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 December 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 January 31, 2018, 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)

	December 31, 2017	September 30, 2017	December 31, 2016
ASSETS			
Current assets:			
Cash and cash equivalents	$ 7,289	$ 5,203	$ 9,838
Restricted cash	3,665	3,046	—
Accounts receivable (less allowances for doubtful accounts of $6,398, $4,052 and $5,518, respectively)	105,141	53,720	97,188
Accounts receivable — related parties	1,406	2,807	1,886
Accrued utility revenues	95,854	13,296	55,616
Inventories	49,717	53,309	39,693
Prepaid income taxes	1,977	7,711	2,013
Regulatory assets	605	8,338	1,635
Derivative instruments	678	1,354	7,077
Prepaid expenses & other current assets	23,066	16,406	26,131
Total current assets	289,398	165,190	241,077
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $1,026,450, $1,010,781 and $987,850, respectively)	2,327,664	2,274,548	2,071,718
Goodwill	182,145	182,145	182,145
Regulatory assets	362,237	360,591	391,229
Other assets	13,249	11,541	12,354
Total assets	$ 3,174,693	$ 2,994,015	$ 2,898,523
LIABILITIES AND STOCKHOLDER’S EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 144,374	$ 39,996	$ 39,981
Short-term borrowings	181,500	170,000	98,400
Accounts payable	69,697	71,559	70,703
Accounts payable — related parties	13,420	6,890	11,385
Regulatory liabilities	17,091	12,988	25,830
Derivative instruments	2,244	1,071	295
Other current liabilities	106,177	110,978	113,468
Total current liabilities	534,503	413,482	360,062
Long-term debt	711,242	711,105	731,030
Deferred income taxes	340,772	635,465	566,519
Deferred investment tax credits	2,870	2,950	3,189
Pension and postretirement benefit obligations	140,224	143,674	181,809
Regulatory liabilities	340,391	36,242	32,838
Other noncurrent liabilities	62,670	63,192	63,340
Total liabilities	2,132,672	2,006,110	1,938,787
Commitments and contingencies (Note 8)			
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	473,580
Retained earnings	534,161	480,857	456,781
Accumulated other comprehensive loss	(25,979)	(26,791)	(30,884)
Total common stockholder’s equity	1,042,021	987,905	959,736
Total liabilities and stockholder’s equity	$ 3,174,693	$ 2,994,015	$ 2,898,523

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 December 31,	
	2017	2016
Revenues	$ 323,105	$ 261,413
Costs and expenses:		
Cost of sales — gas, fuel and purchased power (excluding depreciation shown below)	151,774	109,471
Operating and administrative expenses	51,984	49,716
Operating and administrative expenses — related parties	2,689	2,564
Depreciation and amortization	20,354	17,391
Other operating expense, net	9	35
	226,810	179,177
Operating income	96,295	82,236
Interest expense	10,939	10,028
Income before income taxes	85,356	72,208
Income taxes	17,053	27,943
Net income	$ 68,303	$ 44,265

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 December 31,	
	2017	2016
Net income	$ 68,303	$ 44,265
Other comprehensive income:		
Reclassifications of net losses on derivative instruments (net of tax of $(279) and $(351), respectively)	592	495
Benefit plans reclassifications of actuarial losses and net prior service credits (net of tax of $(104) and $(169), respectively)	220	239
Other comprehensive income	812	734
Comprehensive income	$ 69,115	$ 44,999

See accompanying notes to condensed consolidated financial statements.

UGI UTILITIES, INC. AND SUBSIDIARIES

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

	Three Months Ended December 31,	
	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 68,303	$ 44,265
Adjustments to reconcile net income to net cash (used) provided by operating activities:		
Depreciation and amortization	20,354	17,391
Deferred income tax expense	4,328	14,049
Provision for uncollectible accounts	3,459	2,442
Other, net	1,161	4,117
Net change in:		
Accounts receivable and accrued utility revenues	(136,036)	(99,289)
Inventories	3,592	2,647
Deferred fuel and power costs, net of changes in unsettled derivatives	11,572	(1,000)
Accounts payable	21,655	19,358
Other current assets	(6,661)	(4,122)
Other current liabilities	1,172	4,888
Net cash (used) provided by operating activities	(7,101)	4,746
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(88,686)	(69,639)
Net costs of property, plant and equipment disposals	(2,382)	(4,061)
(Increase) decrease in restricted cash	(619)	583
Net cash used by investing activities	(91,687)	(73,117)
CASH FLOWS FROM FINANCING ACTIVITIES		
Payments of dividends	(15,000)	(10,000)
Issuances of long-term debt, net of issuance costs	124,374	99,490
Repayments of long-term debt	(20,000)	—
Increase (decrease) in short-term borrowings	11,500	(14,100)
Net cash provided by financing activities	100,874	75,390
Cash and cash equivalents increase	$ 2,086	$ 7,019
CASH AND CASH EQUIVALENTS		
End of period	$ 7,289	$ 9,838
Beginning of period	5,203	2,819
Increase	$ 2,086	$ 7,019

See accompanying notes to condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Thousands of dollars, except where indicated otherwise)

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 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 herein as an abbreviated reference to UGI Utilities, Inc., or collectively 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, 2017, 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, 2017 ("the Company's 2017 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. 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. From time to time we enter into derivative instruments that are designated and qualify as cash flow hedges. For cash flow hedges, changes in the fair values 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 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. We do not currently have derivative instruments that are designated and qualify as cash flow hedges. 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 11.

Use of Estimates. The preparation of financial statements 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

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). 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.

Restricted Cash. 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 are required to 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" ("ASU 2014-09"). The guidance provided under ASU 2014-09, as amended, supersedes the revenue recognition requirements in ASC No. 605, "Revenue Recognition," and most industry-specific guidance included in the ASC. ASU 2014-09 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 is in the process of analyzing the impact of the new guidance using an integrated approach which includes evaluating differences in the amount and timing of revenue recognition from applying the requirements of the new guidance, reviewing its accounting policies and practices, and assessing the need for changes to its processes, accounting systems and design of internal controls. The Company has completed the assessment of a significant number of its contracts with customers under the new guidance to determine the effect of the adoption of the new guidance. Although the Company has not completed its assessment of the impact of the new guidance, the Company does not expect its adoption will have a material impact on its consolidated financial statements. The Company continues to monitor developments associated with certain utility industry specific guidance for possible impacts on the recognition of revenue.

The Company currently anticipates that it will adopt the new standard using the modified retrospective transition method effective October 1, 2018. The ultimate decision with respect to the transition method that it will use will depend upon the completion of the Company’s analysis including confirming its preliminary conclusion that the adoption of the new guidance will not have a material impact on its consolidated financial statements.

Note 4 — Inventories

Inventories comprise the following:

	December 31, 2017	September 30, 2017	December 31, 2016
Gas Utility natural gas	$ 34,587	$ 39,486	$ 25,777
Materials, supplies and other	15,130	13,823	13,916
Total inventories	$ 49,717	$ 53,309	$ 39,693

At December 31, 2017, UGI Utilities was a party to five principal storage contract administrative agreements (“SCAAs”) which have terms of up 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 13) and one of the SCAAs was 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 December 31, 2017, September 30, 2017 and December 31, 2016, comprising 7.8 billion cubic feet (“bcf”), 9.1 bcf and 7.8 bcf of natural gas, were $22,191, $26,064 and $17,700, respectively. At December 31, 2017, September 30, 2017 and December 31, 2016, UGI Utilities held a total of $13,840, $15,040 and $15,000, 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 13.

Note 5 — Income Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act (the “TCJA”) was enacted into law. The significant changes resulting from the law that impact UGI Utilities include a reduction in the U.S. federal income tax rate from 35% to 21% effective January 1, 2018 (resulting in a blended rate of 24.5% for Fiscal 2018) and the elimination of bonus depreciation for regulated utilities.

In accordance with GAAP as determined by ASC 740, “Income Taxes,” we are required to record the effects of tax law changes in the period enacted. As further discussed below, our results for the three months ended December 31, 2017, contain provisional estimates of the impact of the TCJA. These amounts are considered provisional because they use estimates for which tax returns have not yet been filed and because estimated amounts may be impacted by future regulatory and accounting guidance if and when issued. We will adjust these provisional amounts as further information becomes available and as we refine our calculations. As permitted by recent guidance issued by the SEC, these adjustments will occur during a reasonable “measurement period” not to exceed twelve months from the date of enactment.

As a result, during the three months ended December 31, 2017, we reduced our net deferred income tax liabilities by $223,660 due to the remeasuring of our existing federal deferred income tax assets and liabilities as of the date of enactment. Because a significant amount of the reduction relates to our regulated utility plant assets, most of the reduction to our excess deferred income taxes is not being recognized immediately in income tax expense. During the three months ended December 31, 2017, the amount of the reduction in our net deferred income tax liabilities that reduced income tax expense totaled $8,122.

In order for utility assets to continue to be eligible for accelerated tax depreciation, current law requires that excess deferred income taxes be amortized no more rapidly than over the remaining lives of the assets that gave rise to the excess deferred income taxes. At December 31, 2017, we have recorded a regulatory liability of $216,098 associated with the excess deferred federal income taxes related to our regulated utility plant assets. This regulatory liability has been increased, and a federal deferred income tax asset has been recorded, in the amount of $87,803 to reflect the tax benefit generated by the amortization of the excess deferred federal income taxes. For further information on this regulatory liability, see Note 6 to condensed consolidated financial statements.

For the three months ended December 31, 2017, we included the estimated impacts of the TCJA in determining our estimated annual effective income tax rate. We are subject to a blended federal tax rate of 24.5% for Fiscal 2018 because our fiscal year contains the effective date of the rate change from 35% to 21% on January 1, 2018. As a result, the U.S. federal income tax rate included in our estimated annual effective tax rate is based on this 24.5% blended rate for Fiscal 2018. The PUC has not issued any orders with respect to the lower income tax rate. Our estimated annual effective tax rate for Fiscal 2018 does not reflect the impact of any regulatory action that may be taken by the PUC with respect to the TCJA.

Note 6 — 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 2017 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 the accompanying condensed consolidated balance sheets:

	December 31, 2017	September 30, 2017	December 31, 2016
Regulatory assets:			
Income taxes recoverable	$ 126,509	$ 121,421	$ 117,777
Underfunded pension and postretirement plans	138,287	141,310	179,364
Environmental costs	60,760	61,566	61,437
Deferred fuel and power costs	108	7,685	—
Removal costs, net	31,426	30,996	27,062
Other	5,752	5,951	7,224
Total regulatory assets	$ 362,842	$ 368,929	$ 392,864
Regulatory liabilities:			
Postretirement benefits	$ 17,315	$ 17,493	$ 17,259
Deferred fuel and power refunds	12,658	10,621	23,809
State tax benefits — distribution system repairs	19,101	18,430	15,579
Excess federal deferred income taxes (a)	303,901	—	—
Other	4,507	2,686	2,021
Total regulatory liabilities	$ 357,482	$ 49,230	$ 58,668

(a) Balance at December 31, 2017, comprises excess federal deferred income taxes resulting from the enactment of the TCJA (see below and Note 5).

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 (losses) gains on such contracts at December 31, 2017, September 30, 2017, and December 31, 2016, were $(1,720), $146 and $6,927, respectively.

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 December 31, 2017, September 30, 2017, and December 31, 2016, were not material.

Excess federal deferred income taxes. This regulatory liability is the result of remeasuring UGI Utilities' federal deferred income tax liabilities on utility plant due to the enactment of the TCJA on December 22, 2017 (see Note 5). In order for our utility assets to continue to be eligible for accelerated tax depreciation, current law requires that these excess federal deferred income taxes be amortized no more rapidly than over the remaining lives of the assets that gave rise to the excess federal deferred income taxes, ranging from 1 year to approximately 65 years. This regulatory liability has been increased to reflect the tax benefit generated by the amortization of the excess deferred federal income taxes. This regulatory liability will be amortized and credited to tax expense.

Other Regulatory Matters

Base Rate Filings. On January 26, 2018, Electric Utility filed a rate request with the PUC to increase its annual base distribution revenues by $9,200. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable electric service. Electric Utility requested that the new electric rates become effective March 27, 2018, although the PUC typically suspends the effective date for general base rate proceedings to allow for investigation and public hearings. This review process is expected to last up to nine months; however, the Company cannot predict the timing or the ultimate outcome of the rate case review process.

On August 31, 2017, the PUC approved a previously filed Joint Petition for Approval of Settlement of all issues providing for an $11,250 annual base distribution rate increase for PNG. The increase became effective on October 20, 2017.

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. State legislation permits gas and electric utilities in Pennsylvania to recover a distribution system improvement charge ("DSIC") on eligible capital investments as an alternative ratemaking mechanism providing for a more-timely cost recovery of qualifying capital expenditures between base rate cases.

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 May 2017, the PUC issued a final Order 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 reconsideration at each company's Long-term Infrastructure Improvement Plan filing in 2018. PNG's DSIC has been reset to zero as a result of its most recent rate case. The DSIC rate for PNG will resume upon exceeding the threshold amount of DSIC-eligible plant in service agreed upon in the settlement of its recent base rate case.

In November 2016, UGI Gas received PUC approval to establish a DSIC tariff mechanism, capped at 5% of distribution charges billed to customers, effective January 1, 2017. 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.

Note 7 — Debt

On October 31, 2017, UGI Utilities entered into a $125,000 unsecured variable-rate term loan agreement (the "Term Loan") with a group of banks which initially matures on October 30, 2018. Such maturity will be automatically extended to October 30, 2022, after UGI Utilities receives a securities certificate from the PUC authorizing issuance of the security and upon delivery of such certificate to the agent. Proceeds from the Term Loan were used to repay revolving credit balances and for general corporate purposes. The outstanding principal amount of the Term Loan is payable in equal quarterly installments of $1,563 with the balance of the principal being due and payable in full on the maturity date. Under the Term Loan, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.875% and is based upon the credit ratings of certain indebtedness of UGI Utilities. The Term Loan requires UGI Utilities to not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined. Because UGI Utilities has not yet received a securities certificate from the PUC authorizing the extension of the maturity date to October 30, 2022, the Term Loan has been reflected in "Current maturities of long-term debt" on the December 31, 2017, Condensed Consolidated Balance Sheet.

Note 8 — 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 a consent order and agreement ("COA") with the Pennsylvania Department of Environmental Protection ("DEP") to address the remediation of former MGPs in Pennsylvania. In accordance with the COAs, UGI Utilities, CPG and PNG are each required to either obtain a certain number of points per calendar year based on defined eligible environmental investigatory and/or remedial activities at the MGPs or make expenditures for such activities in an amount equal to an annual environmental cost cap. The CPG COA includes an obligation to plug specified natural gas wells. The COA environmental costs caps are $2,500, $1,750, and $1,100, for UGI Utilities, CPG and PNG, respectively. The COAs for UGI Utilities, CPG and PNG are scheduled to terminate at the end of 2031, 2018, and 2019, respectively. At December 31, 2017, September 30, 2017 and December 31, 2016, our estimated accrued liabilities for environmental investigation and remediation costs related to the COAs for UGI Utilities, CPG and PNG totaled $53,409, $54,250, and $55,300, respectively. UGI Utilities, CPG and PNG have recorded associated regulatory assets for these costs because recovery of these costs from customers is probable (see Note 6).

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

Other Matters

Manor Township, Pennsylvania Natural Gas Explosion. On July 2, 2017, an explosion occurred in Manor Township, Pennsylvania which resulted in the death of a Company employee, significant injuries to two other Company employees and an employee of the local sewer authority, and significant property damage. The National Transportation Safety Board ("NTSB"), the Occupational Safety and Health Administration ("OSHA") and the PUC are investigating the Manor Township incident. The NTSB investigative team includes representatives from the Company, the PUC, the local fire department and the Pipeline and Hazardous Materials Safety Administration and the Company is cooperating with the investigation. The Company continues to provide information requested by the investigating parties.

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(Thousands of dollars, except where indicated otherwise)

While the investigation into this incident is still underway and the cause of the explosion has not been determined, the Company has received claims as a result of the explosion and may become involved in lawsuits relative to the incident. The Company maintains workers' compensation insurance and liability insurance for personal injury, property and casualty damages and believes that third-party claims associated with the explosion, in excess of the Company's deductible, are expected to be recovered through the Company's insurance. Although the Company cannot predict the result of these pending or future claims, we believe that claims and expenses associated with the explosion will not have a material impact on our consolidated financial statements.

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 9 — 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 ("Other Postretirement Plans").

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

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended December 31,	2017	2016	2017	2016
Service cost	$ 1,881	$ 2,023	$ 67	$ 61
Interest cost	5,767	5,539	112	108
Expected return on assets	(7,777)	(7,497)	(177)	(164)
Amortization of:				
Prior service cost (benefit)	63	81	(110)	(160)
Actuarial loss	2,984	3,707	24	28
Net benefit cost (benefit)	2,918	3,853	(84)	(127)
Change in associated regulatory liabilities	—	—	(123)	(122)
Net benefit cost (benefit) after change in regulatory liabilities	$ 2,918	$ 3,853	$ (207)	$ (249)

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, 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 three months ended December 31, 2017 and 2016, the Company made contributions to the Pension Plan of $3,359 and $2,849, respectively. The Company expects to make additional discretionary cash contributions of approximately $10,077 to the Pension Plan during the remainder of Fiscal 2018.

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. The difference between such amount and the amounts included in UGI Gas' and Electric Utility's rates, if any, is deferred for future recovery from, or refund to, ratepayers. There were no required contributions to the VEBA during the three months ended December 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
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Note 10 — 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 December 31, 2017, September 30, 2017 and December 31, 2016:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
December 31, 2017:				
Assets:				
Commodity contracts	$ 678	$ 19	$ —	$ 697
Liabilities:				
Commodity contracts	$ (2,151)	$ (112)	$ —	$ (2,263)
September 30, 2017:				
Assets:				
Commodity contracts	$ 1,735	$ 72	$ —	$ 1,807
Liabilities:				
Commodity contracts	$ (1,447)	$ (73)	$ —	$ (1,520)
December 31, 2016:				
Assets:				
Commodity contracts	$ 7,077	$ —	$ —	$ 7,077
Liabilities:				
Commodity contracts	$ —	$ (295)	$ —	$ (295)

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, 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 types of 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 December 31, 2017, September 30, 2017 and December 31, 2016 were as follows:

	December 31, 2017	September 30, 2017	December 31, 2016
Carrying amount	$ 860,000	$ 755,000	$ 775,000
Estimated fair value	$ 909,283	$ 791,378	$ 800,504

Note 11 — 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,

Notes to Condensed Consolidated Financial Statements
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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 December 31, 2017, September 30, 2017 and December 31, 2016, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 13.4 million dekatherms, 14.8 million dekatherms and 11.7 million dekatherms, respectively. At December 31, 2017, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 9 months. Gains and losses on natural gas futures contracts and natural gas option contracts are recorded in regulatory assets or liabilities on the condensed consolidated balance sheets because it is probable such gains or losses will be recoverable from, or refundable to, customers through the PGC recovery mechanism (see Note 6).

Electric Utility's DS tariffs permit the recovery of all prudently incurred costs of electricity it sells to DS customers, including the cost of financial instruments used to hedge electricity costs. Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. At December 31, 2017, September 30, 2017 and December 31, 2016, all Electric Utility forward electricity purchase contracts were subject to the NPNS exception.

In order to reduce volatility associated with a substantial portion of its electricity transmission congestion costs, Electric Utility obtains FTRs through an annual allocation process. Gains and losses on Electric Utility FTRs are recorded in regulatory assets or liabilities on the condensed consolidated balance sheets because it is probable such gains or losses will be recoverable from, or refundable to, customers through the DS mechanism (see Note 6). At December 31, 2017, September 30, 2017 and December 31, 2016, the total volumes associated with FTRs totaled 63.1 million kilowatt hours, 101.2 million kilowatt hours and 36.2 million kilowatt hours, respectively. At December 31, 2017, the maximum period over which we are economically hedging electricity congestion is 5 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 December 31, 2017, September 30, 2017 and December 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 December 31, 2017, September 30, 2017 and December 31, 2016, we had no unsettled IRPAs. At December 31, 2017, the amount of net losses associated with IRPAs expected to be reclassified into earnings during the next twelve months is $3,485.

Derivative Instrument Credit Risk

Our commodity exchange-traded futures contracts generally require cash deposits in margin accounts. At December 31, 2017 and September 30, 2017, restricted cash in brokerage accounts totaled $3,665 and $3,046, respectively. At December 31, 2016, there were no such amounts.

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

Notes to Condensed Consolidated Financial Statements
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and over-the-counter transactions. Exchange contracts utilize a financial intermediary, exchange or clearinghouse to enter, execute or clear the transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Certain over-the-counter and exchange contracts contain contractual rights of offset through master netting arrangements, derivative clearing agreements and contract default provisions. In addition, the contracts are subject to conditional rights of offset through counterparty nonperformance, insolvency or other conditions.

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

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

	December 31, 2017	September 30, 2017	December 31, 2016
Derivative assets:			
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	$ 450	$ 1,665	$ 6,926
Derivatives not subject to PGC and DS mechanisms:			
Commodity contracts	247	142	151
Total derivative assets — gross	697	1,807	7,077
Gross amounts offset in the balance sheet	(19)	(450)	—
Total derivative assets — net (a)	$ 678	$ 1,357	$ 7,077
Derivative liabilities:			
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	$ (2,263)	$ (1,520)	$ (295)
Total derivative liabilities — gross	(2,263)	(1,520)	(295)
Gross amounts offset in the balance sheet	19	450	—
Total derivative liabilities — net (a)	$ (2,244)	$ (1,070)	$ (295)

(a) Derivative assets and liabilities with maturities greater than one year are recorded in “Other assets” and “Other noncurrent liabilities” on the Condensed Consolidated Balance Sheets.

Notes to Condensed Consolidated Financial Statements
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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 months ended December 31, 2017 and 2016:

Three Months Ended December 31,	Loss Reclassified from AOCI into Income 2017	Loss Reclassified from AOCI into Income 2016	Location of Loss Reclassified from AOCI into Income
Cash Flow Hedges:			
Interest rate contracts	$ (871)	$ (846)	Interest expense

Three Months Ended December 31,	Gain Recognized in Income 2017	Gain Recognized in Income 2016	Location of Gain Recognized in Income
Derivatives Not Subject to PGC and DS Mechanisms:			
Gasoline contracts	$ 149	$ 130	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 because they provide for the delivery of products or services in quantities that are expected to be used in the normal course of operating our business and the price in the contract is based on an underlying that is directly associated with the price of the product or service being purchased or sold.

Note 12 — Accumulated Other Comprehensive Income

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

Three Months Ended December 31, 2017	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — September 30, 2017	$ (8,995)	$ (17,796)	$ (26,791)
Reclassifications of benefit plans actuarial losses and net prior service credits	220	—	220
Reclassifications of net losses on IRPAs	—	592	592
AOCI — December 31, 2017	$ (8,775)	$ (17,204)	$ (25,979)

Three Months Ended December 31, 2016	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — September 30, 2016	$ (11,834)	$ (19,784)	$ (31,618)
Reclassifications of benefit plans actuarial losses and net prior service credits	239	—	239
Reclassifications of net losses on IRPAs	—	495	495
AOCI — December 31, 2016	$ (11,595)	$ (19,289)	$ (30,884)

Note 13 — 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" in 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 totaled $1,046 and $1,169 during the three months ended December 31, 2017 and 2016, respectively.

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 $3,101 and $2,294 during the three months ended December 31, 2017 and 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. These payments totaled $718 and $564 during the three months ended December 31, 2017 and 2016, respectively. 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, at December 31, 2017, September 30, 2017 and December 31, 2016, were $11,040, $11,040, and $11,000, respectively.

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 December 31, 2017, September 30, 2017 and December 31, 2016, comprising approximately 6.1 bcf, 6.8 bcf and 5.9 bcf of natural gas, were $17,043, $19,323 and $12,851, 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 months ended December 31, 2017 and 2016 totaled $34,588 and $30,510, respectively.

From time to time, UGI Utilities sells natural gas or pipeline capacity to Energy Services. During the three months ended December 31, 2017 and 2016, revenues associated with such sales to Energy Services totaled $21,147 and $10,972, 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 months ended December 31, 2017 and 2016, such purchases totaled $37,597 and $22,023, respectively.

Note 14 — 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 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 2017 Annual Report. We evaluate the performance of our Gas Utility and Electric Utility segments principally based upon their income before income taxes.

Notes to Condensed Consolidated Financial Statements
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Financial information by business segment follows:

			Reportable Segments	
Three Months Ended December 31, 2017		Total	Gas Utility	Electric Utility
Revenues		$ 323,105	$ 299,965	$ 23,140
Cost of sales — gas, fuel and purchased power		$ 151,774	$ 138,858	$ 12,916
Depreciation and amortization		$ 20,354	$ 19,000	$ 1,354
Operating income		$ 96,295	$ 93,681	$ 2,614
Interest expense		$ 10,939	$ 10,526	$ 413
Income before income taxes		$ 85,356	$ 83,155	$ 2,201
Capital expenditures (including the effects of accruals)		$ 71,699	$ 68,842	$ 2,857
As of December 31, 2017				
Total assets		$ 3,174,693	$ 3,038,250	$ 136,443
Goodwill		$ 182,145	$ 182,145	$ —

			Reportable Segments	
Three Months Ended December 31, 2016		Total	Gas Utility	Electric Utility
Revenues		$ 261,413	$ 237,100	$ 24,313
Cost of sales — gas, fuel and purchased power		$ 109,471	$ 95,567	$ 13,904
Depreciation and amortization		$ 17,391	$ 16,155	$ 1,236
Operating income		$ 82,236	$ 78,967	$ 3,269
Interest expense		$ 10,028	$ 9,583	$ 445
Income before income taxes		$ 72,208	$ 69,384	$ 2,824
Capital expenditures (including the effects of accruals)		$ 64,096	$ 61,742	$ 2,354
As of December 31, 2016				
Total assets		$ 2,898,523	$ 2,736,908	$ 161,615
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; (17) the interruption, disruption, failure, malfunction, or breach of our information technology systems, including due to cyber attack; and (18) continued analysis of recent tax legislation.

These factors, and those factors set forth in Item 1A. Risk Factors in the Company's 2017 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 December 31, 2017 (“2017 three-month period”) with the three months ended December 31, 2016 (“2016 three-month period”). Our analyses of results of operations should be read in conjunction with the segment information included in Note 14 to the condensed consolidated financial statements.

As further discussed below and in Note 5 to condensed consolidated financial statements, our condensed consolidated balance sheet at December 31, 2017 and our net income for the three months ended December 31, 2017, were significantly affected by the December 22, 2017 enactment of the Tax Cuts and Jobs Act (the “TCJA”). The TCJA includes significant changes to the U.S. Corporate income tax system including a U.S. federal corporate income tax rate reduction from 35% to 21% effective January 1, 2018.

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

Three Months Ended December 31,	2017	2016	Increase (Decrease)	
(Dollars in millions)				
Gas Utility:				
Revenues	$ 300.0	$ 237.1	$ 62.9	26.5 %
Total margin (a)	$ 161.1	$ 141.5	$ 19.6	13.9 %
Operating and administrative expenses	$ 48.4	$ 46.3	$ 2.1	4.5 %
Operating income	$ 93.7	$ 79.0	$ 14.7	18.6 %
Income before income taxes	$ 83.2	$ 69.4	$ 13.8	19.9 %
System throughput — billions of cubic feet (“bcf”)				
Core market	25.5	23.0	2.5	10.9 %
Total	69.2	66.2	3.0	4.5 %
Heating degree days — % (warmer) than normal (b)	(1.9)%	(6.3)%	—	—
Electric Utility:				
Revenues	$ 23.1	$ 24.3	$ (1.2)	(4.9)%
Total margin (a)	$ 8.9	$ 9.1	$ (0.2)	(2.2)%
Operating and administrative expenses	$ 6.3	$ 6.0	$ 0.3	5.0 %
Operating income	$ 2.6	$ 3.3	$ (0.7)	(21.2)%
Income before income taxes	$ 2.2	$ 2.8	$ (0.6)	(21.4)%
Distribution sales — millions of kilowatt-hours (“gwh”)	246.6	240.6	6.0	2.5 %

(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 $1.3 million during each of the three months ended December 31, 2017 and 2016, respectively. For financial statement purposes, revenue-related taxes are included in “Operating and administrative expenses” 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 National Oceanic and Atmospheric Administration for airports located within Gas Utility’s service territory.

Temperatures in Gas Utility’s service territory during the three months ended December 31, 2017, were 1.9% warmer than normal but 6.0% colder than during the three months ended December 31, 2016. Gas Utility core market volumes increased 2.5 bcf (10.9%) principally reflecting the effects of the colder 2017 three-month period weather and growth in the number of core market customers. Total Gas Utility distribution system throughput increased 3.0 bcf principally reflecting the higher core market volumes and slightly higher large firm delivery service volumes. These increases were partially offset by lower interruptible delivery service volumes. Electric Utility kilowatt-hour sales were 2.5% higher than the prior-year period, principally reflecting the impact of the colder weather on Electric Utility heating-related sales.

UGI Utilities revenues increased $61.7 million reflecting a $62.9 million increase in Gas Utility revenues partially offset by slightly lower Electric Utility revenues. The higher Gas Utility revenues principally reflect an increase in core market revenues ($48.1 million), higher off-system sales revenues ($11.5 million), and higher large firm delivery service revenues ($4.4 million). The $48.1 million increase in Gas Utility core market revenues reflects the effects of the higher core market throughput ($18.8 million), higher average retail core market PGC rates ($25.3 million) and the increase in PNG base rates effective October 20, 2017 ($4.0 million). The decrease in Electric Utility revenues principally reflects slightly lower average DS rates ($1.3 million) and lower transmission revenue ($0.4 million) partially offset by the higher Electric Utility volumes. UGI Utilities cost of sales was $151.8 million in the three months ended December 31, 2017 compared with $109.5 million in the three months ended December 31, 2016, principally reflecting higher Gas Utility cost of sales ($43.3 million) partially offset by lower Electric Utility cost of sales ($1.0 million) from lower DS rates. The higher Gas Utility cost of sales reflects higher average retail core market PGC rates ($22.6 million), higher cost of sales associated with Gas Utility off-system sales ($11.5 million), and higher retail core-market volumes ($9.2 million).

UGI Utilities total margin increased $19.4 million principally reflecting higher total margin from Gas Utility core market customers ($16.4 million) and higher large firm delivery service total margin ($3.8 million). The increase in Gas Utility core market margin principally reflects the higher core market throughput ($12.3 million) and the increase in PNG base rates effective October 20, 2017 ($4.0 million). Electric Utility total margin decreased slightly principally reflecting the lower transmission revenue.

UGI Utilities operating income increased $14.0 million, principally reflecting the increase in total margin ($19.4 million) partially offset by higher operating and administrative expenses ($2.4 million) and greater depreciation and amortization expense ($3.0 million) associated with increased capital expenditure activity. The increase in UGI Utilities operating and administrative expenses reflects higher distribution expenses ($1.8 million), higher uncollectible accounts expense ($1.0 million) and higher information technology expenses ($0.7 million) partially offset by a favorable payroll tax adjustment related to prior periods ($2.1 million). UGI Utilities income before income taxes increased $13.1 million reflecting the increase in UGI Utilities operating income ($14.0 million) partially offset by slightly higher interest expense.

Interest Expense and Income Taxes

Interest expense in the 2017 three-month period increased $0.9 million reflecting higher short-term debt interest expense and interest on higher average long-term debt outstanding. Our consolidated income taxes for the three months ended December 31, 2017, were impacted by the enactment of the TCJA which, among other things, reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. We are subject to a blended federal tax rate of 24.5% for Fiscal 2018 because our fiscal year contains the effective date of the rate change from 35% to 21%. As a result of the TCJA, we adjusted our net federal deferred income tax liabilities to remeasure such tax liabilities at the lower corporate rate and certain of these adjustments reduced our income tax expense, and increased net income, by $8.1 million for the three months ended December 31, 2017. In addition to the adjustment to our federal deferred income tax balances, our income taxes for the three months ended December 31, 2017, were further reduced by approximately $8.1 million to reflect the impact of the lower blended income tax rate of 24.5% on our estimated effective income tax rate for Fiscal 2018. The PUC has not issued any orders with respect to the lower income tax rate and our estimated annual effective tax rate for Fiscal 2018 does not reflect the impact of any regulatory action that may be taken by the PUC with respect to the TCJA. For further information on the TCJA, see Note 5 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 December 31, 2017, totaled $7.3 million compared to $5.2 million at September 30, 2017.

UGI Utilities' total debt outstanding at December 31, 2017, was $1,037.1 million, which includes $181.5 million of short-term borrowings, compared with total debt outstanding of $921.1 million at September 30, 2017, which includes $170.0 million of short-term borrowings. Total long-term debt outstanding at December 31, 2017, comprises $675.0 million of Senior Notes, a $125.0 million unsecured term loan and $60.0 million of Medium-Term Notes, and is net of $4.4 million of unamortized debt issuance costs.

On October 31, 2017, UGI Utilities entered into a $125 million unsecured variable-rate term loan agreement (the "Term Loan") with a group of banks which initially matures on October 30, 2018. Such maturity will be automatically extended to October 30, 2022, after UGI Utilities receives a securities certificate from the PUC authorizing issuance of the security and upon delivery of such certificate to the agent. Proceeds from the Term Loan were used to reduce revolving credit balances and for general corporate purposes. The outstanding principal amount of the Term Loan is payable in equal quarterly installments of $1.6 million with the balance of the principal being due and payable in full on the maturity date. Under the Term Loan, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.875% and is based upon the credit ratings of certain indebtedness of UGI Utilities.

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. At December 31, 2017, UGI Utilities' available borrowing capacity under the UGI Utilities Credit Agreement was $116.5 million. During the 2017 and 2016 three-month periods, average daily short-term borrowings under the UGI Utilities Credit Agreement were $168.1 million and $96.6 million, respectively, and peak short-term borrowings totaled $205.0 million and $137.0 million, respectively. 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 used by operating activities was $7.1 million in the 2017 three-month period compared to cash provided by operating activities of $4.7 million in the prior-year period. Cash flow from operating activities before changes in operating working capital was $97.6 million in the 2017 three-month period compared to $82.3 million recorded in the prior-year period. The higher cash flow from operating activities before changes in operating working capital in the 2017 three-month period principally reflects the increase in operating results. Changes in operating working capital used $104.7 million of operating cash flow during the 2017 three-month period compared to $77.5 million of cash used during the prior-year period. The higher cash used in the current period reflects the higher Gas Utility distribution volumes and higher natural gas prices.

Investing activities. Cash used by investing activities was $91.7 million in the 2017 three-month period compared to $73.1 million in the 2016 three-month period. Total cash capital expenditures were $88.7 million in the 2017 three-month period compared with $69.6 million recorded in the prior-year period. The increase in cash capital expenditures during the 2017 three-month period principally reflects the timing of payment of cash for capital expenditures and higher 2017 new business and replacement and betterment expenditures.

Financing activities. Cash provided by financing activities was $100.9 million in the 2017 three-month period compared with $75.4 million during the 2016 three-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 entered into a $125 million unsecured term loan agreement during the 2017 three-month period and used the net proceeds principally to reduce revolving credit balances and for general corporate purposes. During the 2017 three-month period there were net credit agreement borrowings of $11.5 million compared with net credit agreement repayments of $14.1 million during the prior-year period. Cash dividends in the 2017 three-month period totaled $15.0 million compared to cash dividends of $10.0 million in the prior-year period.

IMPACT OF U.S. TAX REFORM

On December 22, 2017, the Tax Cuts and Jobs Act (the "TCJA") was enacted into law. The significant changes resulting from the law that impact UGI Utilities include a reduction in the U.S. federal income tax rate from 35% to 21% effective January 1, 2018 (resulting in a blended rate of 24.5% for Fiscal 2018) and the elimination of bonus depreciation for regulated utilities.

As a result, during the three months ended December 31, 2017, we reduced our net deferred income tax liabilities by $223.7 million due to the remeasuring of our existing federal deferred income tax assets and liabilities as of the date of the enactment. Because a significant amount of the reduction relates to our regulated utility plant assets, most of the reduction to our excess deferred income taxes is not being recognized immediately in income tax expense. During the three months ended December 31, 2017, the amount of the reduction in our net deferred income tax liabilities that reduced income tax expense totaled $8.1 million.

In order for utility assets to continue to be eligible for accelerated tax depreciation, current law requires that excess deferred income taxes be amortized no more rapidly than over the remaining lives of the assets that gave rise to the excess deferred income taxes. At December 31, 2017, we have recorded a regulatory liability of $216.1 million associated with the excess deferred federal income taxes related to our regulated utility plant assets. This regulatory liability has been increased, and a federal deferred income tax asset has been recorded, in the amount of $87.8 million to reflect the tax benefit generated by the amortization of the excess deferred federal income taxes. For further information on this regulatory liability, see Note 6 to condensed consolidated financial statements.

For the three months ended December 31, 2017, we included the estimated impacts of the TCJA in determining our estimated annual effective income tax rate. We are subject to a blended federal tax rate of 24.5% for Fiscal 2018 because our fiscal year contains the effective date of the rate change from 35% to 21% on January 1, 2018. As a result, the U.S. federal income tax rate included in our estimated annual effective tax rate is based on this 24.5% blended rate for Fiscal 2018. The PUC has not issued any orders with respect to the lower income tax rate. Our estimated annual effective tax rate for Fiscal 2018 does not reflect the impact of any regulatory action that may be taken by the PUC with respect to the TCJA.

REGULATORY MATTERS

Base Rate Filings. On January 26, 2018, Electric Utility filed a rate request with the PUC to increase its annual base distribution revenues by $9.2 million. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable electric service. Electric Utility requested that the new electric rates become effective March 27, 2018, although the PUC typically suspends the effective date for general base rate proceedings to allow for investigation and public hearings. This review process is expected to last up to nine months; however, the Company cannot predict the timing or the ultimate outcome of the rate case review process.

On August 31, 2017, the PUC approved a previously filed Joint Petition for Approval of Settlement of all issues providing for an $11.3 million annual base distribution rate increase for PNG. The increase became effective on October 20, 2017.

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. State legislation permits gas and electric utilities in Pennsylvania to recover a distribution system improvement charge (“DSIC”) on eligible capital investments as an alternative ratemaking mechanism providing for a more-timely cost recovery of qualifying capital expenditures between base rate cases.

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 May 2017, the PUC issued a final Order 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 reconsideration at each company’s Long-term Infrastructure Improvement Plan filing in 2018. PNG’s DSIC has been reset to zero as a result of its most recent rate case. The DSIC rate for PNG will resume upon exceeding the threshold amount of DSIC-eligible plant in service agreed upon in the settlement of its recent base rate case.

In November 2016, UGI Gas received PUC approval to establish a DSIC tariff mechanism, capped at 5% of distribution charges billed to customers, effective January 1, 2017. 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.

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 December 31, 2017, the fair values of our natural gas futures and option contracts were losses of $1.7 million.

Electric Utility's DS tariffs contain clauses which permit recovery of all prudently incurred power costs, including the cost of financial instruments used to hedge electricity costs, through the application of DS rates. Because of this ratemaking mechanism, there is limited power cost risk, including the cost of FTRs and forward electricity purchase contracts, associated with our Electric Utility operations. At December 31, 2017, all of our Electric Utility's forward electricity purchase contracts were subject to the NPNS exception. At December 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" on the Condensed Consolidated Statements of Income. The amount of unrealized gains on these contracts and associated volumes under contract at December 31, 2017 were not material.

Interest Rate Risk

Our variable-rate debt at December 31, 2017, includes short-term borrowings and our variable-rate Term Loan. These debt agreements have interest rates that are generally indexed to short-term market interest rates. At December 31, 2017, combined borrowings outstanding under these variable-rate debt agreements totaled $306.5 million.

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 December 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, 2017, 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 December 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 December 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 December 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			

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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: February 6, 2018	By: /s/ Daniel J. Platt Daniel J. Platt Vice President - Finance and Chief Financial Officer
Date: February 6, 2018	By: /s/ Megan Mattern Megan Mattern Controller & Principal Accounting Officer

UGI UTILITIES, INC.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES - EXHIBIT 12.1
(Thousands of dollars)

	Three Months Ended December 31,	Year Ended September 30,			
	2017	2017	2016	2015	2014
Earnings:					
Earnings before income taxes	$ 85,356	$ 188,095	$ 163,271	$ 200,539	$ 207,929
Interest expense	10,833	39,831	37,285	40,400	37,897
Amortization of debt discount and expense	106	381	345	728	575
Estimated interest component of rental expense	583	2,373	2,512	2,728	2,398
	$ 96,878	$ 230,680	$ 203,413	$ 244,395	$ 248,799
Fixed Charges:					
Interest expense	$ 10,833	$ 39,831	$ 37,285	$ 40,400	$ 37,897
Amortization of debt discount and expense	106	381	345	728	575
Allowance for funds used during construction (capitalized interest)	265	1,608	602	407	227
Estimated interest component of rental expense	583	2,373	2,512	2,728	2,398
	$ 11,787	$ 44,193	$ 40,744	$ 44,263	$ 41,097
Ratio of earnings to fixed charges	8.22	5.22	4.99	5.52	6.05

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: February 6, 2018

/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: February 6, 2018

/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 December 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: February 6, 2018	Date: February 6, 2018