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

o **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 1-1398

UGI UTILITIES, INC.

(Exact name of registrant as specified in its charter)

Pennsylvania	23-1174060
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2525 N. 12th Street, Suite 360, Reading, PA 19612
(Address of principal executive offices) (Zip Code)

(610) 796-3400
(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 o

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 o

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	o	Accelerated filer	o	Non-accelerated filer	☑
Smaller reporting company	o	Emerging growth company	o		

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 o No ☑

At April 30, 2017, there were 26,781,785 shares of UGI Utilities, Inc. Common Stock, par value $2.25 per share, outstanding, all of which were held, beneficially and of record, by UGI Corporation.

UGI UTILITIES, INC. AND SUBSIDIARIES

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UGI UTILITIES, INC. AND SUBSIDIARIES

PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	March 31, 2017	September 30, 2016	March 31, 2016
ASSETS			
Current assets:			
Cash and cash equivalents	$ 4,566	$ 2,819	$ 26,406
Restricted cash	347	583	3,909
Accounts receivable (less allowances for doubtful accounts of $9,401, $3,946 and $8,232, respectively)	123,285	44,692	102,125
Accounts receivable — related parties	1,739	398	1,271
Accrued utility revenues	36,665	12,753	24,052
Inventories	17,174	42,340	16,685
Prepaid income taxes	301	1,956	—
Regulatory assets	2,309	3,208	3,229
Derivative instruments	2,024	4,263	881
Prepaid expenses & other current assets	22,957	22,009	27,632
Total current assets	211,367	135,021	206,190
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $997,591, $975,374 and $952,478, respectively)	2,112,013	2,023,541	1,900,806
Goodwill	182,145	182,145	182,145
Regulatory assets	392,408	391,933	344,983
Other assets	11,792	10,451	5,395
Total assets	$ 2,909,725	$ 2,743,091	$ 2,639,519
LIABILITIES AND STOCKHOLDER’S EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 59,980	$ 19,986	$ —
Short-term borrowings	48,500	112,500	155,000
Accounts payable	58,095	65,180	42,681
Accounts payable — related parties	11,339	3,995	6,710
Regulatory liability — deferred fuel and power refunds	13,791	22,299	30,838
Derivative instruments	19	310	3,370
Other current liabilities	126,342	109,640	152,479
Total current liabilities	318,066	333,910	391,078
Long-term debt	711,066	651,455	547,932
Deferred income taxes	590,964	550,229	526,937
Deferred investment tax credits	3,109	3,268	3,429
Pension and postretirement benefit obligations	179,101	184,516	130,915
Other noncurrent liabilities	96,838	94,976	99,029
Total liabilities	1,899,144	1,818,354	1,699,320
Commitments and contingencies (Note 7)			
Common stockholder’s equity:			
Common Stock, $2.25 par value (authorized — 40,000,000 shares; issued and outstanding — 26,781,785 shares)	60,259	60,259	60,259
Additional paid-in capital	473,580	473,580	472,715
Retained earnings	506,906	422,516	436,788
Accumulated other comprehensive loss	(30,164)	(31,618)	(29,563)
Total common stockholder’s equity	1,010,581	924,737	940,199
Total liabilities and stockholder’s equity	$ 2,909,725	$ 2,743,091	$ 2,639,519

See accompanying notes to condensed consolidated financial statements.

UGI UTILITIES, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)
(Thousands of dollars)

	Three Months Ended March 31,		Six Months Ended March 31,	
	2017	2016	2017	2016
Revenues	$ 359,940	$ 322,047	$ 621,353	$ 520,029
Costs and expenses:				
Cost of sales — gas, fuel and purchased power (excluding depreciation shown below)	164,541	137,434	274,012	212,873
Operating and administrative expenses	53,064	45,125	99,101	93,152
Operating and administrative expenses — related parties	4,534	3,798	7,098	5,978
Taxes other than income taxes	4,957	4,448	8,636	8,217
Depreciation	17,125	16,146	33,987	31,973
Amortization	574	884	1,103	1,758
Other operating (income) expense, net	(1,263)	(269)	(1,228)	3,301
	243,532	207,566	422,709	357,252
Operating income	116,408	114,481	198,644	162,777
Interest expense	10,322	9,270	20,350	18,764
Income before income taxes	106,086	105,211	178,294	144,013
Income taxes	40,961	41,917	68,904	57,368
Net income	$ 65,125	$ 63,294	$ 109,390	$ 86,645

See accompanying notes to condensed consolidated financial statements.

UGI UTILITIES, INC. AND SUBSIDIARIES

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

	Three Months Ended March 31,		Six Months Ended March 31,	
	2017	2016	2017	2016
Net income	$ 65,125	$ 63,294	$ 109,390	$ 86,645
Other comprehensive income (loss):				
Net losses on derivative instruments (net of tax of $0, $13,348, $0, and $12,016, respectively)	—	(18,820)	—	(16,943)
Reclassifications of net losses on derivative instruments (net of tax of $(341), $(253), $(692), and $(529), respectively)	481	356	976	746
Benefit plans reclassifications of actuarial losses and prior service costs (net of tax of $(169), $(114), $(338), and $(227), respectively)	239	160	478	320
Other comprehensive income (loss)	720	(18,304)	1,454	(15,877)
Comprehensive income	$ 65,845	$ 44,990	$ 110,844	$ 70,768

See accompanying notes to condensed consolidated financial statements.

UGI UTILITIES, INC. AND SUBSIDIARIES

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

	Six Months Ended March 31, 2017	Six Months Ended March 31, 2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 109,390	$ 86,645
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	35,090	33,731
Deferred income tax expense	35,992	48,905
Provision for uncollectible accounts	6,265	5,572
Other, net	6,292	2,138
Net change in:		
Accounts receivable and accrued utility revenues	(110,111)	(66,130)
Inventories	25,166	35,031
Deferred fuel and power costs, net of changes in unsettled derivatives	(7,601)	(7,789)
Accounts payable	14,722	(3,882)
Other current assets	(948)	(2,529)
Other current liabilities	17,591	20,691
Net cash provided by operating activities	131,848	152,383
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(135,075)	(116,778)
Net costs of property, plant and equipment disposals	(5,753)	(5,101)
Decrease in restricted cash	236	2,693
Net cash used by investing activities	(140,592)	(119,186)
CASH FLOWS FROM FINANCING ACTIVITIES		
Payments of dividends	(25,000)	(22,000)
Issuances of long-term debt, net of issuance costs	99,491	—
Repayments of long-term debt	—	(72,000)
(Decrease) increase in short-term borrowings	(64,000)	83,300
Other	—	810
Net cash provided (used) by financing activities	10,491	(9,890)
Cash and cash equivalents increase	$ 1,747	$ 23,307
CASH AND CASH EQUIVALENTS		
End of period	$ 4,566	$ 26,406
Beginning of period	2,819	3,099
Increase	$ 1,747	$ 23,307

See accompanying notes to condensed consolidated financial statements.

UGI UTILITIES, INC. AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

Note 1 — Nature of Operations

UGI Utilities, Inc. ("UGI Utilities"), a wholly owned subsidiary of UGI Corporation ("UGI"), and UGI Utilities' wholly owned subsidiaries UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc. ("CPG"), own and operate natural gas distribution utilities in eastern, northeastern and central Pennsylvania and in a portion of one Maryland county. UGI Utilities also owns and operates an electric distribution utility in northeastern Pennsylvania ("Electric Utility"). UGI Utilities' natural gas distribution utility is referred to as "UGI Gas." UGI Gas, PNG and CPG are collectively referred to as "Gas Utility." Gas Utility is subject to regulation by the Pennsylvania Public Utility Commission ("PUC") and, with respect to a small service territory in one Maryland county, the Maryland Public Service Commission, and Electric Utility is subject to regulation by the PUC. Gas Utility and Electric Utility are collectively referred to as "Utilities."

The term "UGI Utilities" is used sometimes as an abbreviated reference to UGI Utilities, Inc., or to UGI Utilities, Inc. and its subsidiaries, including PNG and CPG.

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation. Our condensed consolidated financial statements include the accounts of UGI Utilities and its subsidiaries (collectively, "we" or the "Company"). We eliminate intercompany accounts when we consolidate.

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 do not include all disclosures required by accounting principles generally accepted in the United States of America ("GAAP").

These financial statements should be read in conjunction with the financial statements and related notes included in our Annual Report on Form 10-K for the fiscal year ended September 30, 2016 ("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.

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 and such exception has been elected. The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is subject to regulatory ratemaking mechanisms or is designated and qualifies for hedge accounting.

Gains and losses on substantially all of the derivative instruments used by UGI Utilities (for which NPNS has not been elected) to hedge commodity prices are included in regulatory assets and liabilities in accordance with GAAP regarding accounting for rate-regulated entities. Certain of our derivative instruments are designated and qualify as cash flow hedges. For cash flow hedges, changes in the fair value of the derivative financial instruments are recorded in accumulated other comprehensive income (loss) ("AOCI"), to the extent effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. We discontinue cash flow hedge accounting if the 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. Certain other commodity derivative financial instruments, although generally effective as hedges, do not qualify for hedge accounting treatment. Changes in the fair values of these derivative instruments are reflected in net income. Cash flows from derivative financial instruments are included in cash flows from operating 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 10.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

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 new accounting guidance adopted, the Company has reflected $2,068 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."

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.

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

Note 3 — Accounting Changes

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. The adoption of the new accounting guidance did not have a material impact on our 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.

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
Gas Utility natural gas	$ 2,394	$ 29,223	$ 3,786
Materials, supplies and other	14,780	13,117	12,899
Total inventories	$ 17,174	$ 42,340	$ 16,685

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. Four of the SCAAs were with UGI Energy Services, LLC ("Energy Services"), a second-tier, wholly owned subsidiary of UGI (see Note 12) and one of the SCAAs is with a non-affiliate. 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.

The carrying values of gas storage inventories released under the SCAAs at March 31, 2017, September 30, 2016 and March 31, 2016, comprising 0.8 billion cubic feet ("bcf"), 8.1 bcf and 1.1 bcf of natural gas, were $1,964, $18,773 and $2,593, respectively. At March 31, 2017, September 30, 2016 and March 31, 2016, UGI Utilities held a total of $15,040, $19,100 and $15,100, respectively, of security deposits received from its SCAA counterparties. These amounts are included in "Other current liabilities" on the Condensed Consolidated Balance Sheets.

For additional information related to the SCAAs with Energy Services, see Note 12.

Note 5 — 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 4 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	$ 120,255	$ 115,643	$ 118,160
Underfunded pension and postretirement plans	175,598	183,129	135,825
Environmental costs	62,209	59,397	60,494
Deferred fuel and power costs	1,262	151	—
Removal costs, net	28,840	27,956	25,030
Other	6,553	8,865	8,703
Total regulatory assets	$ 394,717	$ 395,141	$ 348,212
Regulatory liabilities:			
Postretirement benefits	$ 16,974	$ 17,519	$ 19,307
Deferred fuel and power refunds	13,791	22,299	30,838
State tax benefits — distribution system repairs	16,145	15,086	14,158
Other	3,548	665	2,500
Total regulatory liabilities (a)	$ 50,458	$ 55,569	$ 66,803

(a) Regulatory liabilities, other than deferred fuel and power refunds, 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 $1,973, $4,263 and $(1,900), 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 10).

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 $21,700 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 $27,000 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 6 — Debt

Pursuant to a Note Purchase Agreement, in October 2016, UGI Utilities issued $100,000 aggregate principal amount of 4.12% Senior Notes due October 2046 (the "4.12% Senior Notes"). The net proceeds of the issuance of the 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 4.12% Senior Notes are unsecured and rank equally with UGI Utilities' existing outstanding senior debt.

Note 7 — Commitments and Contingencies

Contingencies

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 $2,500, $1,800, and $1,100, 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 effective at the end of any two-year period beginning with the original effective date of such 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 $55,659, $55,063, and $55,533, 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 5).

UGI Utilities does not expect the costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to its 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.

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

Note 8 — Defined Benefit Pension and Other Postretirement Plans

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 ("Pension Plan"). Pension Plan benefits are based on years of service, age and employee compensation. We also provide postretirement health care benefits to certain retirees and postretirement life insurance benefits to nearly all active and retired employees.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

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	$ 2,022	$ 1,732	$ 61	$ 45
Interest cost	5,539	5,818	107	117
Expected return on assets	(7,496)	(7,168)	(164)	(149)
Amortization of:				
Prior service cost (benefit)	82	87	(160)	(160)
Actuarial loss	3,706	2,393	29	25
Net benefit cost (income)	3,853	2,862	(127)	(122)
Change in associated regulatory liabilities	—	—	(123)	876
Net benefit cost (income) after change in regulatory liabilities	$ 3,853	$ 2,862	$ (250)	$ 754

	Pension Benefits		Other Postretirement Benefits	
Six Months Ended March 31,	2017	2016	2017	2016
Service cost	$ 4,045	$ 3,464	$ 122	$ 91
Interest cost	11,078	11,635	215	233
Expected return on assets	(14,993)	(14,335)	(328)	(298)
Amortization of:				
Prior service cost (benefit)	163	174	(320)	(320)
Actuarial loss	7,413	4,786	57	49
Net benefit cost (income)	7,706	5,724	(254)	(245)
Change in associated regulatory liabilities	—	—	(245)	1,754
Net benefit cost (income) after change in regulatory liabilities	$ 7,706	$ 5,724	$ (499)	$ 1,509

Pension Plan 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 Corporation Common Stock. It is our general policy to fund amounts for Pension Plan benefits equal to at least the minimum contribution required by ERISA. From time to time we may, at our discretion, contribute additional amounts. During the six months ended March 31, 2017 and 2016, the Company made contributions to the Pension Plan of $5,698 and $4,934, respectively. The Company expects to make additional discretionary cash contributions of approximately $5,500 to the 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 the 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 participate in an unfunded and non-qualified defined benefit supplemental executive retirement plan. Net benefit costs associated with this plan for all periods presented were not material.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

Note 9 — Fair Value Measurements

Derivative Instruments

The following table presents on a gross basis our derivative 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:				
Assets:				
Commodity contracts	$ 2,157	$ —	$ —	$ 2,157
Liabilities:				
Commodity contracts	$ (133)	$ (19)	$ —	$ (152)
September 30, 2016:				
Assets:				
Commodity contracts	$ 4,506	$ 4	$ —	$ 4,510
Liabilities:				
Commodity contracts	$ (263)	$ (294)	$ —	$ (557)
March 31, 2016:				
Assets:				
Commodity contracts	$ 1,179	$ —	$ —	$ 1,179
Liabilities:				
Commodity contracts	$ (3,281)	$ (387)	$ —	$ (3,668)

The fair values of our Level 1 exchange-traded commodity futures and option derivative contracts are based upon actively-quoted market prices for identical assets and liabilities. The fair values of the remainder of our derivative financial instruments and electricity forward contracts, which are designated as Level 2, are generally based upon recent market transactions and related market indicators. 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	$ 775,000	$ 675,000	$ 550,000
Estimated fair value	$ 801,675	$ 770,781	$ 637,016

Note 10 — 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 and (2) interest 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. Because most of our commodity derivative instruments are generally subject to regulatory ratemaking mechanisms, we have limited commodity price risk associated with our Gas Utility or Electric Utility operations.

Commodity Price Risk

Gas Utility's tariffs contain clauses that permit recovery of all of the prudently incurred costs of natural gas it sells to retail core-market customers, including the cost of financial instruments used to hedge purchased gas costs. As permitted and agreed to by the PUC pursuant to Gas Utility's annual PGC filings, Gas Utility currently uses New York Mercantile Exchange ("NYMEX") natural gas futures and option contracts to reduce commodity price volatility associated with a portion of the natural gas it purchases for its retail core-market customers. At March 31, 2017, September 30, 2016 and March 31, 2016, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 9.0 million dekatherms, 18.4 million dekatherms and 10.0 million dekatherms, respectively. At March 31, 2017, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 12 months. Gains and losses on 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 5).

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 5). At March 31, 2017, September 30, 2016 and March 31, 2016, the total volumes associated with FTRs totaled 14.6 million kilowatt hours, 58.3 million kilowatt hours and 69.2 million kilowatt hours, respectively. At March 31, 2017, the maximum period over which we are economically hedging electricity congestion is 2 months.

In order to reduce operating expense volatility, UGI Utilities from time to time enters into NYMEX gasoline futures contracts for a portion of gasoline volumes expected to be used in the operation of its vehicles and equipment. At March 31, 2017, September 30, 2016 and March 31, 2016, the total volumes associated with gasoline futures contracts were not material.

Interest Rate Risk

Our long-term debt typically is 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 IRPAs as cash flow hedges. As of March 31, 2017, September 30, 2016 and March 31, 2016, we had no unsettled IRPAs. At March 31, 2017, the amount of net losses associated with IRPAs expected to be reclassified into earnings during the next twelve months is $3,470.

Derivative Instrument Credit Risk

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 $347, $583 and $3,909, respectively.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities 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

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

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.

Fair Value of Derivative Instruments

The following table presents the Company's derivative assets and liabilities, as well as the effects of offsetting, as of March 31, 2017, September 30, 2016 and March 31, 2016:

	March 31, 2017	September 30, 2016	March 31, 2016
Derivative assets:			
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	$ 2,104	$ 4,472	$ 1,179
Derivatives not subject to PGC and DS mechanisms:			
Commodity contracts	53	38	—
Total derivative assets — gross	2,157	4,510	1,179
Gross amounts offset in the balance sheet	(133)	(247)	(298)
Total derivative assets — net	$ 2,024	$ 4,263	$ 881
Derivative liabilities:			
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	$ (150)	$ (499)	$ (3,466)
Derivatives not subject to PGC and DS mechanisms:			
Commodity contracts	(2)	(58)	(202)
Total derivative liabilities — gross	(152)	(557)	(3,668)
Gross amounts offset in the balance sheet	133	247	298
Total derivative liabilities — net	$ (19)	$ (310)	$ (3,370)

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

Effect of Derivative Instruments

The following table provides information on the effects of derivative instruments not subject to ratemaking mechanisms on the Condensed Consolidated Statements of Income and changes in AOCI for the three and six months ended March 31, 2017 and 2016:

	Loss Recognized in AOCI		Loss Reclassified from AOCI into Income		Location of Loss Reclassified from AOCI into Income
Three Months Ended March 31,	2017	2016	2017	2016	
Cash Flow Hedges:					
Interest rate contracts	$ —	$ (32,168)	$ (822)	$ (609)	Interest expense

	Loss Recognized in Income		Location of Loss Recognized in Income
Three Months Ended March 31,	2017	2016	
Derivatives Not Subject to PGC and DS Mechanisms:			
Gasoline contracts	$ (98)	$ (55)	Operating and administrative expenses

	Loss Recognized in AOCI		Loss Reclassified from AOCI into Income		Location of Loss Reclassified from AOCI into Income
Six Months Ended March 31,	2017	2016	2017	2016	
Cash Flow Hedges:					
Interest rate contracts	$ —	$ (28,959)	$ (1,668)	$ (1,275)	Interest expense

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Six Months Ended March 31,	2017	2016	
Derivatives Not Subject to PGC and DS Mechanisms:			
Gasoline contracts	$ 32	$ (120)	Operating and administrative expenses

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 which provide for the purchase and delivery of natural gas and electricity, and service contracts that require the counterparty to provide commodity storage, transportation or capacity service to meet our normal sales commitments. Although many of these contracts have the requisite elements of a derivative instrument, these contracts qualify for 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.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

Note 11 — Accumulated Other Comprehensive Income

The tables below present changes in AOCI, net of tax, during the three and six months ended March 31, 2017 and 2016:

Three Months Ended March 31, 2017	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — December 31, 2016	$ (11,595)	$ (19,289)	$ (30,884)
Reclassifications of benefit plan actuarial losses and prior service costs	239	—	239
Reclassifications of net losses on IRPAs	—	481	481
AOCI — March 31, 2017	$ (11,356)	$ (18,808)	$ (30,164)

Three Months Ended March 31, 2016	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — December 31, 2015	$ (9,116)	$ (2,143)	$ (11,259)
Net losses on IRPAs	—	(18,820)	(18,820)
Reclassifications of benefit plan actuarial losses and prior service costs	160	—	160
Reclassifications of net losses on IRPAs	—	356	356
AOCI — March 31, 2016	$ (8,956)	$ (20,607)	$ (29,563)

Six Months Ended March 31, 2017	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — September 30, 2016	$ (11,834)	$ (19,784)	$ (31,618)
Reclassifications of benefit plans actuarial losses and prior service costs	478	—	478
Reclassifications of net losses on IRPAs	—	976	976
AOCI — March 31, 2017	$ (11,356)	$ (18,808)	$ (30,164)

Six Months Ended March 31, 2016	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — September 30, 2015	$ (9,276)	$ (4,410)	$ (13,686)
Net losses on IRPAs	—	(16,943)	(16,943)
Reclassifications of benefit plans actuarial losses and prior service costs	320	—	320
Reclassifications of net losses on IRPAs	—	746	746
AOCI — March 31, 2016	$ (8,956)	$ (20,607)	$ (29,563)

Note 12 — Related Party Transactions

UGI provides certain financial and administrative services to UGI Utilities. UGI bills UGI Utilities monthly for all direct expenses incurred by UGI on behalf of UGI Utilities and an allocated share of indirect corporate expenses incurred or paid with respect to services provided to UGI Utilities. The allocation of indirect UGI corporate expenses to UGI Utilities utilizes a weighted, three-component formula comprising revenues, operating expenses and net assets employed and considers UGI Utilities' relative percentage of such items to the total of such items for all UGI operating subsidiaries for which general and administrative services are provided. Management believes that this allocation method is reasonable and equitable to UGI Utilities and this allocation method has been accepted by the PUC in past rate case proceedings and management audits as a reasonable method of allocating such expenses. These billed expenses are classified as "Operating and administrative expenses — related parties" on the Condensed Consolidated Statements of Income. In addition, UGI Utilities provides limited administrative services to UGI and certain of UGI's subsidiaries under PUC affiliated interest agreements. Amounts billed to these entities by UGI Utilities for all periods presented were not material.

From time to time, UGI Utilities is a party to SCAAs with Energy Services which have terms of up to three years. Under the SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts (subject to recall for operational purposes) to Energy Services for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon the commencement of the SCAAs, receives a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the term of the SCAAs. UGI Utilities incurred costs associated with Energy Services' SCAAs totaling $201 and $2,495 during the three and six months ended March 31, 2017, respectively, and $159 and $2,029 during the three and six months ended March 31, 2016, respectively. Energy Services, in turn, provides a firm delivery service and makes certain payments to UGI Utilities for its various obligations under the SCAAs. During the three and six months ended March 31, 2017 and 2016, these payments were not material. In conjunction with the SCAAs, UGI Utilities received security deposits from Energy Services. The amounts of such security deposits, which are included in "Other current liabilities" on the Condensed Consolidated Balance Sheets, were $11,040 at March 31, 2017 and $8,100 as of September 30, 2016 and March 31, 2016.

UGI Utilities reflects the historical cost of the gas storage inventories and any exchange receivable from Energy Services (representing amounts of natural gas inventories used but not yet replenished by Energy Services) in "Inventories" on the Condensed Consolidated Balance Sheets. The carrying values of these gas storage inventories at March 31, 2017, September 30, 2016 and March 31, 2016, comprising approximately 0.8 bcf, 4.6 bcf and 0.9 bcf of natural gas, were $1,964, $11,148 and $2,074, respectively.

UGI Utilities has gas supply and delivery service agreements with Energy Services pursuant to which Energy Services provides certain gas supply and related delivery service to Gas Utility primarily during the heating season months of November through March. The aggregate amount of these transactions (exclusive of transactions pursuant to the SCAAs) during the three and six months ended March 31, 2017 totaled $41,225 and $71,735, respectively. During the three and six months ended March 31, 2016, such purchases totaled $31,691 and $59,055, respectively.

From time to time, UGI Utilities sells natural gas or pipeline capacity to Energy Services. During the three and six months ended March 31, 2017, revenues associated with such sales to Energy Services totaled $22,310 and $33,282, respectively. During the three and six months ended March 31, 2016, revenues associated with such sales to Energy Services totaled $12,854 and $21,620, respectively. Also from time to time, UGI Utilities purchases natural gas, pipeline capacity and electricity from Energy Services (in addition to those transactions already described above) and purchases a firm storage service from UGI Storage Company, a subsidiary of Energy Services, under one-year agreements. During the three and six months ended March 31, 2017, such purchases totaled $39,085 and $61,108, respectively. During the three and six months ended March 31, 2016, such purchases totaled $14,912 and $23,104, respectively.

Note 13 — Segment Information

We have determined that we have two reportable segments: (1) Gas Utility and (2) Electric Utility. Gas Utility revenues are derived principally from the sale and distribution of natural gas to customers in eastern, northeastern and central Pennsylvania. Electric Utility derives its revenues principally from the sale and distribution of electricity in two northeastern Pennsylvania counties.

The accounting policies of our reportable segments are the same as those described in Note 2 of the Company's 2016 Annual Report. We evaluate the performance of our Gas Utility and Electric Utility segments principally based upon their income before income taxes.

UGI UTILITIES, INC. AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars)

Financial information by business segment follows:

			Reportable Segments	
Three Months Ended March 31, 2017		Total	Gas Utility	Electric Utility
Revenues		$ 359,940	$ 335,864	$ 24,076
Cost of sales — gas, fuel and purchased power		$ 164,541	$ 150,863	$ 13,678
Depreciation and amortization		$ 17,699	$ 16,378	$ 1,321
Operating income		$ 116,408	$ 115,105	$ 1,303
Interest expense		$ 10,322	$ 9,833	$ 489
Income before income taxes		$ 106,086	$ 105,272	$ 814
Capital expenditures (including the effects of accruals)		$ 56,517	$ 54,137	$ 2,380

		Reportable Segments	
Three Months Ended March 31, 2016	Total	Gas Utility	Electric Utility
Revenues	$ 322,047	$ 298,088	$ 23,959
Cost of sales — gas, fuel and purchased power	$ 137,434	$ 123,702	$ 13,732
Depreciation and amortization	$ 17,030	$ 15,822	$ 1,208
Operating income	$ 114,481	$ 111,004	$ 3,477
Interest expense	$ 9,270	$ 8,847	$ 423
Income before income taxes	$ 105,211	$ 102,157	$ 3,054
Capital expenditures (including the effects of accruals)	$ 48,113	$ 46,003	$ 2,110

		Reportable Segments	
Six Months Ended March 31, 2017	Total	Gas Utility	Electric Utility
Revenues	$ 621,353	$ 572,964	$ 48,389
Cost of sales — gas, fuel and purchased power	$ 274,012	$ 246,430	$ 27,582
Depreciation and amortization	$ 35,090	$ 32,533	$ 2,557
Operating income	$ 198,644	$ 194,072	$ 4,572
Interest expense	$ 20,350	$ 19,416	$ 934
Income before income taxes	$ 178,294	$ 174,656	$ 3,638
Capital expenditures (including the effects of accruals)	$ 120,613	$ 115,879	$ 4,734
As of March 31, 2017			
Total assets	$ 2,909,725	$ 2,746,144	$ 163,581
Goodwill	$ 182,145	$ 182,145	$ —

Notes to Condensed Consolidated Financial Statements
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		Reportable Segments	
Six Months Ended March 31, 2016	Total	Gas Utility	Electric Utility
Revenues	$ 520,029	$ 475,030	$ 44,999
Cost of sales — gas, fuel and purchased power	$ 212,873	$ 187,931	$ 24,942
Depreciation and amortization	$ 33,731	$ 31,326	$ 2,405
Operating income	$ 162,777	$ 156,824	$ 5,953
Interest expense	$ 18,764	$ 17,913	$ 851
Income before income taxes	$ 144,013	$ 138,911	$ 5,102
Capital expenditures (including the effects of accruals)	$ 109,577	$ 105,273	$ 4,304
As of March 31, 2016			
Total assets	$ 2,639,519	$ 2,486,225	$ 153,294
Goodwill	$ 182,145	$ 182,145	$ —

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) price volatility and availability of oil, electricity and natural gas and the capacity to transport them to market areas; (3) changes in 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) liability for environmental claims; (8) customer conservation measures due to high energy prices and improvements in energy efficiency and technology resulting in reduced demand; (9) adverse labor relations; (10) customer, counterparty, supplier, or vendor defaults; (11) increased uncollectible accounts expense; (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; (13) transmission or distribution system service interruptions; (14) political, regulatory and economic conditions in the United States; (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; and (17) 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 our 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 13 to the condensed consolidated financial statements.

2017 three-month period compared with the 2016 three-month period

Three Months Ended March 31,	2017	2016	Increase (Decrease)	
(Dollars in millions)				
Gas Utility:				
Revenues	$ 335.9	$ 298.1	$ 37.8	12.7 %
Total margin (a)	$ 185.0	$ 174.4	$ 10.6	6.1 %
Operating and administrative expenses	$ 51.3	$ 45.0	$ 6.3	14.0 %
Operating income	$ 115.1	$ 111.0	$ 4.1	3.7 %
Income before income taxes	$ 105.3	$ 102.2	$ 3.1	3.0 %
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 %
Heating degree days — % (warmer) than normal (b)	(11.7)%	(9.7)%	—	—
Electric Utility:				
Revenues	$ 24.1	$ 24.0	$ 0.1	0.4 %
Total margin (a)	$ 9.2	$ 8.9	$ 0.3	3.4 %
Operating and administrative expenses	$ 6.3	$ 3.9	$ 2.4	61.5 %
Operating income	$ 1.3	$ 3.5	$ (2.2)	(62.9)%
Income before income taxes	$ 0.8	$ 3.1	$ (2.3)	(74.2)%
Distribution sales — millions of kilowatt-hours ("gwh")	260.5	265.2	(4.7)	(1.8)%

(a) Gas Utility's total margin represents total revenues less total cost of sales. Electric Utility's 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 "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 the National Oceanic and Atmospheric Administration ("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 $37.9 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 in the three-months ended March 31, 2017, compared with $137.4 million in 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 $10.9 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 ($10.9 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 interest expense in the 2017 three-month period increased slightly principally reflecting higher average long-term debt outstanding. Our effective income tax rate for the three months ended March 31, 2017 was comparable with the prior-year 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 resulting from the adoption of new accounting guidance on share-based payments effective October 1, 2016 (see Note 3 to condensed consolidated financial statements).

2017 six-month period compared with the 2016 six-month period

Six Months Ended March 31,	2017	2016	Increase (Decrease)	
(Dollars in millions)				
Gas Utility:				
Revenues	$ 573.0	$ 475.0	$ 98.0	20.6 %
Total margin (a)	$ 326.6	$ 287.1	$ 39.5	13.8 %
Operating and administrative expenses	$ 95.5	$ 90.4	$ 5.1	5.6 %
Operating income	$ 194.1	$ 156.8	$ 37.3	23.8 %
Income before income taxes	$ 174.7	$ 138.9	$ 35.8	25.8 %
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 %
Heating degree days — % (warmer) than normal (b)	(10.0)%	(16.1)%	—	—
Electric Utility:				
Revenues	$ 48.4	$ 45.0	$ 3.4	7.6 %
Total margin (a)	$ 18.3	$ 17.6	$ 0.7	4.0 %
Operating and administrative expenses	$ 10.7	$ 8.7	$ 2.0	23.0 %
Operating income	$ 4.6	$ 6.0	$ (1.4)	(23.3)%
Income before income taxes	$ 3.6	$ 5.1	$ (1.5)	(29.4)%
Distribution sales — millions of kilowatt-hours ("gwh")	501.1	490.3	10.8	2.2 %

(a) Gas Utility's total margin represents total revenues less total cost of sales. Electric Utility's 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 "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 $101.3 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 in the six months ended March 31, 2017 compared with $212.9 million in the six months ended March 31, 2016, 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 $35.9 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 ($35.9 million), partially offset by slightly higher interest expense.

Interest Expense and Income Taxes

Our interest expense in the 2017 six-month period increased slightly principally reflecting higher average long-term debt outstanding. Our effective income tax rate for the six months ended March 31, 2017, was slightly lower than the prior-year six-month period. The lower 2017 six-month period effective income tax rate is due primarily to the impact 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).

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. Our cash and cash equivalents at March 31, 2017, totaled $4.6 million compared to $2.8 million at September 30, 2016.

UGI Utilities' total debt outstanding at March 31, 2017, was $819.5 million, which includes $48.5 million of short-term borrowings, compared with total debt outstanding of $783.9 million at September 30, 2016, which includes $112.5 million of short-term borrowings. Total long-term debt outstanding at March 31, 2017, comprises $675.0 million of Senior Notes and $100.0 million of Medium-Term Notes, and is net of $4.0 million of unamortized debt issuance costs.

Pursuant to a Note Purchase Agreement, in October 2016, UGI Utilities issued $100 million aggregate principal amount of 4.12% Senior Notes due October 2046 (the "4.12% Senior Notes"). The net proceeds of the issuance of the 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.

UGI Utilities has an unsecured revolving credit agreement (the “UGI Utilities Credit Agreement”) with a group of banks providing for borrowings up to $300 million (including a $100 million sublimit for letters of credit). Borrowings under the UGI Utilities Credit Agreement are classified as “short-term borrowings” on the Condensed Consolidated Balance Sheets. During the 2017 and 2016 six-month periods, average daily short-term borrowings under the UGI Utilities Credit Agreement were $92.4 million and $177.6 million, respectively, and peak short-term borrowings totaled $137.0 million and $232.0 million, respectively. At March 31, 2017, UGI Utilities’ available borrowing capacity under the UGI Utilities Credit Agreement was $249.5 million. Peak short-term borrowings typically occur during the heating season months of December and January when UGI Utilities’ investment in working capital, principally accounts receivable, is generally greatest.

We believe that we have sufficient liquidity in the forms of cash and cash equivalents on hand, cash expected to be generated from Gas Utility and Electric Utility operations, short-term borrowings available under the UGI Utilities Credit Agreement and the ability to refinance long-term debt as it matures to meet our anticipated contractual and projected cash commitments.

Cash Flows

Operating activities. Due to the seasonal nature of UGI Utilities’ businesses, cash flows from our operating activities are generally greatest during the second and third fiscal quarters when customers pay for natural gas and electricity consumed during the peak heating season months. Conversely, operating cash flows are generally at their lowest levels during the first and fourth fiscal quarters when the Company’s investment in working capital, principally accounts receivable and inventories, is generally greatest. UGI Utilities uses borrowings under the UGI Utilities Credit Agreement to manage seasonal cash flow needs.

Cash provided by operating activities was $131.8 million in the 2017 six-month period compared to $152.4 million in the prior-year period. Cash flow from operating activities before changes in operating working capital was $193.0 million in the 2017 six-month period compared to $177.0 million recorded in the prior-year period. The higher cash flow from operations before changes in operating working capital in the 2017 six-month period principally reflects the increase in operating results. Changes in operating working capital used $61.2 million of operating cash flow during the 2017 six-month period compared to $24.6 million of cash used during the prior-year period. The 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 the higher volumes resulting from the colder weather late in the 2017 six-month period and higher natural gas costs.

Investing activities. Cash used by investing activities was $140.6 million in the 2017 six-month period compared to $119.2 million in the 2016 six-month period. Total cash capital expenditures were $135.1 million in the 2017 six-month period compared with $116.8 million recorded in the prior-year period. The increase in cash capital expenditures during the 2017 six-month period principally reflects higher information technology capital expenditures. Changes in restricted cash in futures brokerage accounts provided $0.2 million of cash in the 2017 six-month period compared with $2.7 million in the prior-year period.

Financing activities. Cash provided by financing activities was $10.5 million in the 2017 six-month period compared with cash used by financing activities of $9.9 million during the 2016 six-month period. Financing activity cash flows are primarily the result of net borrowings and repayments under revolving credit agreements, net borrowings and repayments of long-term debt and cash dividends paid to UGI. UGI Utilities issued $100 million of 4.12% Senior Notes during the 2017 six-month period and used the net proceeds principally to reduce short-term borrowings. During the 2017 six-month period there were net credit agreement repayments of $64.0 million compared with net credit agreement borrowings of $83.3 million during the prior-year period. Cash dividends in the 2017 six-month period totaled $25.0 million compared to cash dividends of $22.0 million in the prior-year period.

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 and (2) interest 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

Gas Utility's tariffs contain clauses that permit recovery of all of the prudently incurred costs of natural gas it sells to its retail core-market 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. The change in market value of natural gas futures contracts can require daily deposits of cash in futures accounts. At March 31, 2017, the fair values of our natural gas futures and option contracts were 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 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." The amount of unrealized losses on these contracts and associated volumes under contract at March 31, 2017 were not material.

Interest Rate Risk

In order to reduce interest rate risk associated with near- or medium-term issuances of fixed-rate debt, from time to time we enter into IRPAs. There were no unsettled IRPAs outstanding at March 31, 2017.

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.

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 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):

Exhibit No.	Exhibit	Registrant	Filing	Exhibit
12.1	Computation of ratio of earnings to fixed charges			
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			

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 Utilities, Inc.
(Registrant)

Date: May 5, 2017	By:	/s/ Daniel J. Platt
		Daniel J. Platt Vice President - Finance and Chief Financial Officer
Date: May 5, 2017	By:	/s/ Megan Mattern
		Megan Mattern Controller & Principal Accounting Officer

UGI UTILITIES, INC. AND SUBSIDIARIES

EXHIBIT INDEX

12.1	Computation of ratio of earnings to fixed charges.
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 UTILITIES, INC.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES - EXHIBIT 12.1
(Thousands of dollars)

	Six Months Ended March 31,	Year Ended September 30,			
	2017	2016	2015	2014	2013
Earnings:					
Earnings before income taxes	$ 178,294	$ 163,271	$ 200,539	$ 207,929	$ 171,010
Interest expense	20,157	37,285	40,400	37,897	38,578
Amortization of debt discount and expense	193	345	728	575	731
Estimated interest component of rental expense	1,237	2,512	2,728	2,398	2,090
	$ 199,881	$ 203,413	$ 244,395	$ 248,799	$ 212,409
Fixed Charges:					
Interest expense	$ 20,157	$ 37,285	$ 40,400	$ 37,897	$ 38,578
Amortization of debt discount and expense	193	345	728	575	731
Allowance for funds used during construction (capitalized interest)	556	602	407	227	286
Estimated interest component of rental expense	1,237	2,512	2,728	2,398	2,090
	$ 22,143	$ 40,744	$ 44,263	$ 41,097	$ 41,685
Ratio of earnings to fixed charges	9.03	4.99	5.52	6.05	5.10

EXHIBIT 31.1

CERTIFICATION

I, Robert F. Beard, certify that:

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

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/ Robert F. Beard

Robert F. Beard

President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Daniel J. Platt, certify that:

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

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/ Daniel J. Platt

Daniel J. Platt

Vice President - Finance and Chief Financial Officer

EXHIBIT 32

Certification by the Chief Executive Officer and Chief Financial Officer

Relating to a Periodic Report Containing Financial Statements

I, Robert F. Beard, Chief Executive Officer, and I, Daniel J. Platt, Chief Financial Officer, of UGI Utilities, Inc., 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/ Robert F. Beard	/s/ Daniel J. Platt
Robert F. Beard	Daniel J. Platt
Date: May 5, 2017	Date: May 5, 2017