UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2018

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 July 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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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2018	September 30, 2017	June 30, 2017
ASSETS			
Current assets:			
Cash and cash equivalents	$ 23,181	$ 5,203	$ 4,828
Restricted cash	805	3,046	2,524
Accounts receivable (less allowances for doubtful accounts of $16,261, $4,052 and $10,050, respectively)	107,966	53,720	69,246
Accounts receivable — related parties	1,682	2,807	718
Accrued utility revenues	14,425	13,296	5,924
Inventories	34,663	53,309	37,129
Prepaid income taxes	41	7,711	428
Regulatory assets	2,180	8,338	7,759
Derivative instruments	1,874	1,354	942
Prepaid expenses & other current assets	19,056	16,406	12,995
Total current assets	205,873	165,190	142,493
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $1,069,070, $1,010,781 and $1,008,121, respectively)	2,430,893	2,274,548	2,174,609
Goodwill	182,145	182,145	182,145
Regulatory assets	357,881	360,591	390,988
Other assets	17,233	11,541	14,297
Total assets	$ 3,194,025	$ 2,994,015	$ 2,904,532
LIABILITIES AND STOCKHOLDER'S EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 9,474	$ 39,996	$ 39,990
Short-term borrowings	118,500	170,000	50,000
Accounts payable	56,297	71,559	56,866
Accounts payable — related parties	14,385	6,890	7,625
Regulatory liabilities	49,664	12,988	15,294
Derivative instruments	—	1,071	1,056
Other current liabilities	119,196	110,978	126,618
Total current liabilities	367,516	413,482	297,449
Long-term debt	830,982	711,105	711,116
Deferred income taxes	336,035	635,465	614,419
Deferred investment tax credits	2,711	2,950	3,029
Pension and postretirement benefit obligations	133,235	143,674	176,393
Regulatory liabilities	362,787	36,242	33,376
Other noncurrent liabilities	60,954	63,192	61,732
Total liabilities	2,094,220	2,006,110	1,897,514
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	590,321	480,857	502,603
Accumulated other comprehensive loss	(24,355)	(26,791)	(29,424)
Total common stockholder's equity	1,099,805	987,905	1,007,018
Total liabilities and stockholder's equity	$ 3,194,025	$ 2,994,015	$ 2,904,532

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 June 30,		Nine Months Ended June 30,	
	2018	2017	2018	2017
Revenues	$ 159,934	$ 146,692	$ 966,300	$ 768,045
Costs and expenses:				
Cost of sales — gas and purchased power (excluding depreciation shown below)	72,537	51,979	481,613	325,991
Operating and administrative expenses	58,225	52,737	177,263	160,474
Operating and administrative expenses — related parties	4,325	2,961	10,780	10,059
Depreciation and amortization	21,414	17,912	62,926	53,002
Other operating income, net	(481)	(6,568)	(1,618)	(7,796)
	156,020	119,021	730,964	541,730
Operating income	3,914	27,671	235,336	226,315
Interest expense	10,003	10,128	32,033	30,478
(Loss) income before income taxes	(6,089)	17,543	203,303	195,837
Income tax (benefit) expense	(3,066)	6,846	48,839	75,750
Net (loss) income	$ (3,023)	$ 10,697	$ 154,464	$ 120,087

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 June 30,		Nine Months Ended June 30,	
	2018	2017	2018	2017
Net (loss) income	$ (3,023)	$ 10,697	$ 154,464	$ 120,087
Other comprehensive income:				
Reclassifications of net losses on derivative instruments (net of tax of $(279), $(355), $(838) and $(1,047), respectively)	592	501	1,776	1,477
Benefit plans reclassifications of actuarial losses and net prior service credits (net of tax of $(104), $(169), $(312) and $(507), respectively)	220	239	660	717
Other comprehensive income	812	740	2,436	2,194
Comprehensive (loss) income	$ (2,211)	$ 11,437	$ 156,900	$ 122,281

See accompanying notes to condensed consolidated financial statements.

UGI UTILITIES, INC. AND SUBSIDIARIES

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

	Nine Months Ended June 30, 2018	Nine Months Ended June 30, 2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 154,464	$ 120,087
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	62,926	53,002
Deferred income tax (benefit) expense	(6,024)	56,285
Provision for uncollectible accounts	16,462	8,184
Regulatory impact from tax reform	24,098	—
Other, net	(1,635)	4,358
Net change in:		
Accounts receivable and accrued utility revenues	(70,726)	(31,471)
Inventories	18,646	5,211
Deferred fuel and power costs, net of changes in unsettled derivatives	39,657	(12,571)
Accounts payable	3,655	2,775
Other current assets	(2,650)	9,014
Other current liabilities	16,725	21,727
Net cash provided by operating activities	255,598	236,601
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(217,901)	(201,916)
Net costs of property, plant and equipment disposals	(5,682)	(7,734)
Decrease (increase) in restricted cash	2,241	(1,941)
Net cash used by investing activities	(221,342)	(211,591)
CASH FLOWS FROM FINANCING ACTIVITIES		
Payments of dividends	(45,000)	(40,000)
Issuances of long-term debt, net of issuance costs	124,404	99,499
Repayments of long-term debt	(44,182)	(20,000)
Decrease in short-term borrowings	(51,500)	(62,500)
Net cash used by financing activities	(16,278)	(23,001)
Cash and cash equivalents increase	$ 17,978	$ 2,009
CASH AND CASH EQUIVALENTS		
End of period	$ 23,181	$ 4,828
Beginning of period	5,203	2,819
Increase	$ 17,978	$ 2,009

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 ("MD PSC"), 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 normal purchase and normal sale ("NPNS") exception is elected. The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is subject to regulatory ratemaking mechanisms or if it qualifies and is designated as a hedge for accounting purposes.

Gains and losses on substantially all of the derivative instruments used by UGI Utilities to hedge commodity prices (for which NPNS has not been elected) are included in regulatory assets and liabilities. From time to time we enter into derivative instruments that qualify and are designated 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 unsettled 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

Other Comprehensive Income. In February 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2018-02, “Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.” This ASU provides that the stranded tax effects in AOCI resulting from the Tax Cuts and Jobs Act (the “TCJA”) may be reclassified to retained earnings, at the election of the entity, in the period of adoption. The amendments in this ASU are effective for interim and annual periods beginning after December 15, 2018 (Fiscal 2020). Early adoption is permitted. We currently expect to adopt this ASU effective October 1, 2018. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance but does not expect its adoption will have a material impact on its consolidated financial statements.

Pension and Other Postretirement Benefit Costs. In March 2017, the FASB issued 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 income from operations. The amendments in this ASU permit only the service cost component to be eligible for capitalization when applicable. For entities subject to rate regulation, however, the ASU recognized that in the event a regulator continues to require capitalization of all net periodic benefit costs prospectively, the difference would result in the recognition of a regulatory asset or liability. The amendments in this ASU are effective for interim and annual periods beginning after December 15, 2017 (Fiscal 2019) with a retrospective adoption for income statement presentation and a prospective adoption for capitalization. We will adopt this ASU effective October 1, 2018. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance but does not expect its adoption will have a material impact on its consolidated financial statements.

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 the ASU are required to be adopted on a retrospective basis. The ASU is effective for interim and annual periods beginning after December 15, 2017 (Fiscal 2019). Early adoption is permitted. We currently expect to adopt this ASU effective October 1, 2018. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance but does not expect its adoption will have a material impact on its consolidated financial statements.

Leases. In February 2016, the FASB issued ASU No. 2016-02, "Leases." This ASU, as subsequently updated, 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. In July 2018, the FASB issued ASU No. 2018-11, “Leases: Targeted Improvements.” Among other things, this ASU provides entities with a transition option to recognize the cumulative-effect adjustment from the modified retrospective application to the opening balance of retained earnings in the period of adoption rather than the earliest period presented in the financial statements. We currently expect to adopt ASU No. 2016-02, as updated, effective October 1, 2019. The Company has not yet selected a transition method and is currently in the process of assessing the impact on its financial statements from the adoption of ASU No. 2016-02 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 Accounting Standards Codification (“ASC”) No. 605, “Revenue Recognition,” and most industry-specific guidance included in

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

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 anticipates that it will adopt the new standard using the modified retrospective transition method effective October 1, 2018.

Note 4 — Inventories

Inventories comprise the following:

	June 30, 2018	September 30, 2017	June 30, 2017
Gas Utility natural gas	$ 18,608	$ 39,486	$ 21,826
Materials, supplies and other	16,055	13,823	15,303
Total inventories	$ 34,663	$ 53,309	$ 37,129

At June 30, 2018, 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 the 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 June 30, 2018, September 30, 2017 and June 30, 2017, comprising 4.7 billion cubic feet ("bcf"), 9.1 bcf and 4.8 bcf of natural gas, were $11,944, $26,064 and $14,146, respectively. At June 30, 2018, September 30, 2017 and June 30, 2017, UGI Utilities held a total of $13,840, $15,040 and $15,040, 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 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 and nine months ended June 30, 2018, 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. In accordance with SEC Staff Accounting Bulletin (“SAB”) No. 118, we will adjust these provisional amounts as further information becomes available and as we refine our calculations. As permitted by SAB No. 118 these adjustments will occur during a reasonable “measurement period” not to exceed twelve months from the date of enactment.

As a result of the TCJA, in December 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 the TCJA enactment. Because a significant amount of the reduction relates to our regulated utility plant assets, most of the reduction to our deferred income taxes is not being recognized immediately in income tax expense. During the three and nine months ended June 30, 2018, the amount of the reduction in our net deferred income tax liabilities that reduced income tax expense, including adjustments to provisional amounts previously recorded, totaled $1,131 and $9,254, respectively.

In order for utility assets to continue to be eligible for accelerated tax depreciation, current law requires that excess deferred federal income taxes resulting from the measurement of deferred taxes on regulated utility plant be amortized no more rapidly than over the remaining lives of the assets that gave rise to the excess deferred income taxes. In December 2017, we 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 was increased, and a federal deferred income tax asset recorded, in the amount of $87,803 to reflect the tax benefit generated by the amortization of the excess deferred federal income taxes. This regulatory liability is being amortized to income tax expense over the remaining lives of the assets that gave rise to the excess deferred income taxes. For further information on these regulatory assets and liabilities, see Note 6.

For the three and nine months ended June 30, 2018, 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 the 24.5% blended rate for Fiscal 2018. For the three and nine months ended June 30, 2018, the effects of the tax law changes on current-period results (excluding the one-time impacts described above) decreased income tax expense by approximately $782 and $24,051, respectively.

As further described in Note 6, on May 17, 2018, the PUC issued a Temporary Rates Order for all PUC-regulated utilities with regard to the TCJA. Among other things, the Temporary Rates Order requires Pennsylvania utilities to establish a regulatory liability for tax benefits that accrued during the period January 1, 2018 through June 30, 2018, resulting from the change in the federal income tax rate from 35% to 21%. In order to reflect the effects of the tax savings from the change in the federal income tax rate for the period January 1, 2018 to June 30, 2018, during the three months ended June 30, 2018, UGI Utilities reduced its combined utility revenues by $22,745 (which is in addition to a $1,353 reduction previously recorded in March 2018), and recorded a regulatory liability in an equal amount. The total reduction in revenues for the nine months ended June 30, 2018 of $24,098 reflects (1) $17,135 of tax benefits accrued during the period January 1, 2018, to June 30, 2018, plus (2) $6,963 to reflect tax benefits expected to be generated by the future amortization of the regulatory liability.

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 our accompanying condensed consolidated balance sheets:

	June 30, 2018	September 30, 2017	June 30, 2017
Regulatory assets:			
Income taxes recoverable	$ 130,024	$ 121,421	$ 122,733
Underfunded pension and postretirement plans	132,239	141,310	171,833
Environmental costs	59,808	61,566	61,616
Deferred fuel and power costs	190	7,685	7,024
Removal costs, net	30,987	30,996	29,405
Other	6,813	5,951	6,136
Total regulatory assets	$ 360,061	$ 368,929	$ 398,747
Regulatory liabilities:			
Postretirement benefits	$ 16,895	$ 17,493	$ 16,715
Deferred fuel and power refunds	44,500	10,621	12,587
State tax benefits — distribution system repairs	20,677	18,430	16,662
PUC Temporary Rates Order (a)	24,098	—	—
Excess federal deferred income taxes (b)	301,151	—	—
Other	5,130	2,686	2,706
Total regulatory liabilities	$ 412,451	$ 49,230	$ 48,670

(a) Balance at June 30, 2018, comprises tax savings for the period January 1, 2018 to June 30, 2018 resulting from the enactment of the TCJA (see "PUC Temporary Rates Order" below and Note 5).

(b) Balance at June 30, 2018, comprises excess federal deferred income taxes resulting from the enactment of the TCJA (see "Excess federal deferred income taxes" 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 gains (losses) on such contracts at June 30, 2018, September 30, 2017, and June 30, 2017, were $1,863, $146 and $(73), respectively.

In order to reduce volatility associated with a substantial portion of its electric transmission congestion costs, Electric Utility, from time to time, 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 September 30, 2017, and June 30, 2017, were not material. There were no open FTR positions as of June 30, 2018.

PUC Temporary Rates Order. By Secretarial Letter dated January 12, 2018, the PUC initiated a review into whether public utility rates should be adjusted to reflect the tax savings from the change in the federal income tax rate from 35% to 21% for the period

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

beginning January 1, 2018. Thereafter, on March 15, 2018, the PUC entered a Temporary Rates Order that converted commission-approved rates of most large Pennsylvania public utilities, including Gas Utility, into “temporary rates” for a period of no more than 12 months while the PUC reviewed the data and comments in response to the Secretarial Letter.

On May 17, 2018, the PUC ordered each regulated utility currently not in a general base rate case proceeding, including UGI Gas, PNG and CPG, to reduce their rates through the establishment of a negative surcharge applied to bills rendered on or after July 1, 2018. The temporary negative surcharge will be reconciled at the end of each fiscal year to actual tax savings realized. The negative surcharge will remain in place until the effective date of new rates established in the utility’s next general base rate proceeding. For UGI Gas, PNG and CPG, such negative surcharge will reduce base rate revenues by 5.78%, 3.90% and 8.19%, respectively.

In its May 17, 2018 Order, the PUC also required Pennsylvania utilities to establish a regulatory liability for tax benefits that accrued during the period beginning January 1, 2018 through June 30, 2018, resulting from the reduced federal tax rate. For UGI Gas, PNG and CPG, during the three months ended June 30, 2018, UGI Utilities reduced its combined utility revenues by $22,745 (which is in addition to a $1,353 reduction previously recorded in March 2018), and recorded a regulatory liability in an equal amount. The total reduction in revenues for the nine months ended June 30, 2018 reflects (1) $17,135 of tax benefits accrued during the previously mentioned six-month period plus (2) $6,963 to reflect tax benefits expected to be generated by the future amortization of the regulatory liability. The rate treatment of this regulatory liability, including accrued interest, for each of UGI Gas, PNG and CPG will be addressed in a future proceeding. Like other similarly situated utilities, if UGI Gas, PNG or CPG have not filed a general base rate proceeding within three years of the Temporary Rates Order, UGI Gas, PNG and CPG will be required to file a petition to propose how to distribute the balance of these regulatory liabilities.

For Pennsylvania utilities currently in a general base rate proceeding, including Electric Utility, no negative surcharge will apply, and such tax benefits will be handled through that proceeding, including the benefits that accrue during the period beginning January 1, 2018 until the effective date of new base rates established in the proceeding. At June 30, 2018, such amount for Electric Utility was 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 excess federal deferred income taxes resulting from the remeasurement 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 and 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, which was later reduced by the Company to $7,700 to reflect the impact of the TCJA and other adjustments. 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. The PUC entered an Order dated March 1, 2018, suspending the effective date for the rate increase to allow for investigation and public hearings in a review process that is expected to last up to nine months from the date of filing. The matter is currently pending before two PUC administrative law judges who are expected to issue a recommended decision that will be the subject of a final decision by the PUC. Although the Company expects to receive a final decision from the PUC in October 2018, 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. PNG's DSIC has been reset to zero as a result of its most recent base rate case. The DSIC rate for PNG will resume upon exceeding the threshold amount of DSIC-eligible plant in service agreed upon during the settlement of its most 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 began recovering revenue under the mechanism effective July 1, 2018 for the amount of DSIC-eligible plant placed into service as it exceeded the threshold amount of DSIC-eligible plant agreed upon in the settlement of its recent base rate case in the third quarter of Fiscal 2018.

Utilities Merger Request. On March 8, 2018 and March 13, 2018, the Company filed merger authorization requests with the PUC and MD PSC, respectively, to merge PNG and CPG into UGI Utilities, with a targeted effective date of October 1, 2018. There are no expected changes to annual base distribution rates for the combined utilities or to existing regulatory assets and liabilities as a result of the proposed merger. On July 20, 2018, the Company filed a Joint Petition for Settlement among the parties to the proceeding for approval by two administrative law judges by recommended decision that will be the subject of a final decision by the PUC. On July 25, 2018, the MD PSC issued an order approving the Company's merger request. The Company cannot predict the timing or the ultimate outcome of the PUC review of the merger request. On August 3, 2018, the Federal Energy Regulatory Commission ("FERC") approved requests made by CPG, PNG, and UGI Utilities in May 2018 relating to the transfer of certain FERC authorizations from PNG and CPG to UGI Utilities, to ensure continuity of certain interstate gas transportation services currently conducted by CPG and PNG after the effective date of the proposed merger. With the receipt of these FERC approvals, the approval of an application to transfer CPG's service territory designation to UGI Utilities remains the only FERC approval yet to be received in connection with the proposed merger.

Note 7 — Debt

In October 2017, UGI Utilities entered into a $125,000 unsecured variable-rate term loan agreement (the "Term Loan") with a group of banks. Proceeds from the Term Loan were used to repay revolving credit agreement borrowings and for general corporate purposes. The Term Loan is payable in equal quarterly installments of $1,563 commencing March 2018, with the balance of the principal being due and payable in full on October 30, 2022. 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 that UGI Utilities not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined.

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 currently scheduled to terminate at the end of 2031, 2018, and 2019, respectively. At June 30, 2018, September 30, 2017 and June 30, 2017, our estimated accrued liabilities for environmental investigation and remediation costs related to the COAs for UGI Utilities, CPG and PNG totaled $52,231, $54,250, and $55,185, 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 June 30, 2018, September 30, 2017 and June 30, 2017, 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") 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. The Occupational Safety and Health Administration has closed its investigation with no findings.

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").

Notes to Condensed Consolidated Financial Statements
(unaudited)
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Net periodic pension expense and other postretirement benefit costs include the following components:

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended June 30,	2018	2017	2018	2017
Service cost	$ 1,882	$ 2,023	$ 66	$ 62
Interest cost	5,766	5,540	111	108
Expected return on assets	(7,776)	(7,497)	(178)	(164)
Amortization of:				
Prior service cost (benefit)	61	81	(110)	(160)
Actuarial loss	2,984	3,706	23	28
Net benefit cost (benefit)	2,917	3,853	(88)	(126)
Change in associated regulatory liabilities	—	—	(122)	(123)
Net benefit cost (benefit) after change in regulatory liabilities	$ 2,917	$ 3,853	$ (210)	$ (249)

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended June 30,	2018	2017	2018	2017
Service cost	$ 5,644	$ 6,068	$ 200	$ 184
Interest cost	17,300	16,618	335	323
Expected return on assets	(23,330)	(22,490)	(532)	(492)
Amortization of:				
Prior service cost (benefit)	187	244	(330)	(480)
Actuarial loss	8,952	11,119	71	85
Net benefit cost (benefit)	8,753	11,559	(256)	(380)
Change in associated regulatory liabilities	—	—	(368)	(368)
Net benefit cost (benefit) after change in regulatory liabilities	$ 8,753	$ 11,559	$ (624)	$ (748)

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 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 nine months ended June 30, 2018 and 2017, the Company made contributions to the Pension Plan of $10,079 and $8,546, respectively. The Company expects to make additional cash contributions of approximately $5,000 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 cash deposits or expense recorded 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 nine months ended June 30, 2018 and 2017.

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.

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 June 30, 2018, September 30, 2017 and June 30, 2017:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
June 30, 2018:				
Assets:				
Commodity contracts	$ 2,097	$ —	$ —	$ 2,097
Liabilities:				
Commodity contracts	$ (101)	$ —	$ —	$ (101)
September 30, 2017:				
Assets:				
Commodity contracts	$ 1,735	$ 72	$ —	$ 1,807
Liabilities:				
Commodity contracts	$ (1,447)	$ (73)	$ —	$ (1,520)
June 30, 2017:				
Assets:				
Commodity contracts	$ 1,062	$ 101	$ —	$ 1,163
Liabilities:				
Commodity contracts	$ (1,157)	$ (68)	$ —	$ (1,225)

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 June 30, 2018, September 30, 2017 and June 30, 2017 were as follows:

	June 30, 2018	September 30, 2017	June 30, 2017
Carrying amount	$ 844,672	$ 755,000	$ 755,000
Estimated fair value	$ 858,960	$ 791,378	$ 788,472

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, 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 June 30, 2018, September 30, 2017 and June 30, 2017, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 16.8 million dekatherms, 14.8 million dekatherms and 12.7 million dekatherms, respectively. At June 30, 2018, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 16 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 June 30, 2018, September 30, 2017 and June 30, 2017, 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 June 30, 2018, there were no volumes associated with FTRs. At September 30, 2017 and June 30, 2017, the total volumes associated with FTRs totaled 101.2 million kilowatt hours and 139.4 million kilowatt hours, respectively.

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 June 30, 2018, September 30, 2017 and June 30, 2017, 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 June 30, 2018, September 30, 2017 and June 30, 2017, we had no unsettled IRPAs. At June 30, 2018, 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 June 30, 2018, September 30, 2017 and June 30, 2017, restricted cash in brokerage accounts totaled $805, $3,046 and $2,524, respectively.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities are presented net by counterparty on the condensed consolidated balance sheets if the right of offset exists. Our derivative instruments include both those that are executed on an exchange through brokers and centrally cleared and over-the-counter transactions. Exchange contracts utilize a financial intermediary, exchange or clearinghouse to enter, execute 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 June 30, 2018, September 30, 2017 and June 30, 2017:

	June 30, 2018	September 30, 2017	June 30, 2017
Derivative assets:			
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	$ 1,963	$ 1,665	$ 1,163
Derivatives not subject to PGC and DS mechanisms:			
Commodity contracts	134	142	—
Total derivative assets — gross	2,097	1,807	1,163
Gross amounts offset in the balance sheet	(101)	(450)	(159)
Total derivative assets — net (a)	$ 1,996	$ 1,357	$ 1,004
Derivative liabilities:			
Derivatives subject to PGC and DS mechanisms:			
Commodity contracts	$ (101)	$ (1,520)	$ (1,204)
Derivatives not subject to PGC and DS mechanisms:			
Commodity contracts	—	—	(21)
Total derivative liabilities — gross	(101)	(1,520)	(1,225)
Gross amounts offset in the balance sheet	101	450	159
Total derivative liabilities — net (a)	$ —	$ (1,070)	$ (1,066)

(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
(unaudited)
(Thousands of dollars, except where indicated otherwise)

Effect of Derivative Instruments

The following table provides information on the effects of derivative instruments not subject to ratemaking mechanisms on the condensed consolidated statements of income and changes in AOCI for the three and nine months ended June 30, 2018 and 2017:

	Loss Reclassified from AOCI into Income		Location of Loss Reclassified from AOCI into Income
Three Months Ended June 30,	2018	2017	
Cash Flow Hedges:			
Interest rate contracts	$ (871)	$ (856)	Interest expense

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Three Months Ended June 30,	2018	2017	
Derivatives Not Subject to PGC and DS Mechanisms:			
Commodity contracts	$ 37	$ (57)	Operating and administrative expenses

	Loss Reclassified from AOCI into Income		Location of Loss Reclassified from AOCI into Income
Nine Months Ended June 30,	2018	2017	
Cash Flow Hedges:			
Interest rate contracts	$ (2,614)	$ (2,524)	Interest expense

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Nine Months Ended June 30,	2018	2017	
Derivatives Not Subject to PGC and DS Mechanisms:			
Commodity contracts	$ 198	$ (25)	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.

Notes to Condensed Consolidated Financial Statements
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Note 12 — Accumulated Other Comprehensive Income

The tables below present changes in AOCI, net of tax, during the three and nine months ended June 30, 2018 and 2017:

Three Months Ended June 30, 2018	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — March 31, 2018	$ (8,555)	$ (16,612)	$ (25,167)
Reclassifications of benefit plan actuarial losses and net prior service credits	220	—	220
Reclassifications of net losses on IRPAs	—	592	592
AOCI — June 30, 2018	$ (8,335)	$ (16,020)	$ (24,355)

Three Months Ended June 30, 2017	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI — March 31, 2017	$ (11,356)	$ (18,808)	$ (30,164)
Reclassifications of benefit plan actuarial losses and net prior service credits	239	—	239
Reclassifications of net losses on IRPAs	—	501	501
AOCI — June 30, 2017	$ (11,117)	$ (18,307)	$ (29,424)

Nine Months Ended June 30, 2018	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	660	—	660
Reclassifications of net losses on IRPAs	—	1,776	1,776
AOCI — June 30, 2018	$ (8,335)	$ (16,020)	$ (24,355)

Nine Months Ended June 30, 2017	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	717	—	717
Reclassifications of net losses on IRPAs	—	1,477	1,477
AOCI — June 30, 2017	$ (11,117)	$ (18,307)	$ (29,424)

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. UGI Utilities also engages in other services with various other affiliates pursuant to arrangements authorized by the PUC using similar allocation or market-based pricing methods. 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 $1,665 and $562 during the three months ended June 30, 2018 and 2017, respectively, and $4,070 and $3,420 during the nine months ended June 30, 2018 and 2017, 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 $8,114 and $9,777 during the three months ended June 30, 2018 and 2017, respectively, and $11,394 and $12,272 during the nine months ended June 30, 2018 and 2017, 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 $701 and $729 during the three months ended June 30, 2018 and 2017, respectively, and $2,127 and $2,027 during the nine months ended June 30, 2018 and 2017, 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 June 30, 2018, September 30, 2017 and June 30, 2017, were $11,040.

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 June 30, 2018, September 30, 2017 and June 30, 2017, comprising approximately 3.6 bcf, 6.8 bcf and 3.6 bcf of natural gas, were $9,294, $19,323 and $10,662, 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 June 30, 2018 and 2017 totaled $5,828 and $2,137, respectively, and during the nine months ended June 30, 2018 and 2017 totaled $87,782 and $73,872, respectively.

From time to time, UGI Utilities sells natural gas or pipeline capacity to Energy Services. During the three months ended June 30, 2018 and 2017, revenues associated with such sales to Energy Services totaled $11,582 and $10,554, respectively. During the nine months ended June 30, 2018 and 2017, revenues associated with such sales to Energy Services totaled $93,974 and $43,836, 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 June 30, 2018 and 2017, such purchases totaled $19,429 and $14,675, respectively. During the nine months ended June 30, 2018 and 2017, such purchases totaled $140,455 and $75,783, 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
(unaudited)
(Thousands of dollars, except where indicated otherwise)

Financial information by business segment follows:

Three Months Ended June 30, 2018	Total		Reportable Segments Gas Utility		Reportable Segments Electric Utility	
Revenues	$	159,934	$	138,597	$	21,337
Cost of sales — gas and purchased power	$	72,537	$	60,837	$	11,700
Depreciation and amortization	$	21,414	$	20,011	$	1,403
Operating income	$	3,914	$	2,628	$	1,286
Interest expense	$	10,003	$	9,829	$	174
(Loss) income before income taxes	$	(6,089)	$	(7,201)	$	1,112
Capital expenditures (including the effects of accruals)	$	79,704	$	76,546	$	3,158

Three Months Ended June 30, 2017	Total		Reportable Segments Gas Utility		Reportable Segments Electric Utility	
Revenues	$	146,692	$	127,849	$	18,843
Cost of sales — gas and purchased power	$	51,979	$	42,180	$	9,799
Depreciation and amortization	$	17,912	$	16,845	$	1,067
Operating income	$	27,671	$	25,628	$	2,043
Interest expense	$	10,128	$	9,601	$	527
Income before income taxes	$	17,543	$	16,027	$	1,516
Capital expenditures (including the effects of accruals)	$	79,088	$	75,836	$	3,252

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

			Reportable Segments	
Nine Months Ended June 30, 2018		Total	Gas Utility	Electric Utility
Revenues		$ 966,300	$ 894,535	$ 71,765
Cost of sales — gas and purchased power		$ 481,613	$ 440,726	$ 40,887
Depreciation and amortization		$ 62,926	$ 58,787	$ 4,139
Operating income		$ 235,336	$ 230,484	$ 4,852
Interest expense		$ 32,033	$ 31,221	$ 812
Income before income taxes		$ 203,303	$ 199,263	$ 4,040
Capital expenditures (including the effects of accruals)		$ 206,492	$ 196,751	$ 9,741
As of June 30, 2018				
Total assets		$ 3,194,025	$ 3,008,441	$ 185,584
Goodwill		$ 182,145	$ 182,145	$ —

			Reportable Segments	
Nine Months Ended June 30, 2017		Total	Gas Utility	Electric Utility
Revenues		$ 768,045	$ 700,813	$ 67,232
Cost of sales — gas and purchased power		$ 325,991	$ 288,610	$ 37,381
Depreciation and amortization		$ 53,002	$ 49,378	$ 3,624
Operating income		$ 226,315	$ 219,700	$ 6,615
Interest expense		$ 30,478	$ 29,017	$ 1,461
Income before income taxes		$ 195,837	$ 190,683	$ 5,154
Capital expenditures (including the effects of accruals)		$ 199,701	$ 191,715	$ 7,986
As of June 30, 2017				
Total assets		$ 2,904,532	$ 2,743,035	$ 161,497
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 June 30, 2018 ("2018 three-month period") with the three months ended June 30, 2017 ("2017 three-month period") and the nine months ended June 30, 2018 ("2018 nine-month period") with the nine months ended June 30, 2017 ("2017 nine-month period"). Our analyses of results of operations should be read in conjunction with the segment information included in Note 14 to the condensed consolidated financial statements.

As further discussed below and in Note 5 to the condensed consolidated financial statements, our condensed consolidated balance sheet at June 30, 2018 and our net income for the three and nine months ended June 30, 2018, 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.

2018 three-month period compared with the 2017 three-month period

Three Months Ended June 30,	2018	2017	Increase (Decrease)	
(Dollars in millions)				
Gas Utility:				
Revenues (a)	$ 138.6	$ 127.8	$ 10.8	8.5 %
Total margin (a)(b)	$ 77.8	$ 85.6	$ (7.8)	(9.1)%
Operating and administrative expenses	$ 55.5	$ 49.7	$ 5.8	11.7 %
Operating income	$ 2.6	$ 25.6	$ (23.0)	(89.8)%
(Loss) income before income taxes	$ (7.2)	$ 16.0	$ (23.2)	(145.0)%
System throughput — billions of cubic feet ("bcf")				
Core market	11.4	8.7	2.7	31.0 %
Total	53.7	46.5	7.2	15.5 %
Heating degree days — % colder (warmer) than normal (c)	5.1%	(21.2)%	—	—
Electric Utility:				
Revenues	$ 21.3	$ 18.8	$ 2.5	13.3 %
Total margin (b)	$ 8.5	$ 8.0	$ 0.5	6.3 %
Operating and administrative expenses (b)	$ 6.1	$ 5.0	$ 1.1	22.0 %
Operating income	$ 1.3	$ 2.0	$ (0.7)	(35.0)%
Income before income taxes	$ 1.1	$ 1.5	$ (0.4)	(26.7)%
Distribution sales — millions of kilowatt-hours ("gwh")	221.7	209.5	12.2	5.8 %

(a) In accordance with a PUC Order issued May 17, 2018, Gas Utility's revenues and total margin for the three months ended June 30, 2018, were reduced by $22.7 million to record a regulatory liability related to tax savings for the period January 1, 2018 to June 30, 2018 as a result of the TCJA (see Notes 5 and 6 to condensed consolidated financial statements).

(b) 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 $1.1 million and $1.0 million during the three months ended June 30, 2018 and 2017, respectively. For financial statement purposes, revenue-related taxes are included in "Operating and administrative expenses" on the Condensed Consolidated Statements of Income (but are excluded from Electric Utility operating expenses presented above).

(c) 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 June 30, 2018, were 5.1% colder than normal and 33.3% colder than during the three months ended June 30, 2017. The colder weather occurred during the month of April, which was 33.6% colder than normal. Gas Utility core market volumes increased 2.7 bcf (31.0%) principally reflecting the effects of the colder weather and growth in the number of core market customers. Total Gas Utility distribution system throughput increased 7.2 bcf principally reflecting higher large firm and interruptible delivery service volumes and higher core market volumes. Electric Utility kilowatt-hour sales were 5.8% higher than the prior-year period principally reflecting the impact of the colder weather on Electric Utility heating-related sales.

UGI Utilities revenues increased $13.3 million reflecting a $10.8 million increase in Gas Utility revenues and higher Electric Utility revenues. In accordance with a PUC Order issued May 17, 2018, Gas Utility's revenues were reduced by $22.7 million, and an associated regulatory liability established, to record tax savings that accrued during the period January 1, 2018 to June 30, 2018 as a result of the TCJA. Excluding the impact of this reduction in revenues, Gas Utility revenues increased $33.5 million principally reflecting an increase in core market revenues ($27.1 million) and higher large firm delivery service revenues ($5.9 million).

The $27.1 million increase in Gas Utility core market revenues reflects the effects of the higher core market throughput ($19.5 million), higher average retail core market PGC rates ($6.5 million) and the increase in PNG base rates effective October 20, 2017 ($1.1 million). The increase in Electric Utility revenues principally reflects the higher distribution system sales and slightly higher average DS rates ($2.3 million). UGI Utilities cost of sales was $72.5 million in the three months ended June 30, 2018 compared with $52.0 million in the three months ended June 30, 2017, principally reflecting higher Gas Utility cost of sales ($18.7 million) and higher Electric Utility cost of sales ($1.9 million) from higher distribution system sales and the slightly higher DS rates. The higher Gas Utility cost of sales reflects higher retail core-market volumes ($9.8 million), higher average retail core-market PGC rates ($6.5 million) and, to a lesser extent, higher large firm delivery service cost of sales.

UGI Utilities total margin decreased $7.3 million reflecting the impact of the $22.7 million reduction in revenues resulting from the previously mentioned PUC Order. Excluding this reduction, UGI Utilities total margin increased $15.4 million principally reflecting higher total margin from Gas Utility core market customers ($11.0 million) and higher large firm delivery service total margin ($3.1 million). The increase in Gas Utility core market margin reflects, among other things, the higher core market throughput ($10.1 million) and the increase in PNG base rates effective October 20, 2017 ($0.9 million). Electric Utility total margin increased slightly principally reflecting the higher distribution volumes sold.

UGI Utilities operating income decreased $23.8 million, principally reflecting the decrease in total margin ($7.3 million), higher Gas Utility and Electric Utility operating and administrative expenses ($6.9 million), greater depreciation and amortization expense ($3.5 million), and lower other operating income ($6.1 million). The increase in UGI Utilities operating and administrative expenses principally reflects higher general and administrative costs including an increase in information technology ("IT") maintenance and consulting expenses ($2.4 million), higher distribution system expenses ($1.7 million), and higher uncollectible accounts expense ($1.5 million). The increase in depreciation and amortization expense reflects increased distribution system and IT capital expenditure activity. The decrease in other operating income principally reflects the absence of $5.8 million of income from an environmental insurance settlement recorded in the prior-year three-month period. UGI Utilities income before income taxes decreased $23.6 million reflecting the decrease in UGI Utilities operating income.

Interest Expense and Income Taxes

Interest expense in the 2018 three-month period was approximately equal to the prior-year period. The lower statutory income tax rate resulting from the TCJA did not have a material impact on our consolidated income tax benefit for the three months ended June 30, 2018.

As more fully described in Notes 5 and 6 to condensed consolidated financial statements, on May 17, 2018, the PUC issued an Order requiring Pennsylvania utilities, including UGI Gas, CPG and PNG, to establish a regulatory liability for tax benefits that accrued during the period beginning January 1, 2018 through June 30, 2018, resulting from the reduced federal tax rate under the TCJA. During the three months ended June 30, 2018, UGI Utilities reduced its combined utility revenues by $22.7 million, and recorded a regulatory liability in an equal amount, to reflect (1) $16.2 million of tax benefits accrued during the period January 1 to June 30, 2018, plus (2) $6.5 million of tax benefits expected to be generated by the future amortization of the regulatory liability. Approximately $14.9 million of the previously mentioned $16.2 million of tax benefits accrued relate to the period January 1, 2018 to March 31, 2018.

2018 nine-month period compared with the 2017 nine-month period

Nine Months Ended June 30,	2018	2017	Increase (Decrease)	
(Dollars in millions)				
Gas Utility:				
Revenues (a)	$ 894.5	$ 700.8	$ 193.7	27.6 %
Total margin (a)(b)	$ 453.8	$ 412.3	$ 41.5	10.1 %
Operating and administrative expenses	$ 166.0	$ 150.8	$ 15.2	10.1 %
Operating income	$ 230.5	$ 219.7	$ 10.8	4.9 %
Income before income taxes	$ 199.3	$ 190.7	$ 8.6	4.5 %
System throughput — bcf				
Core market	75.8	65.4	10.4	15.9 %
Total	210.2	194.6	15.6	8.0 %
Heating degree days — % (warmer) than normal (c)	(1.3)%	(11.3)%	—	—
Electric Utility:				
Revenues	$ 71.8	$ 67.2	$ 4.6	6.8 %
Total margin (b)	$ 27.2	$ 26.3	$ 0.9	3.4 %
Operating and administrative expenses (b)	$ 18.3	$ 16.2	$ 2.1	13.0 %
Operating income	$ 4.9	$ 6.6	$ (1.7)	(25.8)%
Income before income taxes	$ 4.0	$ 5.2	$ (1.2)	(23.1)%
Distribution sales — gwh	747.0	710.5	36.5	5.1 %

(a) In accordance with a PUC Order issued May 17, 2018, Gas Utility's revenues and total margin for the nine months ended June 30, 2018, were reduced by $24.1 million to record a regulatory liability related to tax savings for the period January 1, 2018 to June 30, 2018 as a result of the TCJA (see Notes 5 and 6 to condensed consolidated financial statements).

(b) 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 $3.7 million and $3.5 million during each of the nine months ended June 30, 2018 and 2017, respectively. For financial statement purposes, revenue-related taxes are included in "Operating and administrative expenses" on the Condensed Consolidated Statements of Income (but are excluded from Electric Utility operating expenses presented above).

(c) 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 nine months ended June 30, 2018, were 1.3% warmer than normal but 11.3% colder than during the nine months ended June 30, 2017. Gas Utility core market volumes increased 10.4 bcf (15.9%) reflecting, among other things, the effects of the colder weather and growth in the number of core market customers. Total Gas Utility distribution system throughput increased 15.6 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 5.1% higher than the prior-year period, principally reflecting the impact of the colder weather on Electric Utility heating-related sales.

UGI Utilities revenues increased $198.3 million reflecting a $193.7 million increase in Gas Utility revenues and higher Electric Utility revenues. In accordance with a PUC Order issued May 17, 2018, during the 2018 nine-month period Gas Utility's revenues were reduced by $24.1 million, and an associated regulatory liability established, to record tax savings that accrued during the period January 1, 2018 to June 30, 2018 as a result of the TCJA. Excluding the impact of this reduction in revenues, Gas Utility revenues increased $217.8 million principally reflecting an increase in core market revenues ($148.4 million), higher off-system sales revenues ($52.7 million), and higher large firm delivery service revenues ($17.6 million).

The $148.4 million increase in Gas Utility core market revenues principally reflects the effects of the higher core market throughput ($72.1 million), higher average retail core market PGC rates ($64.3 million) and the increase in PNG base rates effective October 20, 2017 ($12.0 million). The increase in Electric Utility revenues principally reflects higher Electric Utility distribution system sales ($4.9 million). UGI Utilities cost of sales was $481.6 million in the nine months ended June 30, 2018 compared with $326.0 million in the nine months ended June 30, 2017, principally reflecting higher Gas Utility cost of sales ($152.1 million) and higher Electric Utility cost of sales ($3.5 million) reflecting the higher electricity sales. The higher Gas Utility cost of sales principally reflects higher average retail core market PGC rates ($64.3 million), higher cost of sales associated with Gas Utility off-system sales ($52.7 million), and higher retail core-market volumes ($37.0 million).

UGI Utilities total margin increased $42.4 million principally reflecting higher total margin from Gas Utility core market customers ($53.3 million) and higher large firm delivery service total margin ($11.0 million) partially offset by the previously mentioned impact of a $24.1 million reduction in revenues resulting from the previously mentioned PUC Order. The increase in Gas Utility core market margin principally reflects the higher core market throughput ($42.7 million) and the increase in PNG base rates effective October 20, 2017 ($10.6 million). Electric Utility total margin increased $0.9 million principally reflecting the higher distribution system sales.

UGI Utilities operating income increased $9.0 million, principally reflecting the increase in total margin ($42.4 million) partially offset by higher operating and administrative expenses ($17.3 million), greater depreciation and amortization expense ($9.9 million) associated with increased distribution system and IT capital expenditure activity, and lower other operating income ($6.2 million). The increase in UGI Utilities operating and administrative expenses principally reflects higher uncollectible accounts expense ($8.5 million), higher contractor and outside services expenses ($4.3 million), higher compensation and benefits expenses ($3.5 million) and higher IT maintenance and consulting expenses ($3.2 million). The decrease in other operating income principally reflects the absence of $5.8 million of income from an environmental insurance settlement recorded in the prior-year nine-month period. UGI Utilities income before income taxes increased $7.5 million reflecting the increase in UGI Utilities operating income ($9.0 million) partially offset by slightly higher interest expense.

Interest Expense and Income Taxes

Interest expense in the 2018 nine-month period increased $1.6 million primarily reflecting higher short-term debt interest expense and interest on higher average long-term debt outstanding. Our consolidated income taxes for the nine months ended June 30, 2018, were impacted by the enactment of the TCJA. As previously mentioned, we are subject to a blended federal tax rate of 24.5% for Fiscal 2018. 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 $9.3 million for the nine months ended June 30, 2018. In addition to the adjustment to our federal deferred income tax balances, our income taxes for the nine months ended June 30, 2018, were further reduced by approximately $24.1 million principally reflecting the impact of the lower Fiscal 2018 income tax rate and, to a much lesser extent, the amortization of the excess deferred federal income taxes.

As more fully described in Notes 5 and 6 to condensed consolidated financial statements, on May 17, 2018, the PUC issued an Order requiring Pennsylvania utilities, including UGI Gas, CPG and PNG, to establish a regulatory liability for tax benefits that accrued during the period beginning January 1, 2018 through June 30, 2018, resulting from the reduced federal tax rate as a result of the TCJA. During the nine months ended June 30, 2018, UGI Utilities reduced its combined utility revenues by $24.1 million, and recorded a regulatory liability in an equal amount, to reflect (1) $17.1 million of tax benefits accrued during the period January 1 to June 30, 2018, plus (2) $7.0 million of additional tax benefits expected to be generated by the future amortization of the regulatory liability.

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 June 30, 2018, totaled $23.2 million compared to $5.2 million at September 30, 2017.

UGI Utilities' total debt outstanding at June 30, 2018, was $959.0 million, which includes $118.5 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 June 30, 2018, comprises $675.0 million of Senior Notes, an unsecured term loan of $121.9 million, and $40.0 million of Medium-Term Notes, and is net of $4.2 million of unamortized debt issuance costs.

On October 31, 2017, UGI Utilities entered into a $125.0 million unsecured variable-rate term loan agreement (the "Term Loan") with a group of banks. Proceeds from the Term Loan were used to repay revolving credit agreement borrowings and for general corporate purposes. The Term Loan is payable in equal quarterly installments of $1.6 million, commencing March 2018, with the balance of the principal being due and payable in full on October 30, 2022. 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. In July 2018, UGI Utilities entered into pay-fixed, receive-variable interest rate swap that generally fixes the underlying prevailing market interest rates on Term Loan borrowings at 3.00% through July 2022. This forward-starting interest rate swap commences September 30, 2019. We have designated this forward-starting interest rate swap as a cash flow hedge.

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 June 30, 2018, UGI Utilities’ available borrowing capacity under the UGI Utilities Credit Agreement was $179.5 million. During the 2018 and 2017 nine-month periods, average daily short-term borrowings under the UGI Utilities Credit Agreement were $150.0 million and $74.5 million, respectively, and peak short-term borrowings totaled $215.0 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 provided by operating activities was $255.6 million in the 2018 nine-month period compared to cash provided by operating activities of $236.6 million in the prior-year period. Cash flow from operating activities before changes in operating working capital was $250.3 million in the 2018 nine-month period compared to $241.9 million recorded in the prior-year period. The higher cash flow from operating activities before changes in operating working capital in the 2018 nine-month period largely reflects the increase in operating results in the 2018 nine-month period. Changes in operating working capital provided $5.3 million of operating cash flow during the 2018 nine-month period compared to $5.3 million of cash used for changes in working capital during the prior-year period. The higher cash provided in the 2018 nine-month period reflects, among other things, the effects of higher Gas Utility deferred fuel net overcollections during the current-year period offset in large part by higher cash used to fund changes in accounts receivable. The increase in cash used to fund changes in accounts receivable primarily reflects the higher Gas Utility distribution volumes and higher natural gas prices.

Investing activities. Cash used by investing activities was $221.3 million in the 2018 nine-month period compared to $211.6 million in the 2017 nine-month period. Total cash capital expenditures were $217.9 million in the 2018 nine-month period compared with $201.9 million recorded in the prior-year period. The increase in cash capital expenditures during the 2018 nine-month period principally reflects expenditures relating to a new headquarters building and higher new business capital expenditures, partially offset by lower IT capital expenditures.

Financing activities. Cash used by financing activities was $16.3 million in the 2018 nine-month period compared with $23.0 million during the 2017 nine-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 2018 nine-month period and used the net proceeds principally to reduce revolving credit balances and for general corporate purposes. During the 2018 nine-month period, UGI Utilities repaid $40 million of maturing Medium-Term Notes and $3.1 million of Term Loan debt. The 2018 nine-month period reflects net credit agreement repayments of $51.5 million compared with net repayments of $62.5 million during the prior-year period. Cash dividends paid during the 2018 nine-month period totaled $45.0 million compared to cash dividends paid of $40.0 million during 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, in December 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 enactment. Because a significant amount of the reduction relates to our regulated utility plant assets, most of the reduction to our deferred income taxes is not being recognized immediately in income tax expense. We have recorded a regulatory liability associated with the excess deferred federal income taxes related to our regulated utility plant assets which is being amortized to income tax expense over the remaining lives of the assets that gave rise to the excess deferred income taxes. The amount of the reduction in our net deferred income tax liabilities resulting from the TCJA that reduced income tax expense totaled $1.1 million and $9.3 million for the three and nine months ended June 30, 2018, respectively.

In addition to the adjustments to our net deferred income tax liabilities that reduced our income tax expense as noted above, our income taxes for the three and nine months ended June 30, 2018, were further reduced by approximately $0.8 million and $24.1 million, respectively. These reductions principally reflect the impact of the lower blended income tax rate of 24.5% and, to a much lesser extent, the amortization of the excess deferred federal income taxes.

On May 17, 2018, the PUC issued an Order requiring Pennsylvania utilities, including UGI Gas, CPG and PNG, to establish a regulatory liability for tax benefits that accrued during the period beginning January 1, 2018 through June 30, 2018, resulting from the reduced federal tax rate as a result of the TCJA. During the nine months ended June 30, 2018, UGI Utilities reduced its combined utility revenues by $24.1 million, and recorded a regulatory liability in an equal amount, to reflect (1) $17.1 million of tax benefits accrued during the period January 1 to June 30, 2018, plus (2) $7.0 million of tax benefits expected to be generated by the future amortization of the regulatory liability.

For further information on the impacts of U.S. tax reform, see Note 5 and Note 6 to the condensed consolidated financial statements.

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, which was later reduced by the Company to $7.7 million to reflect the impact of the TCJA and other adjustments. 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. The PUC entered an Order dated March 1, 2018, suspending the effective date for the rate increase to allow for investigation and public hearings in a review process that is expected to last up to nine months from the date of filing. The matter is currently pending before two PUC administrative law judges who are expected to issue a recommended decision that will be the subject of a final decision by the PUC. Although the Company expects to receive a final decision from the PUC in October 2018, 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. PNG's DSIC has been reset to zero as a result of its most recent base 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 most 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 began recovering revenue under the mechanism effective July 1, 2018, for the amount of DSIC-eligible plant placed into service as it exceeded the threshold amount of DSIC-eligible plant agreed upon in the settlement of its recent base rate case during the third quarter of Fiscal 2018.

Utilities Merger Request. On March 8, 2018 and March 13, 2018, the Company filed merger authorization requests with the PUC and MD PSC, respectively, to merge PNG and CPG into UGI Utilities, with a targeted effective date of October 1, 2018. There are no expected changes to annual base distribution rates for the combined utilities or to existing regulatory assets and liabilities as a result of the proposed merger. On July 20, 2018, the Company filed a Joint Petition for Settlement among the parties to the proceeding for approval by two administrative law judges by recommended decision that will be the subject of a final decision by the PUC. On July 25, 2018, the MD PSC issued an order approving the Company's merger request. The Company cannot predict the timing or the ultimate outcome of the PUC review of the merger request. On August 3, 2018, FERC approved requests made by CPG, PNG, and UGI Utilities in May 2018 relating to the transfer of certain FERC authorizations from PNG and CPG to UGI Utilities, to ensure continuity of certain interstate gas transportation services currently conducted by CPG and PNG after the effective date of the proposed merger. With the receipt of these FERC approvals, the approval of an application to transfer CPG's service territory designation to UGI Utilities remains the only FERC approval yet to be received in connection with the proposed merger.

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 June 30, 2018, the fair values of our natural gas futures and option contracts were not material.

Electric Utility's DS tariffs contain clauses which permit recovery of all prudently incurred power costs, including the cost of financial instruments used to hedge electricity costs, through the application of DS rates. Because of this ratemaking mechanism, there is limited power cost risk, including the cost of FTRs and forward electricity purchase contracts, associated with our Electric Utility operations. At June 30, 2018, all of our Electric Utility's forward electricity purchase contracts were subject to the NPNS exception. At June 30, 2018, Electric Utility did not have any FTR contracts.

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 June 30, 2018 were not material.

Interest Rate Risk

Our variable-rate debt at June 30, 2018, 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 June 30, 2018, combined borrowings outstanding under these variable-rate debt agreements totaled $240.4 million.

As previously mentioned, in October 2017, UGI Utilities entered into the $125 million variable rate Term Loan. 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. In July 2018, UGI Utilities entered into pay-fixed, receive-variable interest rate swap that generally fixes the underlying prevailing market interest rates on Term Loan borrowings at 3.00% through July 2022. This forward-starting interest rate swap commences September 30, 2019. We have designated this forward-starting interest rate swap as a cash flow hedge.

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 June 30, 2018.

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 June 30, 2018, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.2	Certification by the Chief Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2018, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32	Certification by the Chief Executive Officer and the Chief Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2018, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	XBRL Instance			
101.SCH	XBRL Taxonomy Extension Schema			
101.CAL	XBRL Taxonomy Extension Calculation Linkbase			
101.DEF	XBRL Taxonomy Extension Definition Linkbase			
101.LAB	XBRL Taxonomy Extension Labels Linkbase			
101.PRE	XBRL Taxonomy Extension Presentation Linkbase			

UGI UTILITIES, INC. AND SUBSIDIARIES

EXHIBIT INDEX

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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: August 7, 2018	By:	/s/ Daniel J. Platt
		Daniel J. Platt Vice President - Finance and Chief Financial Officer
Date: August 7, 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)

	Nine Months Ended June 30,	Year Ended September 30,			
	2018	2017	2016	2015	2014
Earnings:					
Earnings before income taxes	$ 203,303	$ 188,095	$ 163,271	$ 200,539	$ 207,929
Interest expense	31,688	39,831	37,285	40,400	37,897
Amortization of debt discount and expense	345	381	345	728	575
Estimated interest component of rental expense	1,357	2,373	2,512	2,728	2,398
	$ 236,693	$ 230,680	$ 203,413	$ 244,395	$ 248,799
Fixed Charges:					
Interest expense	$ 31,688	$ 39,831	$ 37,285	$ 40,400	$ 37,897
Amortization of debt discount and expense	345	381	345	728	575
Allowance for funds used during construction (capitalized interest)	1,673	1,608	602	407	227
Estimated interest component of rental expense	1,357	2,373	2,512	2,728	2,398
	$ 35,063	$ 44,193	$ 40,744	$ 44,263	$ 41,097
Ratio of earnings to fixed charges	6.75	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: August 7, 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: August 7, 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 June 30, 2018 (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: August 7, 2018	Date: August 7, 2018