total	Eliminations	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other (b)
Revenues	$ 2,173.8	$ (95.8) (c)	$ 863.6	$ 620.7	$ 423.7	$ 360.0	$ 1.6
Cost of sales	$ 1,071.2	$ (94.9) (c)	$ 355.8	$ 313.1	$ 309.8	$ 164.5	$ 22.9
Segment profit:							
Operating income (loss)	$ 513.2	$ —	$ 227.3	$ 121.0	$ 82.1	$ 116.4	$ (33.6)
Income (loss) from equity investees	2.3	—	—	(0.1)	2.4	—	—
(Losses) gains on foreign currency contracts, net	(1.2)	—	—	0.1	—	—	(1.3)
Loss on extinguishment of debt	(22.1)	—	(22.1)	—	—	—	—
Interest expense	(55.8)	—	(40.0)	(4.8)	(0.7)	(10.3)	—
Income (loss) before income taxes	$ 436.4	$ —	$ 165.2	$ 116.2	$ 83.8	$ 106.1	$ (34.9)
Partnership Adjusted EBITDA (a)			$ 271.2				
Noncontrolling interests' net income (loss)	$ 91.9	$ —	$ 112.7	$ 0.1	$ —	$ —	$ (20.9)
Depreciation and amortization	$ 99.3	$ (0.1)	$ 45.0	$ 27.6	$ 8.8	$ 17.7	$ 0.3
Capital expenditures (including the effects of accruals)	$ 126.2	$ —	$ 27.2	$ 21.5	$ 20.8	$ 56.5	$ 0.2

Three Months Ended March 31, 2016 (d)	Total	Eliminations	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other (b)
Revenues	$ 1,972.1	$ (56.5) (c)	$ 827.5	$ 578.7	$ 298.8	$ 322.0	$ 1.6
Cost of sales	$ 776.9	$ (55.8) (c)	$ 298.2	$ 271.0	$ 189.7	$ 137.5	$ (63.7)
Segment profit:							
Operating income	$ 615.4	$ —	$ 250.4	$ 111.5	$ 77.8	$ 114.5	$ 61.2
Interest expense	(57.3)	—	(40.8)	(6.5)	(0.5)	(9.3)	(0.2)
Income before income taxes	$ 558.1	$ —	$ 209.6	$ 105.0	$ 77.3	$ 105.2	$ 61.0
Partnership Adjusted EBITDA (a)			$ 295.4				
Noncontrolling interests' net income	$ 174.8	$ —	$ 146.0	$ 0.1	$ —	$ —	$ 28.7
Depreciation and amortization	$ 100.7	$ (0.1)	$ 47.4	$ 28.3	$ 7.7	$ 17.0	$ 0.4
Capital expenditures (including the effects of accruals)	$ 114.5	$ —	$ 27.8	$ 22.3	$ 16.3	$ 48.1	$ —

Six Months Ended March 31, 2017	Total	Eliminations	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other (b)
Revenues	$ 3,853.3	$ (164.3) (c)	$ 1,540.8	$ 1,159.8	$ 693.5	$ 621.4	$ 2.1
Cost of sales	$ 1,718.6	$ (162.6) (c)	$ 616.5	$ 571.1	$ 501.6	$ 274.0	$ (82.0)
Segment profit:							
Operating income	$ 979.4	$ 0.1	$ 369.2	$ 209.9	$ 131.8	$ 198.6	$ 69.8
Income (loss) from equity investees	2.1	—	—	(0.3)	2.4	—	—
Gains (losses) on foreign currency contracts, net	0.1	—	—	0.2	—	—	(0.1)
Loss on extinguishments of debt	(55.3)	—	(55.3)	—	—	—	—
Interest expense	(111.2)	—	(80.0)	(9.6)	(1.3)	(20.3)	—
Income before income taxes	$ 815.1	$ 0.1	$ 233.9	$ 200.2	$ 132.9	$ 178.3	$ 69.7
Partnership Adjusted EBITDA (a)			$ 456.3				
Noncontrolling interests' net income (loss)	$ 152.1	$ —	$ 153.9	$ 0.3	$ —	$ —	$ (2.1)
Depreciation and amortization	$ 197.4	$ (0.1)	$ 89.6	$ 55.5	$ 16.8	$ 35.1	$ 0.5
Capital expenditures (including the effects of accruals)	$ 299.8	$ —	$ 53.6	$ 43.0	$ 82.3	$ 120.6	$ 0.3
As of March 31, 2017							
Total assets	$ 11,385.5	$ (58.6)	$ 4,238.1	$ 2,804.7	$ 1,200.7	$ 2,909.7	$ 290.9
Short-term borrowings	$ 50.1	$ —	$ —	$ 1.6	$ —	$ 48.5	$ —
Goodwill	$ 2,948.4	$ —	$ 1,981.2	$ 773.6	$ 11.5	$ 182.1	$ —

UGI CORPORATION AND SUBSIDIARIES

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

Six Months Ended March 31, 2016 (d)	Total	Eliminations		AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other (b)
Revenues	$ 3,578.7	$ (99.2)	(c)	$ 1,471.6	$ 1,156.9	$ 525.7	$ 520.0	$ 3.7
Cost of sales	$ 1,510.9	$ (97.6)	(c)	$ 541.4	$ 573.8	$ 344.2	$ 212.9	$ (63.8)
Segment profit:								
Operating income	$ 920.9	$ 0.1		$ 380.0	$ 196.6	$ 120.7	$ 162.8	$ 60.7
Loss from equity investees	(0.1)	—		—	(0.1)	—	—	—
Interest expense	(115.2)	—		(81.8)	(13.0)	(1.3)	(18.8)	(0.3)
Income before income taxes	$ 805.6	$ 0.1		$ 298.2	$ 183.5	$ 119.4	$ 144.0	$ 60.4
Partnership EBITDA (a)				$ 473.1				
Noncontrolling interests’ net income	$ 228.1	$ —		$ 203.3	$ 0.2	$ —	$ —	$ 24.6
Depreciation and amortization	$ 201.3	$ (0.1)		$ 96.6	$ 55.5	$ 15.1	$ 33.7	$ 0.5
Capital expenditures (including the effects of accruals)	$ 247.4	$ —		$ 55.8	$ 43.3	$ 38.7	$ 109.6	$ —
As of March 31, 2016								
Total assets	$ 10,925.8	$ (87.5)		$ 4,181.6	$ 3,066.2	$ 1,000.2	$ 2,639.5	$ 125.8
Short-term borrowings	$ 227.1	$ —		$ 65.3	$ 2.8	$ 4.0	$ 155.0	$ —
Goodwill	$ 2,998.6	$ —		$ 1,971.3	$ 833.7	$ 11.5	$ 182.1	$ —

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

	Three Months Ended March 31,		Six Months Ended March 31,	
	2017	2016	2017	2016
Partnership Adjusted EBITDA	$ 271.2	$ 295.4	$ 456.3	$ 473.1
Depreciation and amortization	(45.0)	(47.4)	(89.6)	(96.6)
Interest expense	(40.0)	(40.8)	(80.0)	(81.8)
Loss on extinguishments of debt	(22.1)	—	(55.3)	—
Noncontrolling interest (i)	1.1	2.4	2.5	3.5
Income before income taxes	$ 165.2	$ 209.6	$ 233.9	$ 298.2

(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 UGI’s corporate headquarters facility, and (2) UGI’s unallocated corporate and general expenses and interest income. Corporate & Other results also include the effects of net pre-tax (losses) gains on commodity and certain foreign currency derivative instruments not associated with current-period transactions (including such amounts attributable to noncontrolling interests) totaling $(23.9) and $64.0 during the three months ended March 31, 2017 and 2016, respectively, and $81.6 and $65.1 during the six months ended March 31, 2017 and 2016, respectively. Corporate & Other results for the three and six months ended March 31, 2017, also include a pre-tax loss of $7.0 associated with the impairment of a cost basis investment (see Note 2). Corporate & Other assets principally comprise cash and cash equivalents 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) Restated to reflect (1) the current-year changes in the presentation of our UGI International and Midstream & Marketing reportable segments and (2) the adoption of new accounting guidance related to debt issuance costs (see Note 2).

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 ("LPG"), oil, electricity, and natural gas and the capacity to transport product to our customers; (3) changes in domestic and foreign laws and regulations, including safety, tax, consumer protection, environmental 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) customer, counterparty, supplier, or vendor defaults; (12) liability for uninsured claims and for claims in excess of insurance coverage, including those for personal injury and property damage arising from explosions, terrorism, and other catastrophic events that may result from operating hazards and risks incidental to generating and distributing electricity and transporting, storing and distributing natural gas and LPG; (13) transmission or distribution system service interruptions; (14) political, regulatory and economic conditions in the United States and in foreign countries, including the current conflicts in the Middle East, and foreign currency exchange rate fluctuations, particularly the euro; (15) capital market conditions, including reduced access to capital markets and interest rate fluctuations; (16) changes in commodity market prices resulting in significantly higher cash collateral requirements; (17) reduced distributions from subsidiaries impacting the ability to pay dividends; (18) changes in Marcellus Shale gas production; (19) the availability, timing and success of our acquisitions, commercial initiatives and investments to grow our businesses; (20) our ability to successfully integrate acquired businesses and achieve anticipated synergies; and (21) the interruption, disruption, failure, malfunction, or breach of our information technology systems, including due to cyber attack.

These factors, and those factors set forth in Item 1A. Risk Factors in the Company's 2016 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 March 31, 2017 ("2017 three-month period") with the three months ended March 31, 2016 ("2016 three-month period") and the six months ended March 31, 2017 ("2017 six-month period") with the six months ended March 31, 2016 ("2016 six-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.

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 Corporation" and "adjusted diluted earnings per share," both of which are non-GAAP financial measures, when evaluating UGI's overall performance. Management believes that these non-GAAP measures provide meaningful information to investors. Adjusted net income attributable to UGI Corporation excludes (1) net after-tax gains and losses on commodity and certain foreign currency 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). UGI does not designate its commodity and certain foreign currency derivative instruments as hedges under U.S. generally accepted accounting principles ("GAAP"). Volatility in net income attributable to UGI Corporation as determined in accordance with GAAP can occur as a result of gains and losses on commodity and certain foreign currency 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 and certain foreign currency 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. For further information, see "Non-GAAP Financial Measures" below.

Executive Overview

Three Months Ended March 31, 2017 Results

We recorded GAAP net income attributable to UGI Corporation for the 2017 three-month period of $219.9 million (equal to $1.24 per diluted share), compared to GAAP net income attributable to UGI Corporation for the 2016 three-month period of $233.2 million (equal to $1.33 per diluted share). GAAP net income attributable to UGI in the 2017 three-month period includes net after-tax losses on commodity derivative instruments not associated with current-period transactions of $3.1 million (equal to $0.02 per diluted share) and net after-tax unrealized losses on certain foreign currency derivative instruments of $0.8 million (equal to $0.01 per diluted share). GAAP net income attributable to UGI in the 2016 three-month period includes net after-tax gains on commodity derivative instruments not associated with current-period transactions of $22.4 million (equal to $0.12 per diluted share). GAAP net income attributable to UGI in the 2017 and 2016 three-month periods also reflect net after-tax integration expenses associated with Finagaz, which decreased net income attributable to UGI by $4.4 million (equal to $0.02 per diluted share) and $5.4 million (equal to $0.03 per diluted share), respectively. GAAP net income attributable to UGI Corporation in the 2017 three-month period also includes an after-tax loss on an extinguishment of debt at AmeriGas Propane of $3.6 million (equal to $0.02 per diluted share).

Adjusted net income attributable to UGI Corporation for the 2017 three-month period was $231.8 million (equal to $1.31 per diluted share) compared to $216.2 million (equal to $1.24 per diluted share) in the 2016 three-month period. The 2017 three-month period adjusted net income attributable to UGI principally reflects the net effects of (1) an $11.6 million increase in adjusted net income from UGI International; (2) a $4.4 million increase in adjusted net income from Midstream & Marketing; (3) a $1.9 million increase in adjusted net income from UGI Utilities; and (4) a $3.7 million decrease in adjusted net income attributable to UGI from AmeriGas Propane. Average temperatures based upon heating degree days were significantly warmer than normal at each of our domestic business units and modestly warmer than normal in Europe. The warmer than normal temperatures reduced heating-related sales volumes in all of our business units and, at our Midstream & Marketing unit, also reduced natural gas commodity unit margins and opportunities to benefit from locational basis differences between Marcellus and non-Marcellus delivery points. Compared to the prior-year three-month period, average temperatures in Europe were slightly colder while average temperatures in our domestic business units were warmer. In particular, temperatures during the critical heating-season months of January and February 2017 were significantly warmer than January and February 2016. UGI Utilities 2017 three-month period results reflect the impact of an increase in UGI Gas base rates effective October 19, 2016.

Six Months Ended March 31, 2017 Results

We recorded GAAP net income attributable to UGI Corporation for the 2017 six-month period of $450.6 million (equal to $2.55 per diluted share), compared to GAAP net income attributable to UGI Corporation for the 2016 six-month period of $347.8 million (equal to $1.99 per diluted share). GAAP net income attributable to UGI in the 2017 six-month period includes net after-tax gains on commodity derivative instruments not associated with current-period transactions of $49.1 million (equal to $0.28 per diluted share). GAAP net income attributable to UGI in the 2016 six-month period includes net after-tax gains on commodity derivative instruments not associated with current-period transactions of $26.0 million (equal to $0.15 per diluted share). GAAP net income attributable to UGI in the 2017 and 2016 six-month periods also reflect net after-tax integration expenses associated with Finagaz, which decreased net income attributable to UGI by $9.7 million (equal to $0.05 per diluted share) and $6.8 million (equal to $0.04 per diluted share), respectively. GAAP net income attributable to UGI Corporation in the 2017 six-month period also includes (1) an after-tax loss on extinguishments of debt at AmeriGas Propane of $8.9 million (equal to $0.05 per diluted share) and (2) a decrease in net deferred income tax liabilities of $27.4 million (equal to $0.15 per diluted share) resulting from a change in the French corporate income tax rate enacted in December 2016 that will become effective in Fiscal 2021.

Adjusted net income attributable to UGI for the 2017 six-month period was $392.7 million (equal to $2.22 per diluted share) compared to $328.6 million (equal to $1.88 per diluted share) for the 2016 six-month period. The 2017 six-month period adjusted net income attributable to UGI principally reflects the net effects of (1) a $30.0 million increase in adjusted net income from UGI International; (2) a $22.8 million increase in adjusted net income from UGI Utilities; (3) a $9.7 million increase in adjusted net income from Midstream & Marketing; and (4) a $0.4 million decrease in adjusted net income attributable to UGI from AmeriGas

Propane. Although average temperatures were warmer than normal at each of our domestic business units and approximately normal at our UGI International business in Europe, average temperatures were colder than the significantly warmer-than-normal weather experienced in the prior-year six-month period. UGI Utilities' 2017 six-month period results reflect the impact of an increase in UGI Gas base rates effective October 19, 2016.

Although the British pound sterling during the 2017 three- and six-month periods was nearly 15% weaker than in the same periods in the prior year, and the euro was slightly weaker, the effects of these weaker currencies did not negatively impact UGI International's 2017 three-month and six-month net income due to gains on foreign currency exchange contracts.

We believe each of our business units has sufficient liquidity in the form of revolving credit facilities and, with respect to Midstream & Marketing, also an accounts receivable securitization facility, to fund business operations during Fiscal 2017 (see "Financial Condition and Liquidity").

Non-GAAP Financial Measures

As previously mentioned, UGI management uses "adjusted net income attributable to UGI Corporation" and "adjusted diluted earnings per share," both of which are non-GAAP financial measures, when evaluating UGI's overall performance. For the 2017 and 2016 three- and six-month periods, adjusted net income attributable to UGI Corporation is net income attributable to UGI after excluding net after-tax gains and losses on commodity and certain foreign currency derivative instruments not associated with current-period transactions (principally comprising changes in unrealized gains and losses on such derivative instruments), Finagaz integration expenses, loss associated with extinguishments of debt and the impact on net deferred income tax liabilities from a change in the French tax rate.

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 and certain foreign currency 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 tables reconcile consolidated net income attributable to UGI Corporation, the most directly comparable GAAP measure, to adjusted net income attributable to UGI Corporation, and reconcile diluted earnings per share, the most comparable GAAP measure, to adjusted diluted earnings per share, to reflect the adjustments referred to above:

Three Months Ended March 31, 2017	Total	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other
Adjusted net income attributable to UGI Corporation (millions):						
Net income (loss) attributable to UGI Corporation	$ 219.9	$ 32.0	$ 79.3	$ 50.2	$ 65.1	$ (6.7)
Net losses on commodity derivative instruments not associated with current-period transactions (net of tax of $1.5) (a)	3.1	—	—	—	—	3.1
Unrealized losses on foreign currency derivative instruments (net of tax of $(0.5)) (a)	0.8	—	—	—	—	0.8
Loss on extinguishment of debt (net of tax of $(2.3)) (a)	3.6	3.6	—	—	—	—
Integration expenses associated with Finagaz (net of tax of $(2.3)) (a)	4.4	—	4.4	—	—	—
Adjusted net income (loss) attributable to UGI Corporation	$ 231.8	$ 35.6	$ 83.7	$ 50.2	$ 65.1	$ (2.8)
Adjusted diluted earnings per share:						
UGI Corporation earnings (loss) per share — diluted	$ 1.24	$ 0.18	$ 0.45	$ 0.28	$ 0.37	$ (0.04)
Net losses on commodity derivative instruments not associated with current-period transactions	0.02	—	—	—	—	0.02
Unrealized losses on foreign currency derivative instruments (b)	0.01	—	—	—	—	0.01
Loss on extinguishment of debt	0.02	0.02	—	—	—	—
Integration expenses associated with Finagaz	0.02	—	0.02	—	—	—
Adjusted diluted earnings (loss) per share	$ 1.31	$ 0.20	$ 0.47	$ 0.28	$ 0.37	$ (0.01)

UGI CORPORATION AND SUBSIDIARIES

Three Months Ended March 31, 2016	Total	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other
Adjusted net income attributable to UGI Corporation (millions):						
Net income attributable to UGI Corporation	$ 233.2	$ 39.3	$ 66.7	$ 45.8	$ 63.2	$ 18.2
Net gains on commodity derivative instruments not associated with current-period transactions (net of tax of $12.9) (a)	(22.4)	—	—	—	—	(22.4)
Integration expenses associated with Finagaz (net of tax of $(3.2)) (a)	5.4	—	5.4	—	—	—
Adjusted net income (loss) attributable to UGI Corporation	$ 216.2	$ 39.3	$ 72.1	$ 45.8	$ 63.2	$ (4.2)
Adjusted diluted earnings per share:						
UGI Corporation earnings per share — diluted	$ 1.33	$ 0.22	$ 0.38	$ 0.26	$ 0.36	$ 0.11
Net gains on commodity derivative instruments not associated with current-period transactions (b)	(0.12)	—	—	—	—	(0.12)
Integration expenses associated with Finagaz	0.03	—	0.03	—	—	—
Adjusted diluted earnings (loss) per share	$ 1.24	$ 0.22	$ 0.41	$ 0.26	$ 0.36	$ (0.01)

Six Months Ended March 31, 2017	Total	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other
Adjusted net income attributable to UGI Corporation (millions):						
Net income attributable to UGI Corporation	$ 450.6	$ 48.6	$ 167.6	$ 80.1	$ 109.4	$ 44.9
Net gains on commodity derivative instruments not associated with current-period transactions (net of tax of $34.8) (a)	(49.1)	—	—	—	—	(49.1)
Loss on extinguishments of debt (net of tax of $(5.7)) (a)	8.9	8.9	—	—	—	—
Integration expenses associated with Finagaz (net of tax of $(5.1)) (a)	9.7	—	9.7	—	—	—
Impact from change in French tax rate	(27.4)	—	(27.4)	—	—	—
Adjusted net income (loss) attributable to UGI Corporation	$ 392.7	$ 57.5	$ 149.9	$ 80.1	$ 109.4	$ (4.2)
Adjusted diluted earnings per share:						
UGI Corporation earnings per share — diluted	$ 2.55	$ 0.27	$ 0.95	$ 0.45	$ 0.62	$ 0.26
Net gains on commodity derivative instruments not associated with current-period transactions	(0.28)	—	—	—	—	(0.28)
Loss on extinguishments of debt	0.05	0.05	—	—	—	—
Integration expenses associated with Finagaz	0.05	—	0.05	—	—	—
Impact from change in French tax rate	(0.15)	—	(0.15)	—	—	—
Adjusted diluted earnings (loss) per share	$ 2.22	$ 0.32	$ 0.85	$ 0.45	$ 0.62	$ (0.02)

Six Months Ended March 31, 2016	Total	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Corporate & Other
Adjusted net income attributable to UGI Corporation (millions):						
Net income attributable to UGI Corporation	$ 347.8	$ 57.9	$ 113.1	$ 70.4	$ 86.6	$ 19.8
Net gains on commodity derivative instruments not associated with current-period transactions (net of tax of $14.4) (a)	(26.0)	—	—	—	—	(26.0)
Integration expenses associated with Finagaz (net of tax of $(4.1)) (a)	6.8	—	6.8	—	—	—
Adjusted net income (loss) attributable to UGI Corporation	$ 328.6	$ 57.9	$ 119.9	$ 70.4	$ 86.6	$ (6.2)
Adjusted diluted earnings per share:						
UGI Corporation earnings per share — diluted	$ 1.99	$ 0.33	$ 0.65	$ 0.40	$ 0.49	$ 0.12
Net gains on commodity derivative instruments not associated with current-period transactions	(0.15)	—	—	—	—	(0.15)
Integration expenses associated with Finagaz	0.04	—	0.04	—	—	—
Adjusted diluted earnings (loss) per share	$ 1.88	$ 0.33	$ 0.69	$ 0.40	$ 0.49	$ (0.03)

(a) Income taxes associated with pre-tax adjustments determined using statutory business unit tax rates.
(b) Includes the effects of rounding.

RESULTS OF OPERATIONS

2017 Three-Month Period compared to the 2016 Three-Month Period

Net Income Attributable to UGI Corporation by Business Unit

For the three months ended March 31,	2017		2016		Variance - Favorable (Unfavorable)	
(Dollars in millions)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane (a)	$ 32.0	14.6 %	$ 39.3	16.9%	$ (7.3)	(18.6)%
UGI International (b)	79.3	36.1 %	66.7	28.6%	12.6	18.9 %
Midstream & Marketing	50.2	22.8 %	45.8	19.6%	4.4	9.6 %
UGI Utilities	65.1	29.6 %	63.2	27.1%	1.9	3.0 %
Corporate & Other (c) (d)	(6.7)	(3.1)%	18.2	7.8%	(24.9)	N.M.
Net income attributable to UGI Corporation	$ 219.9	100.0 %	$ 233.2	100.0%	$ (13.3)	(5.7)%

(a) Three months ended March 31, 2017, includes a net after-tax loss of $3.6 million from an extinguishment of debt (see Note 8 to condensed consolidated financial statements).
(b) Includes after-tax integration expenses associated with Finagaz of $4.4 million and $5.4 million for the three months ended March 31, 2017 and 2016, respectively.
(c) Includes net after-tax (losses) gains on commodity derivative instruments not associated with current-period transactions of $(3.1) million and $22.4 million for the three months ended March 31, 2017 and 2016, respectively, and in the 2017 three-month period, after-tax unrealized losses on certain foreign currency derivative instruments of $0.8 million.
(d) Three months ended March 31, 2017, includes a $4.5 million after-tax loss associated with the impairment of a cost basis investment. See Note 2 to condensed consolidated financial statements.
N.M. — Variance is not meaningful.

AmeriGas Propane

For the three months ended March 31,		2017		2016		Increase (Decrease)	
(Dollars in millions)							
Revenues	$	863.6	$	827.5	$	36.1	4.4 %
Total margin (a)	$	507.8	$	529.3	$	(21.5)	(4.1)%
Partnership operating and administrative expenses	$	240.0	$	238.5	$	1.5	0.6 %
Partnership Adjusted EBITDA (b)	$	271.2	$	295.4	$	(24.2)	(8.2)%
Operating income (c)	$	227.3	$	250.4	$	(23.1)	(9.2)%
Retail gallons sold (millions)		362.7		385.8		(23.1)	(6.0)%
Heating degree days—% (warmer) than normal (d)		(13.3)%		(11.7)%		—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the three months ended March 31, 2017 and 2016, excludes net pre-tax (losses) gains of $(28.6) million and $39.5 million, respectively, on AmeriGas Propane commodity derivative instruments not associated with current-period transactions.
(b) Partnership Adjusted EBITDA should not be considered as an alternative to net income (as an indicator of operating performance) and is not a measure of performance or financial condition under GAAP. Management uses Partnership Adjusted EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 14 to condensed consolidated financial statements).
(c) Operating income reflects certain operating and administrative expenses of the General Partner.
(d) 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.

AmeriGas Propane's retail gallons sold during the 2017 three-month period decreased 6.0% compared with the prior-year period. The decrease in retail gallons sold reflects average temperatures that were 13.3% warmer than normal and 2.9% warmer than the prior-year period. Temperatures during the critical heating season months of January and February were more than 9% warmer than in the same period of the prior year and, during the 2017 three-month period, average temperatures east of the Rocky Mountains, where the Partnership has a greater proportion of temperature-sensitive volumes, were substantially warmer than during the 2016 three-month period.

Retail propane revenues increased $31.8 million during the 2017 three-month period reflecting the effects of higher average retail selling prices ($76.7 million) partially offset by the lower retail volumes sold ($44.9 million). Wholesale propane revenues increased $4.8 million during the 2017 three-month period reflecting the effects of higher average wholesale selling prices ($5.1 million) partially offset by lower wholesale volumes sold ($0.3 million). Average daily wholesale propane commodity prices during the 2017 three-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 85% higher than such prices in the 2016 three-month period during which prior-year period prices were at recent historic lows. Other revenues in the 2017 three-month period were about equal to the prior-year period. AmeriGas Propane total cost of sales increased $57.6 million principally reflecting the effects of higher Partnership average propane product costs ($74.1 million) partially offset by the effects of the lower volumes sold ($16.5 million).

AmeriGas Propane total margin decreased $21.5 million in the 2017 three-month period principally reflecting lower retail propane total margin ($20.7 million). The decrease in retail propane total margin principally reflects the lower retail volumes sold partially offset by slightly higher average retail unit margin.

Partnership Adjusted EBITDA decreased $24.2 million in the 2017 three-month period principally reflecting the effects of the lower adjusted total margin ($21.5 million) and slightly higher Partnership operating and administrative expenses ($1.5 million). Partnership operating and administrative expenses increased reflecting, among other things, higher vehicle expenses ($4.0 million) including higher vehicle fuel expenses, and higher general insurance and self-insured casualty and liability expenses ($2.3 million) partially offset by lower employee group insurance expenses ($4.3 million). AmeriGas Propane operating income decreased $23.1 million in the 2017 three-month period principally reflecting the $24.2 million decrease in Partnership Adjusted EBITDA partially offset by lower depreciation and amortization expense ($2.4 million).

During the 2017 three-month period, AmeriGas Partners recognized a pre-tax loss of $22.1 million associated with an early repayment of $378.3 million principal amount of AmeriGas Partners' 7.00% Senior Notes comprising early redemption premiums and the write-off of unamortized debt issuance costs. Net income attributable to UGI reflects an after-tax loss of $3.6 million associated with this early extinguishment of debt (see Note 8 to condensed consolidated financial statements).

UGI International

For the three months ended March 31,	2017	2016	Increase (Decrease)	
(Dollars in millions)				
Revenues	$ 620.7	$ 578.7	$ 42.0	7.3 %
Total margin (a)	$ 307.6	$ 307.7	$ (0.1)	— %
Operating and administrative expenses (b)	$ 159.6	$ 166.4	$ (6.8)	(4.1)%
Operating income (b)	$ 121.0	$ 111.5	$ 9.5	8.5 %
Income before income taxes (b) (c)	$ 116.2	$ 105.0	$ 11.2	10.7 %
Retail gallons sold (millions) (d)	253.1	240.5	12.6	5.2 %
UGI International degree days—% (warmer) than normal (e)	(6.2)%	(7.4)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the three months ended March 31, 2017 and 2016 excludes net pre-tax (losses) gains of $(17.4) million and $13.0 million, respectively, on UGI International commodity derivative instruments not associated with current-period transactions.
(b) Reflects impacts of Finagaz integration expenses for the three months ended March 31, 2017 and 2016, of $6.7 million and $8.6 million, respectively.
(c) Income before income taxes for the three months ended March 31, 2017, excludes pre-tax unrealized losses on certain foreign currency derivative instruments of $1.3 million.
(d) Excludes retail gallons from our LPG business in China, which was sold in March 2016.
(e) Deviation from average heating degree days primarily for the 30-year period 1981-2010 at locations in our UGI International service territories.

Average temperatures during the 2017 three-month period at UGI International were 6.2% warmer than normal but 1.3% colder than the prior-year period. Total retail gallons sold during the 2017 three-month period were higher than the prior-year period principally reflecting the effects of the colder weather. During the 2017 three-month period, average wholesale commodity prices for propane and butane in northwest Europe were approximately 70% higher than in the prior-year period during which prior-year period LPG prices were at recent historic lows.

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 2017 and 2016 three-month periods, the average un-weighted euro-to-dollar translation rates were approximately $1.07 and $1.09, respectively, and the average un-weighted British pound sterling-to-dollar translation rates were approximately $1.25 and $1.42, respectively. The effects of these weaker currencies did not negatively impact UGI International net income due to gains on foreign currency exchange contracts.

UGI International revenues increased $42.0 million during the 2017 three-month period principally reflecting the impact of the higher retail gallons sold and higher LPG selling prices partially offset by the translation impact of the weaker British pound sterling and the euro. UGI International cost of sales increased $42.1 million during the 2017 three-month period principally reflecting the higher retail gallons sold and higher average LPG commodity prices partially offset by the translation impact on cost of sales from the weaker British pound sterling and the euro.

UGI International total margin was about equal to the prior year as the effect of higher retail sales was offset by slightly lower average retail bulk and cylinder LPG unit margins and the translation impact of the weaker currencies. The slightly lower average retail bulk and cylinder LPG unit margins principally reflect the effects of higher LPG commodity costs during the 2017 three-month period.

The $9.5 million increase in UGI International operating income principally reflects a $6.8 million decrease in operating and administrative expenses and slightly higher other operating income. The decrease in operating and administrative expenses principally reflects the translation effects of the weaker British pound sterling and euro in the current-year period and lower Finagaz integration expenses. Operating and administrative expenses include $6.7 million and $8.6 million of Finagaz integration expenses in the 2017 and 2016 three-month periods, respectively. The higher other operating income reflects, in part, the absence of a $2.1 million loss recorded during the prior-year period associated with interest rate hedge ineffectiveness. UGI International income before income taxes increased $11.2 million principally reflecting the previously mentioned $9.5 million increase in UGI International operating income and slightly lower interest expense principally due to a lower 2017 three-month period interest rate on UGI France SAS’s €600 million Senior Facilities Agreement term loan.

Midstream & Marketing

For the three months ended March 31,	2017		2016		Increase		
(Dollars in millions)							
Revenues	$	423.7	$	298.8	$	124.9	41.8%
Total margin (a)	$	113.9	$	109.1	$	4.8	4.4%
Operating and administrative expenses	$	24.0	$	23.6	$	0.4	1.7%
Operating income	$	82.1	$	77.8	$	4.3	5.5%
Income before income taxes	$	83.8	$	77.3	$	6.5	8.4%

(a) Total margin represents total revenues less total cost of sales. Total margin for the three months ended March 31, 2017 and 2016 excludes net pre-tax gains of $23.4 million and $11.6 million, respectively, on Midstream & Marketing commodity derivative instruments not associated with current-period transactions.

Temperatures across Midstream & Marketing's energy marketing territory averaged 14.6% warmer than normal and 5% warmer than in the prior-year period. Midstream & Marketing's 2017 three-month period revenues were $124.9 million higher than in the 2016 three-month period principally reflecting higher natural gas revenues ($118.1 million) and, to a much lesser extent, higher peaking revenues ($8.0 million) and capacity management revenues ($3.1 million). The increase in natural gas revenues principally reflects higher natural gas prices and higher volumes on customer growth while the increase in peaking revenues reflects an increase in the number of contracts. These increases in revenues were partially offset principally by lower electric generation revenues. Midstream & Marketing cost of sales were $309.8 million in the 2017 three-month period compared to $189.7 million in the 2016 three-month period, an increase of $120.1 million, principally reflecting higher natural gas cost of sales ($117.0 million) primarily a result of the higher natural gas prices and volumes.

Notwithstanding the warmer temperatures in the 2017 three-month period, Midstream & Marketing total margin increased $4.8 million in the 2017 three-month period principally reflecting higher peaking total margin ($6.6 million), higher capacity management total margin ($3.1 million) and slightly higher natural gas total margin ($1.0 million) from higher sales. The increase in peaking total margin reflects an increase in the number of contracts while the increase in capacity management total margin reflects slightly higher prices for pipeline capacity. These increases in total margin were partially offset primarily by lower electric generation total margin ($2.8 million), reflecting lower electricity generation volumes and lower capacity revenue, and a decrease in margin from storage services.

Midstream & Marketing operating income and income before income taxes during the 2017 three-month period increased $4.3 million and $6.5 million, respectively. The increase in operating income principally reflects the previously mentioned increase in total margin ($4.8 million) and a slight increase in other operating income ($0.9 million) partially offset by slightly higher total operating and administrative expenses ($0.4 million) and higher depreciation expenses ($1.1 million). The slight increase in total operating and administrative expenses reflects higher wages and benefits expenses, which were offset in large part by lower Conemaugh and Hunlock electricity generating station operating and maintenance expenses, while the increase in depreciation primarily reflects incremental depreciation from the expansion of our natural gas pipeline and peaking assets. The increase in income before income taxes in the 2017 three-month period principally reflects the higher operating income and $2.4 million of income from our PennEast pipeline equity investment reflecting income from allowance for funds used during construction ("AFUDC").

UGI Utilities

For the three months ended March 31,	2017	2016	Increase (Decrease)	
(Dollars in millions)				
Revenues	$ 360.0	$ 322.0	$ 38.0	11.8 %
Total margin (a)	$ 194.2	$ 183.2	$ 11.0	6.0 %
Operating and administrative expenses	$ 57.6	$ 48.9	$ 8.7	17.8 %
Operating income	$ 116.4	$ 114.5	$ 1.9	1.7 %
Income before income taxes	$ 106.1	$ 105.2	$ 0.9	0.9 %
Gas Utility system throughput—billions of cubic feet (“bcf”)				
Core market	33.8	34.0	(0.2)	(0.6)%
Total	81.8	72.1	9.7	13.5 %
Electric Utility distribution sales - millions of kilowatt hours (“gwh”)	260.5	265.2	(4.7)	(1.8)%
Gas Utility heating degree days—% (warmer) than normal (b)	(11.7)%	(9.7)%	—	—

(a) Total margin represents total revenues less total cost of sales and revenue-related taxes, i.e., Electric Utility gross receipts taxes, of $1.2 million and $1.3 million during the three months ended March 31, 2017 and 2016, respectively. For financial statement purposes, revenue-related taxes are included in “utility taxes other than income taxes” on 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 three months ended March 31, 2017 were 11.7% warmer than normal and 3.3% warmer than during the three months ended March 31, 2016. Gas Utility core market volumes decreased 0.2 bcf (0.6%) principally reflecting the effects of the warmer 2017 three-month period weather offset by growth in the number of core market customers. Total Gas Utility distribution system throughput increased 9.7 bcf reflecting significantly higher large firm delivery service volumes principally associated with service to a new natural gas-fired generation facility partially offset by the lower 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 others. Electric Utility kilowatt-hour sales were 1.8% lower than in the prior-year period principally reflecting the impact of the warmer weather on Electric Utility heating-related sales.

UGI Utilities revenues increased $38.0 million principally reflecting higher Gas Utility revenues. The higher Gas Utility revenues reflect an increase in core market revenues ($24.4 million), higher large firm delivery service revenues ($4.8 million) and higher off-system sales revenues ($10.0 million). The $24.4 million increase in Gas Utility core market revenues principally reflects the effects of higher average retail core market PGC rates ($18.0 million) and an increase in UGI Gas base rates that became effective on October 19, 2016 ($8.7 million) partially offset by the lower core market throughput ($1.7 million). 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 total margin. UGI Utilities cost of sales was $164.5 million for the three-months ended March 31, 2017, compared with $137.5 million for the three months ended March 31, 2016, primarily reflecting the effects of higher average retail core market PGC rates ($18.0 million) and higher cost of sales associated with Gas Utility off-system sales ($10.0 million).

UGI Utilities total margin increased $11.0 million principally reflecting higher total margin from Gas Utility core market customers ($7.1 million) and higher large firm delivery service total margin ($3.2 million). The increase in Gas Utility core market margin reflects the increase in UGI Gas base rates ($8.7 million) partially offset by the effects of the lower core market throughput ($1.6 million). Electric Utility total margin was comparable to the prior-year three-month period.

UGI Utilities operating income increased $1.9 million principally reflecting the increase in total margin ($11.0 million) offset by higher operating and administrative expenses ($8.7 million) and higher depreciation and amortization expenses ($0.7 million). Operating and administrative expenses in the prior-year three-month period were reduced by the capitalization of $5.8 million of development stage costs associated with an information technology (“IT”) project that had been expensed in prior periods but qualified for capitalization during the 2016 three-month period. UGI Utilities operating and administrative expenses also include higher pension and postretirement benefits expense and Electric Utility distribution system expenses totaling $1.6 million. UGI Utilities income before income taxes increased $0.9 million reflecting the increase in UGI Utilities operating income ($1.9 million) partially offset by slightly higher interest expense.

Interest Expense and Income Taxes

Our consolidated interest expense during the 2017 three-month period was $55.8 million, $1.5 million lower than the $57.3 million of interest expense recorded during the 2016 three-month period. The lower interest expense principally reflects lower average interest rates on long-term debt at UGI International and AmeriGas Propane, and lower credit agreement borrowings at AmeriGas Propane. These decreases were partially offset by the effects of higher long-term debt outstanding at AmeriGas Propane and UGI Utilities.

Our effective income tax rate as a percentage of pre-tax income (excluding the effects on such rate of pre-tax income associated with noncontrolling interests not subject to federal income taxes) was 36.2% in the 2017 three-month period compared to 39.2% in the 2016 three-month period. The lower 2017 three-month period effective income tax rate is due primarily to the impact of excess tax benefits on share-based payments of $4.8 million resulting from the adoption of new accounting guidance on share-based payments effective October 1, 2016 (see Note 3 to condensed consolidated financial statements) and a higher proportion of pre-tax earnings associated with our UGI International operations, which have a lower effective tax rate than our domestic U.S. operations.

2017 Six-Month Period compared to the 2016 Six-Month Period

Net Income Attributable to UGI Corporation by Business Unit

For the six months ended March 31,	2017		2016		Variance - Favorable (Unfavorable)	
(Dollars in millions)	Amount	% of Total	Amount	% of Total	Amount	% Change
AmeriGas Propane (a)	$ 48.6	10.8%	$ 57.9	16.6%	$ (9.3)	(16.1)%
UGI International (b)(c)	167.6	37.2%	113.1	32.5%	54.5	48.2 %
Midstream & Marketing	80.1	17.8%	70.4	20.2%	9.7	13.8 %
UGI Utilities	109.4	24.3%	86.6	24.9%	22.8	26.3 %
Corporate & Other (d) (e)	44.9	9.9%	19.8	5.8%	25.1	N.M.
Net income attributable to UGI Corporation	$ 450.6	100.0%	$ 347.8	100.0%	$ 102.8	29.6 %

(a) Six months ended March 31, 2017, includes a net after-tax loss of $8.9 million from extinguishments of debt (see Note 8 to condensed consolidated financial statements).
(b) Six months ended March 31, 2017, includes beneficial impact of a $27.4 million adjustment to net deferred income tax liabilities associated with a change in French income tax rate (see Note 2 to condensed consolidated financial statements) and an income tax settlement refund of $6.7 million, plus interest, in France.
(c) Includes after-tax integration expenses associated with Finagaz of $9.7 million and $6.8 million for the six months ended March 31, 2017 and 2016, respectively.
(d) Includes net after-tax gains on commodity derivative instruments not associated with current-period transactions of $49.1 million and $26.0 million for the six months ended March 31, 2017 and 2016, respectively.
(e) Six months ended March 31, 2017, includes a $4.5 million after-tax loss associated with the impairment of a cost basis investment. See Note 2 to condensed consolidated financial statements.
N.M. — Variance is not meaningful.

AmeriGas Propane

For the six months ended March 31,	2017		2016		Increase (Decrease)		
(Dollars in millions)							
Revenues	$	1,540.8	$	1,471.6	$	69.2	4.7 %
Total margin (a)	$	924.3	$	930.2	$	(5.9)	(0.6)%
Partnership operating and administrative expenses	$	466.8	$	469.4	$	(2.6)	(0.6)%
Partnership Adjusted EBITDA (b)(c)	$	456.3	$	473.1	$	(16.8)	(3.6)%
Operating income (c) (d)	$	369.2	$	380.0	$	(10.8)	(2.8)%
Retail gallons sold (millions)		668.4		680.9	$	(12.5)	(1.8)%
Heating degree days—% (warmer) than normal (e)		(13.6)%		(15.2)%		—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the six months ended March 31, 2017 and 2016 excludes net pre-tax (losses) gains of $(2.9) million and $33.8 million, respectively, on AmeriGas Propane commodity derivative instruments not associated with current-period transactions.
(b) Partnership Adjusted EBITDA should not be considered as an alternative to net income (as an indicator of operating performance) and is not a measure of performance or financial condition under GAAP. Management uses Partnership Adjusted EBITDA as the primary measure of segment profitability for the AmeriGas Propane segment (see Note 14 to condensed consolidated financial statements).
(c) Amounts for the six months ended March 31, 2017 reflect adjustments to correct previously recorded gains on sales of fixed assets ($8.8 million) and decrease depreciation expense ($1.1 million) relating to certain assets acquired in the Heritage acquisition in 2012, which reduced Partnership Adjusted EBITDA by $8.8 million and reduced operating income by $7.7 million.
(d) Operating income reflects certain operating and administrative expenses of the General Partner.
(e) Deviation from average heating degree days for the 30-year period 1981-2010 based upon national weather statistics provided by NOAA for 344 Geo Regions in the United States, excluding Alaska and Hawaii.

AmeriGas Propane's retail gallons sold during the 2017 six-month period decreased 1.8% compared with the prior-year period. Average temperatures during the 2017 six-month period were 1.3% colder than the prior-year period but significantly warmer than normal. Although average temperatures during the 2017 six-month period were slightly colder than the prior year, the critical heating season months of January and February averaged more than 9% warmer than during the same period of the prior year.

AmeriGas Propane's retail propane revenues increased $60.3 million during the 2017 six-month period reflecting the effects of higher average retail selling prices ($84.4 million) partially offset by the lower retail volumes sold ($24.1 million). Wholesale propane revenues increased $6.4 million during the 2017 six-month period reflecting the effects of higher average wholesale selling prices ($7.4 million) partially offset by lower wholesale volumes sold ($1.0 million). Average daily wholesale propane commodity prices during the 2017 six-month period at Mont Belvieu, Texas, one of the major supply points in the U.S., were approximately 60% higher than such prices during the 2016 six-month period. Other revenues in the 2017 six-month period were slightly higher than in the prior-year period. AmeriGas Propane total cost of sales increased $75.1 million principally reflecting the effects of higher Partnership average propane product costs ($85.2 million) reduced by the effects of the lower propane volumes sold ($9.9 million).

AmeriGas Propane total margin decreased $5.9 million in the 2017 six-month period principally reflecting lower retail propane total margin ($8.1 million) partially offset by higher non-propane total margin. The decrease in retail propane total margin principally reflects the decrease in retail volumes sold partially offset by slightly higher average retail unit margin.

Partnership Adjusted EBITDA decreased $16.8 million in the 2017 six-month period principally reflecting the effects of the lower total margin ($5.9 million) and the impact of lower other operating income ($13.5 million) principally lower gains on asset sales including an $8.8 million adjustment recorded during the first quarter of Fiscal 2017 to correct previously recorded gains on sales of fixed assets acquired with the Heritage acquisition in 2012. Partnership operating and administrative expenses decreased reflecting, among other things, lower employee group insurance expenses ($8.5 million) partially offset by higher general insurance and self-insured casualty and liability expenses ($4.0 million) and higher vehicle expenses ($4.0 million). AmeriGas Propane operating income decreased $10.8 million in the 2017 six-month period principally reflecting the $16.8 million decrease in Partnership Adjusted EBITDA partially offset by a decrease in depreciation and amortization expense ($7.0 million), which includes the previously mentioned $1.1 million adjustment to depreciation relating to certain assets acquired in the Heritage acquisition in 2012.

During the 2017 six-month period, AmeriGas Partners recognized a pre-tax loss of $55.3 million associated with early repayments of $878.3 million principal amount of AmeriGas Partners' 7.00% Senior Notes comprising early redemption premiums and the write-off of unamortized debt issuance costs. Net income attributable to UGI reflects an after-tax loss of $8.9 million associated with this early extinguishment of debt (see Note 8 to condensed consolidated financial statements).

UGI International

For the six months ended March 31,	2017	2016	Increase (Decrease)	
(Dollars in millions)				
Revenues	$ 1,159.8	$ 1,156.9	$ 2.9	0.3 %
Total margin (a)	$ 588.7	$ 583.1	$ 5.6	1.0 %
Operating and administrative expenses (b)	$ 325.2	$ 326.0	$ (0.8)	(0.2)%
Operating income (b)	$ 209.9	$ 196.6	$ 13.3	6.8 %
Income before income taxes (b) (c)	$ 200.2	$ 183.5	$ 16.7	9.1 %
Retail gallons sold (millions) (d)	507.3	499.6	$ 7.7	1.5 %
UGI International degree days—% (warmer) than normal (e)	(3.4)%	(12.7)%	—	—

(a) Total margin represents total revenues less total cost of sales. Total margin for the six months ended March 31, 2017 and 2016 excludes net pre-tax (losses) gains of $(1.5) million and $18.9 million, respectively, on UGI International commodity derivative instruments not associated with current-period transactions.
(b) Reflects impacts of Finagaz integration expenses for the six months ended March 31, 2017 and 2016, of $14.8 million and $10.9 million, respectively.
(c) Income before income taxes for the six months ended March 31, 2017 excludes net pre-tax unrealized losses on certain foreign currency derivative contracts of $0.1 million.
(d) Excludes retail gallons from our LPG business in China, which was sold in March 2016.
(e) Deviation from average heating degree days primarily for the 30-year period 1981-2010 at locations in our UGI International service territories.

Average temperatures during the 2017 six-month period at UGI International were approximately 3.4% warmer than normal but 10.7% colder than the prior-year period. Total retail gallons sold during the 2017 six-month period were slightly higher than the prior-year period principally reflecting the effects of the colder weather offset in large part by a 53.1 million gallon decline in autogas volumes, principally the result of exiting the low-margin, high-volume autogas business in Poland, and lower crop-drying volumes the result of a dry crop season in France. During the 2017 six-month period, average wholesale commodity prices for propane and butane in northwest Europe were approximately 35% higher 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 2017 and 2016 six-month periods, the average un-weighted euro-to-dollar translation rates were approximately $1.07 and $1.09, respectively, and the average un-weighted British pound sterling-to-dollar translation rates were approximately $1.25 and $1.47, respectively. The effects of these weaker currencies did not negatively impact UGI International net income due to gains on foreign currency exchange contracts.

UGI International revenues increased $2.9 million during the 2017 six-month period principally reflecting higher LPG selling prices and the volume effects of the colder weather offset by the impact of exiting the low-margin autogas business in Poland and the translation impact on revenues of the weaker British pound sterling and the euro. UGI International cost of sales decreased $2.7 million during the 2017 six-month period principally reflecting lower cost of sales associated with exiting the autogas business in Poland and the translation impact on cost of sales from the weaker British pound sterling and, to a lesser extent, the euro, substantially offset by the impact of the higher average LPG commodity costs.

UGI International total margin increased $5.6 million primarily reflecting higher total margin from an increase in residential LPG bulk sales, principally a result of the colder weather and, to a much lesser extent, higher natural gas marketing total margin. These increases in total margin were partially offset by (1) the translation effects of the weaker British pound sterling and euro; (2) slightly lower average retail bulk and cylinder LPG unit margins; and (3) the absence of margin from the autogas business in Poland. The slightly lower average retail bulk and cylinder LPG unit margins principally reflect the effects on unit margins of rising LPG commodity costs during the 2017 six-month period compared with declining LPG commodity costs experienced during the prior-year period.

The $13.3 million increase in UGI International operating income principally reflects the previously mentioned $5.6 million increase in total margin, a $7.3 million increase in other operating income and a slight decrease in operating and administrative expenses. The increase in other operating income reflects, in part, the absence of a $5.5 million loss recorded during the prior-year period associated with interest rate hedge ineffectiveness. The slight decrease in operating and administrative expenses principally reflects the translation effects of the weaker euro and British pound sterling offset in large part by higher integration expenses associated with Finagaz and slightly higher base currency operating and administrative expenses. Operating and administrative expenses include $14.8 million and $10.9 million of Finagaz integration expenses in the 2017 and 2016 six-month periods, respectively. UGI International income before income taxes increased $16.7 million principally reflecting the previously mentioned $13.3 million increase in UGI International operating income and slightly lower interest expense principally due to a lower 2017 six-month period interest rate on UGI France SAS's €600 million Senior Facilities Agreement term loan.

Midstream & Marketing

For the six months ended March 31,	2017	2016	Increase	
(Dollars in millions)				
Revenues	$ 693.5	$ 525.7	$ 167.8	31.9%
Total margin (a)	$ 191.9	$ 181.5	$ 10.4	5.7%
Operating and administrative expenses	$ 47.0	$ 45.7	$ 1.3	2.8%
Operating income	$ 131.8	$ 120.7	$ 11.1	9.2%
Income before income taxes	$ 132.9	$ 119.4	$ 13.5	11.3%

(a) Total margin represents total revenues less total cost of sales. Total margin for the six months ended March 31, 2017 and 2016 excludes net pre-tax gains of $86.1 million and $12.4 million, respectively, on Midstream & Marketing commodity derivative instruments not associated with current period transactions.

Temperatures across Midstream & Marketing's energy marketing territory were 12.8% warmer than normal but 6.3% colder than in the prior-year period. Midstream & Marketing 2017 six-month period revenues were $167.8 million higher than in the 2016 six-month period principally reflecting higher natural gas revenues ($162.1 million) and, to a much lesser extent, higher peaking revenues ($12.5 million). The increase in natural gas revenues principally reflects higher natural gas volumes associated with the colder weather and customer growth, and higher average natural gas prices while the increase in peaking revenues reflects an increase in the number of contracts. These increases in revenues were partially offset principally by lower electric generation revenues ($4.3 million). Midstream & Marketing cost of sales was $501.6 million in the 2017 six-month period compared to $344.2 million in the 2016 six-month period, an increase of $157.4 million, principally reflecting higher natural gas cost of sales ($157.5 million), primarily a result of the higher natural gas volumes and prices.

Midstream & Marketing total margin increased $10.4 million in the 2017 six-month period principally reflecting higher peaking total margin ($11.9 million), higher natural gas total margin ($4.7 million) on higher sales and, to a much lesser extent, higher capacity management total margin ($3.8 million). The increase in peaking total margin reflects an increase in the number of contracts while the higher capacity management margin reflects slightly higher prices for pipeline capacity. These increases in total margin were partially offset primarily by lower electric generation total margin ($5.6 million), reflecting lower electricity generation volumes and lower capacity revenue, and a decrease in margin from storage services.

Midstream & Marketing operating income and income before income taxes during the 2017 six-month period increased $11.1 million and $13.5 million, respectively. The increase in operating income principally reflects the previously mentioned increase in total margin ($10.4 million) and higher other operating income ($2.8 million), principally AFUDC associated with pipeline capital expenditures, partially offset by slightly higher total operating, administrative and depreciation expenses. The $1.3 million increase in operating and administrative expenses reflects higher wage and benefits expense partially offset by lower Conemaugh and Hunlock electricity generating station operating and maintenance expenses, while the increase in depreciation principally reflects incremental depreciation from the expansion of our natural gas pipeline and peaking assets. The increase in income before income taxes in the 2017 six-month period reflects the higher operating income and also includes $2.4 million of income from our PennEast pipeline equity investment reflecting income from AFUDC.

UGI Utilities

For the six months ended March 31,	2017	2016	Increase (Decrease)	
(Dollars in millions)				
Revenues	$ 621.4	$ 520.0	$ 101.4	19.5%
Total margin (a)	$ 344.9	$ 304.7	$ 40.2	13.2%
Operating and administrative expenses	$ 106.2	$ 99.1	$ 7.1	7.2%
Operating income	$ 198.6	$ 162.8	$ 35.8	22.0%
Income before income taxes	$ 178.3	$ 144.0	$ 34.3	23.8%
Gas Utility system throughput—billions of cubic feet (“bcf”)				
Core market	56.7	51.4	5.3	10.3%
Total	148.0	122.0	26.0	21.3%
Electric Utility distribution sales - millions of kilowatt hours (“gwh”)	501.1	490.3	10.8	2.2%
Gas Utility heating degree days—% (warmer) than normal (b)	(10.0)%	(16.1)%	—	—

(a) Total margin represents total revenues less total cost of sales and revenue-related taxes, i.e., Electric Utility gross receipts taxes, of $2.5 million and $2.4 million during the six months ended March 31, 2017 and 2016, respectively. For financial statement purposes, revenue-related taxes are included in “utility taxes other than income taxes” on 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 six months ended March 31, 2017, were 10.0% warmer than normal but 6.9% colder than during the six months ended March 31, 2016. Gas Utility core market volumes increased 5.3 bcf (10.3%) principally reflecting the effects of the colder 2017 six-month period weather and, to a lesser extent, growth in the number of core market customers. Total Gas Utility distribution system throughput increased 26.0 bcf reflecting the higher core market volumes and significantly higher large firm delivery service volumes principally associated with service to a new natural gas-fired generation facility. Electric Utility kilowatt-hour sales were 2.2% higher than the prior-year period, principally reflecting the impact of the colder weather on Electric Utility heating-related sales.

UGI Utilities revenues increased $101.4 million reflecting a $98.0 million increase in Gas Utility revenues and higher Electric Utility revenues. The higher Gas Utility revenues principally reflect an increase in core market revenues ($72.4 million), higher large firm delivery service revenues ($10.9 million) and higher off-system sales revenues ($15.2 million). The $72.4 million increase in Gas Utility core market revenues reflects the effects of the higher core market throughput ($33.7 million), higher average retail core market PGC rates ($25.0 million), and the increase in UGI Gas base rates effective October 19, 2016 ($13.7 million). The increase in Electric Utility revenues principally reflects the higher Electric Utility volumes ($1.3 million) and slightly higher average DS rates ($1.7 million). UGI Utilities cost of sales was $274.0 million for the six months ended March 31, 2017 compared with $212.9 million for the six months ended March 31, 2016, an increase of $61.1 million, principally reflecting the higher Gas Utility retail core-market volumes ($16.4 million), higher average retail core market PGC rates ($25.0 million) and higher cost of sales associated with Gas Utility off-system sales ($15.2 million). In addition, the higher cost of sales reflects an increase in Electric Utility cost of sales of $2.6 million resulting from the higher volumes sold and the slightly higher DS rates.

UGI Utilities total margin increased $40.2 million principally reflecting higher total margin from Gas Utility core market customers ($31.0 million) and higher large firm delivery service total margin ($8.1 million). The increase in Gas Utility core market margin principally reflects the higher core market throughput ($17.3 million) due to the colder weather and the increase in UGI Gas base rates effective October 19, 2016 ($13.7 million). Electric Utility total margin increased slightly principally reflecting the higher volume sales as a result of the colder weather.

UGI Utilities operating income increased $35.8 million principally reflecting the increase in total margin ($40.2 million) and higher other operating income, net ($4.5 million) principally reflecting lower environmental matters expenses and lower interest on PGC overcollections. These increases were reduced by higher operating and administrative expenses ($7.1 million) and higher depreciation and amortization expense associated with increased capital expenditure activity ($1.4 million). Operating and administrative expenses in the prior-year six-month period were reduced by the capitalization of $5.4 million of development stage IT project expenditures that had been expensed in prior periods but qualified for capitalization during the 2016 six-month period. The increase in UGI Utilities operating and administrative expenses in the current year also reflects higher Electric Utility distribution system expenses. UGI Utilities income before income taxes increased $34.3 million reflecting the increase in UGI

Utilities operating income ($35.8 million), partially offset by slightly higher interest expense principally due to higher average long-term debt outstanding.

Interest Expense and Income Taxes

Our consolidated interest expense during the 2017 six-month period was $111.2 million, $4.0 million lower than the $115.2 million of interest expense recorded during the 2016 six-month period. The lower interest expense principally reflects lower average interest rates on long-term debt at UGI International and AmeriGas Propane, and lower credit agreement borrowings at AmeriGas Propane. These decreases were partially offset by the effects of higher long-term debt outstanding at AmeriGas Propane and UGI Utilities.

Our effective income tax rate as a percentage of pre-tax income (excluding the effects on such rate of pre-tax income associated with non-controlling interests not subject to federal income taxes) was 32.0% in the 2017 six-month period compared to 39.8% in the 2016 six-month period. The significant decrease in the effective income tax rate is due primarily to the impact of the change in the French corporate income tax rate on net deferred income tax liabilities, which reduced consolidated income tax expense during the 2017 six-month period by $27.4 million (see Note 2 to condensed consolidated financial statements); the effects of an income tax settlement refund of $6.7 million, plus interest, in France; the impact of $7.0 million of excess tax benefits on share based payments resulting from the adoption of new accounting guidance on share based payments effective October 1, 2016 (see Note 3 to condensed consolidated financial statements); and, to a lesser extent, the impact of a higher proportion of pre-tax earnings associated with our UGI International operations, which have a lower effective tax rate than our domestic U.S. operations.

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 Facility. Long-term cash requirements 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 Receivable 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 $637.8 million at March 31, 2017, compared with $502.8 million at September 30, 2016. Excluding cash and cash equivalents that reside at UGI’s operating subsidiaries, at March 31, 2017 and September 30, 2016, UGI had $215.3 million and $125.7 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.

Long-term Debt and Short-term Borrowings

Long-term Debt

The Company's debt outstanding at March 31, 2017 and September 30, 2016, comprises the following:

	March 31, 2017						September 30, 2016
(Currency in millions)	AmeriGas Propane	UGI International	Midstream & Marketing	UGI Utilities	Other	Total	Total
Short-term borrowings	$ —	$ 1.6	$ —	$ 48.5	$ —	$ 50.1	$ 291.7
Long-term debt (including current maturities):							
Senior notes	$ 2,677.5	$ —	$ —	$ 675.0	$ —	$ 3,352.5	$ 2,905.8
Term loans and notes	—	747.2	—	100.0	—	847.2	884.9
Other long-term debt	28.6	1.0	0.6	—	9.7	39.9	41.6
Unamortized debt issuance costs	(34.2)	(5.4)	—	(4.0)	—	(43.6)	(36.8)
Total long-term debt	$ 2,671.9	$ 742.8	$ 0.6	$ 771.0	$ 9.7	$ 4,196.0	$ 3,795.5
Total debt	$ 2,671.9	$ 744.4	$ 0.6	$ 819.5	$ 9.7	$ 4,246.1	$ 4,087.2

AmeriGas Partners. In December 2016, AmeriGas Partners issued $700.0 million principal amount of 5.50% Senior Notes due May 2025 (the "AmeriGas Partners' 5.50% Senior Notes"). The net proceeds from the issuance of the AmeriGas Partners' 5.50% Senior Notes were used in December 2016 for (1) the early repayment, pursuant to a tender offer, of a portion of AmeriGas Partners' 7.00% Senior Notes having an aggregate principal balance of $500.0 million plus accrued and unpaid interest and early redemption premiums; (2) the reduction of short-term borrowings; and (3) general corporate purposes.

In February 2017, AmeriGas Partners issued $525.0 million principal amount of 5.75% Senior Notes due May 2027 (the "AmeriGas Partners' 5.75% Senior Notes"). The net proceeds from the issuance of the AmeriGas Partners' 5.75% Senior Notes were used in February 2017 for (1) the early repayment, pursuant to a tender offer, of a portion of AmeriGas Partners' 7.00% Senior Notes having an aggregate principal balance of $378.3 million plus accrued and unpaid interest and early redemption premiums; (2) the repayment of short-term borrowings; and (3) general corporate purposes.

In March 2017, AmeriGas Partners issued a notice of early redemption for the remaining AmeriGas Partners' 7.00% Senior Notes not previously tendered, having an aggregate principal balance of $102.5 million, plus early redemption premiums and accrued and unpaid interest. These 7.00% Senior Notes have a redemption date of May 20, 2017. The Partnership expects to repay these 7.00% Senior Notes and redemption premiums from cash on hand and borrowings under its revolving credit agreement.

UGI Utilities. Pursuant to a Note Purchase Agreement, in October 2016, UGI Utilities issued $100.0 million aggregate principal amount of 4.12% Senior Notes due October 2046 (the "UGI Utilities' 4.12% Senior Notes"). The net proceeds of the issuance of the UGI Utilities' 4.12% Senior Notes were used (1) to provide additional financing for UGI Utilities' infrastructure replacement and betterment capital program and information technology initiatives; and (2) for general corporate purposes.

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 2016 Annual Report.

Information about the Company's principal credit agreements (excluding the Energy Services Receivables Facility discussed below) as of March 31, 2017 and 2016, is presented in the table below.

(Currency in millions)	Total Capacity		Borrowings Outstanding		Letters of Credit and Guarantees Outstanding		Available Capacity	
As of March 31, 2017								
AmeriGas OLP	$	525.0	$	—	$	67.2	$	457.8
UGI France SAS	€	60.0	€	—	€	—	€	60.0
Flaga GmbH (a)	€	55.0	€	—	€	7.4	€	47.6
UGI Utilities	$	300.0	$	48.5	$	2.0	$	249.5
Energy Services, LLC	$	240.0	$	—	$	—	$	240.0
As of March 31, 2016								
AmeriGas OLP	$	525.0	$	65.3	$	63.0	$	396.7
UGI France SAS	€	60.0	€	—	€	—	€	60.0
Flaga GmbH (a)	€	55.0	€	—	€	9.5	€	45.5
UGI Utilities	$	300.0	$	155.0	$	2.0	$	143.0
Energy Services, LLC	$	240.0	$	—	$	—	$	240.0

(a) Total capacity comprises a €25 million multi-currency revolving credit facility, a €5 million overdraft facility and a €25 million guarantee facility. Guarantees outstanding reduce the available capacity on the €25 million guarantee facility.

The average daily and peak short-term borrowings under the Company's principal credit agreements during the six months ended March 31, 2017 and 2016 are as follows:

	For the six months ended March 31, 2017				For the six months ended March 31, 2016			
(Currency in millions)	Average		Peak		Average		Peak	
AmeriGas OLP	$	105.0	$	292.5	$	131.5	$	249.0
UGI France SAS	€	—	€	—	€	—	€	—
Flaga GmbH	€	—	€	—	€	—	€	—
UGI Utilities	$	92.4	$	137.0	$	177.6	$	232.0
Energy Services, LLC	$	12.6	$	28.0	$	18.7	$	35.0

Energy Services, LLC also has a receivables purchase facility ("Receivables Facility") with an issuer of receivables-backed commercial paper currently scheduled to expire in October 2017. At March 31, 2017, the outstanding balance of ESFC trade receivables was $85.3 million and there were no amounts sold to the bank. At March 31, 2016, the outstanding balance of ESFC trade receivables was $55.3 million, of which $4.0 million was sold to the bank. Amounts sold to the bank are reflected as "short-term borrowings" on the Condensed Consolidated Balance Sheets. During the six months ended March 31, 2017 and 2016, peak sales of receivables were $49.0 million and $46.0 million, respectively, and average daily amounts sold were $15.7 million and $25.5 million, respectively. For additional information regarding the Receivables Facility, see Note 7 to the condensed consolidated financial statements.

Dividends and Distributions

On April 25, 2017, UGI's Board of Directors approved an increase in the quarterly dividend rate on UGI Common Stock to $0.25 per Common Share, or $1.00 on an annual basis. The new dividend rate reflects an approximately 5.3% increase from the previous quarterly rate of $0.2375. The new quarterly dividend rate is effective with the dividend payable on July 1, 2017, to shareholders of record on June 15, 2017.

On April 24, 2017, the General Partner's Board of Directors approved an increase in the quarterly distribution rate on AmeriGas Partners Common Units to $0.95 per Common Unit, equal to an annual rate of $3.80 per Common Unit. The distribution reflects a 1.1% increase from the previous quarterly rate of $0.94. The new quarterly rate is effective with the distribution payable on May 18, 2017, to unitholders of record on May 10, 2017.

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 $585.0 million in the 2017 six-month period compared to $618.3 million in the 2016 six-month period. Cash flow from operating activities before changes in operating working capital was $862.5 million in the 2017 six-month period compared to $777.3 million in the prior-year period. The higher cash flow from operating activities before changes in operating working capital reflects the positive effects on cash flow of higher net income (after adjusting net income for the non-cash effects of changes in unrealized gains on derivative instruments, and the loss on extinguishments of debt at AmeriGas Partners, the cash flow effects of which are reflected in cash flows from financing activities). Cash used to fund changes in operating working capital totaled $277.5 million in the 2017 six-month period compared to $159.0 million in the prior-year period. The significantly higher cash required to fund changes in accounts receivable partially offset by the higher cash provided from changes in accounts payable reflects, in large part, the impact of increasing LPG and natural gas costs during the current-year period and the effects on these working capital accounts of colder U.S. weather late in the 2017 six-month period.

Investing Activities. Cash flow used by investing activities was $338.1 million in the 2017 six-month period compared with $268.2 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 $341.8 million in the 2017 six-month period compared to $254.6 million in the prior-year period reflecting, in large part, higher pipeline and peaking asset-related cash capital expenditures at our Midstream & Marketing segment, and higher information technology capital expenditures at UGI Utilities. Cash used for acquisitions of businesses in the 2017 six-month period reflects net cash paid for two small propane acquisitions at AmeriGas Propane while the higher cash paid in the prior-year period reflects greater acquisition activity at AmeriGas Propane and UGI International acquisitions.

Financing Activities. Cash flow used by financing activities was $95.9 million in the 2017 six-month period compared with $259.6 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. In February 2017, AmeriGas Partners and AmeriGas Finance Corp. issued $525 million of 5.75% Senior Notes due May 2027. The net proceeds from the issuance of the 5.75% Senior Notes were used for (1) the early repayment of $378.3 million principal amount of AmeriGas Partners' 7.00% Senior Notes including accrued and unpaid interest and early redemption premiums; (2) the repayment of short-term borrowings; and (3) for general corporate purposes. In December 2016, AmeriGas Partners issued $700 million principal amount of AmeriGas Partners 5.50% Senior Notes and used the net proceeds to repay $500 million principal amount of existing AmeriGas Partners 7.00% Senior Notes subject to a tender offer and to reduce short-term borrowings. In addition, in October 2016, UGI Utilities issued $100 million of 4.12% Senior Notes and used the net proceeds principally to reduce short-term borrowings and for general corporate purposes. See Note 8 to condensed consolidated financial statements for additional information on these debt transactions.

The effect of exchange rate changes on cash during the six months ended March 31, 2017, reflects the effects on foreign subsidiary cash balances of a weaker euro and British pound sterling.

UTILITY REGULATORY MATTERS

Base Rate Filings. On January 19, 2017, PNG filed a rate request with the PUC to increase PNG's base operating revenues for residential, commercial and industrial customers by $21.7 million annually. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. PNG requested that the new gas rates become effective March 20, 2017. The PUC entered an Order dated February 9, 2017, suspending the effective date for the rate increase to allow for investigation and public hearings. Unless a settlement is reached sooner, this review process is expected to last up to nine months from the date of filing; however, the Company cannot predict the timing or the ultimate outcome of the rate case review process.

On October 14, 2016, the PUC approved a previously filed Joint Petition for Approval of Settlement of all issues providing for a $27.0 million annual base distribution rate increase for UGI Gas. The increase became effective on October 19, 2016.

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 5% of distribution charges billed to customers.

PNG and CPG received PUC approval on a DSIC tariff, initially set at zero, in 2014. 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 5% to 10% of billed distribution revenues. On April 20, 2017, the PUC voted to approve an increase of the maximum allowable DSIC to 7.5% of billed distribution revenues effective July 1, 2017 for PNG and CPG, pending the issuance of a final order of the PUC.

On November 9, 2016, UGI Gas received PUC approval to establish a DSIC tariff mechanism effective January 1, 2017. Revenue collected pursuant to the mechanism will be subject to refund and recoupment based on the PUC's final resolution of certain matters set aside for hearing before an administrative law judge. UGI Gas will be permitted to recover revenue under the mechanism for the amount of DSIC-eligible plant placed into service in excess of the threshold amount of DSIC-eligible plant agreed upon in the settlement of its recent base rate case. Achievement of that threshold is not likely to occur prior to September 30, 2017.

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, certain of our UGI International businesses 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 March 31, 2017, the fair values of Gas Utility’s natural gas futures and option contracts were net gains of $2.0 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 March 31, 2017, all of our Electric Utility’s forward electricity purchase contracts were subject to the NPNS exception. At March 31, 2017, 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 contracts are recorded at fair value with changes in fair value reflected in “Operating and administrative expenses” on the Condensed Consolidated Statements of Income.

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

From time to time, 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.

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 March 31, 2017 (excluding those Gas Utility and Electric Utility commodity derivative instruments that are refundable to, or recoverable from, customers) was a gain of $33.1 million. A hypothetical 10% adverse change in the market price of LPG, gasoline, natural gas, electricity and electricity transmission congestion charges would decrease such gain by approximately $39.7 million at March 31, 2017.

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 March 31, 2017, includes short-term borrowings and UGI France SAS's and Flaga GmbH's variable-rate term loans. These debt agreements have interest rates that are generally indexed to short-term market interest rates. UGI France SAS and Flaga GmbH, 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 GmbH's U.S. dollar-denominated loan has been swapped from a floating U.S. dollar-denominated interest rate to a fixed euro-denominated interest rate through a cross-currency swap, removing interest rate risk (and foreign currency exchange risk as further described below under Foreign Currency Exchange Rate Risk) associated with the underlying interest payments. At March 31, 2017, combined borrowings outstanding under variable-rate debt agreements, excluding UGI France SAS's and Flaga GmbH's effectively fixed-rate debt, totaled $50.1 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 March 31, 2017 (including pay-fixed, receive-variable interest rate swaps) was a loss of $2.2 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 $2.0 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 sold or liquidated. At March 31, 2017, 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 March 31, 2017 by approximately $110.0 million, which amount would be reflected in other comprehensive income.

In addition, in order to reduce exposure to foreign exchange rate volatility related to our foreign LPG operations, through September 30, 2016, we entered into forward foreign currency exchange contracts to hedge a portion of anticipated U.S. dollar-denominated LPG product purchases primarily during the heating-season months of October through March.

Beginning October 1, 2016, in order to reduce the volatility in net income associated with our foreign operations principally as a result of changes in the U.S. dollar exchange rate between the euro and British pound sterling, we enter into forward foreign currency exchange contracts.

As previously mentioned, Flaga GmbH has a cross-currency swap 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. This 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 fair value of unsettled foreign currency exchange rate risk sensitive derivative instruments held at March 31, 2017, including the fair value of Flaga GmbH's cross-currency swap, was a gain of $17.1 million. A hypothetical 10% adverse change in the value of the euro and the British pound sterling versus the U.S. dollar would result in a decrease in fair value of approximately $36.3 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 March 31, 2017, restricted cash in brokerage accounts totaled $0.3 million. 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 March 31, 2017. 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 March 31, 2017, 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, 2016, 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 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information with respect to the Company’s repurchases of its common stock during the quarter ended March 31, 2017.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
January 1, 2017 to January 31, 2017	300,000	$46.14	300,000	11.22 million
February 1, 2017 to February 28, 2017	—	—	—	11.22 million
March 1, 2017 to March 31, 2017	235,000	$49.41	235,000	10.98 million
Total	535,000		535,000	

(1) Shares of UGI Corporation Common Stock are repurchased through a share repurchase program announced by the Company on January 30, 2014. The Board of Directors authorized the repurchase of up to 15 million shares of UGI Corporation Common Stock over a four-year period.

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**
10.1	Amendment to Contingent Residual Support Agreement dated February 6, 2017, 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 (2/6/17)	10.1
31.1	Certification by the Chief Executive Officer relating to the Registrant's Report on Form 10-Q for the quarter ended March 31, 2017, 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 March 31, 2017, 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 March 31, 2017, 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: May 5, 2017	By: /s/ Kirk R. Oliver Kirk R. Oliver Chief Financial Officer
Date: May 5, 2017	By: /s/ Marie-Dominique Ortiz-Landazabal Marie-Dominique Ortiz-Landazabal Vice President - Accounting and Financial Control and Chief Accounting Officer

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 March 31, 2017, 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 March 31, 2017, 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 March 31, 2017, 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: May 5, 2017

/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: May 5, 2017

/s/ Kirk R. Oliver

Kirk R. Oliver

Chief Financial Officer of UGI Corporation

EXHIBIT 32

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 March 31, 2017 (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: May 5, 2017	Date: May 5, 2017