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, 2016

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.)

UGI UTILITIES, INC.
2525 N. 12th Street, Suite 360
Reading, PA
(Address of principal executive offices)
19612
(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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ☑	Smaller reporting company o

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, 2016, 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

TABLE OF CONTENTS

UGI UTILITIES, INC. AND SUBSIDIARIES

PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2016	September 30, 2015	June 30, 2015
ASSETS			
Current assets:			
Cash and cash equivalents	$ 82,449	$ 3,099	$ 16,522
Restricted cash	212	6,602	3,683
Accounts receivable (less allowances for doubtful accounts of $7,921, $5,599 and $12,534, respectively)	59,301	55,659	89,340
Accounts receivable — related parties	638	1,271	2,039
Accrued utility revenues	10,099	12,051	7,716
Inventories	27,009	51,716	33,376
Deferred income taxes	—	24,694	29,904
Income taxes receivable	—	10,026	—
Regulatory assets	3,263	4,105	2,763
Derivative instruments	5,384	934	1,285
Prepaid expenses & other current assets	33,724	23,903	13,551
Total current assets	222,079	194,060	200,179
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $961,006, $929,130 and $918,311, respectively)	1,945,539	1,824,369	1,781,668
Goodwill	182,145	182,145	182,145
Regulatory assets	342,037	300,103	251,479
Derivative instruments	109	—	111
Other assets	7,989	7,501	7,623
Total assets	$ 2,699,898	$ 2,508,178	$ 2,423,205
LIABILITIES AND STOCKHOLDER’S EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 20,000	$ 247,000	$ 72,000
Short-term borrowings	130,000	71,700	2,700
Accounts payable	50,665	58,135	44,687
Accounts payable — related parties	5,838	4,430	5,477
Regulatory liability — deferred fuel and power refunds	34,432	36,638	45,564
Derivative instruments	507	12,591	4,412
Other current liabilities	113,011	103,265	151,760
Total current liabilities	354,453	533,759	326,600
Long-term debt	630,000	375,000	550,000
Deferred income taxes	545,614	512,497	478,108
Deferred investment tax credits	3,348	3,597	3,681
Pension and postretirement benefit obligations	128,932	135,003	91,804
Other noncurrent liabilities	98,652	57,702	50,752
Total liabilities	1,760,999	1,617,558	1,500,945
Commitments and contingencies (Note 7)			
Common stockholder’s equity:			
Common Stock, $2.25 par value (authorized — 40,000,000 shares; issued and outstanding — 26,781,785 shares)	60,259	60,259	60,259
Additional paid-in capital	473,295	471,904	471,796
Retained earnings	434,391	372,143	396,823
Accumulated other comprehensive loss	(29,046)	(13,686)	(6,618)
Total common stockholder’s equity	938,899	890,620	922,260
Total liabilities and stockholder’s equity	$ 2,699,898	$ 2,508,178	$ 2,423,205

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,	
	2016	2015	2016	2015
Revenues	$ 140,283	$ 143,490	$ 660,312	$ 931,369
Costs and expenses:				
Cost of sales — gas, fuel and purchased power (excluding depreciation shown below)	44,415	53,691	257,288	475,079
Operating and administrative expenses	43,254	51,393	136,406	156,858
Operating and administrative expenses — related parties	2,811	2,647	8,789	9,567
Taxes other than income taxes	3,970	3,706	12,187	12,613
Depreciation	15,877	14,985	47,850	44,300
Amortization	673	928	2,431	2,682
Other operating (income) loss, net	(532)	(4,044)	2,769	(8,253)
	110,468	123,306	467,720	692,846
Operating income	29,815	20,184	192,592	238,523
Interest expense	9,158	9,985	27,922	31,245
Income before income taxes	20,657	10,199	164,670	207,278
Income taxes	8,054	2,892	65,422	81,543
Net income	$ 12,603	$ 7,307	$ 99,248	$ 125,735

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,	
	2016	2015	2016	2015
Net income	$ 12,603	$ 7,307	$ 99,248	$ 125,735
Other comprehensive (loss) income:				
Net losses on derivative instruments (net of tax of $0, $0, $12,016 and $0, respectively)	—	—	(16,943)	—
Reclassifications of net losses on derivative instruments (net of tax of $(253), $(277), $(782) and $(833), respectively)	357	392	1,103	1,175
Benefit plans reclassifications of actuarial losses and prior service costs (net of tax of $(113), $(92), $(340) and $(275), respectively)	160	128	480	388
Other comprehensive income (loss)	517	520	(15,360)	1,563
Comprehensive income	$ 13,120	$ 7,827	$ 83,888	$ 127,298

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, 2016	Nine Months Ended June 30, 2015
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 99,248	$ 125,735
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	50,281	46,982
Deferred income tax expense (benefit)	66,136	(10,417)
Provision for uncollectible accounts	6,716	10,997
Settlement of interest rate protection agreements	(35,975)	—
Other, net	954	526
Net change in:		
Accounts receivable and accrued utility revenues	(9,864)	(27,817)
Inventories	24,707	61,843
Deferred fuel and power costs, net of changes in unsettled derivatives	(11,587)	59,397
Accounts payable	(6,062)	(14,884)
Other current assets	(7,833)	631
Other current liabilities	17,763	47,939
Net cash provided by operating activities	194,484	300,932
CASH FLOWS FROM INVESTING ACTIVITIES		
Expenditures for property, plant and equipment	(163,967)	(141,884)
Net costs of property, plant and equipment disposals	(7,664)	(6,358)
Decrease (increase) in restricted cash	6,390	(91)
Net cash used by investing activities	(165,241)	(148,333)
CASH FLOWS FROM FINANCING ACTIVITIES		
Payment of dividends	(37,000)	(45,600)
Issuances of long-term debt	99,415	—
Repayments of long-term debt	(72,000)	(20,000)
Increase (decrease) in short-term borrowings	58,300	(83,600)
Other	1,392	722
Net cash provided (used) by financing activities	50,107	(148,478)
Cash and cash equivalents increase	$ 79,350	$ 4,121
CASH AND CASH EQUIVALENTS		
End of period	$ 82,449	$ 16,522
Beginning of period	3,099	12,401
Increase	$ 79,350	$ 4,121

See accompanying notes to condensed consolidated financial statements.

UGI UTILITIES, INC. AND SUBSIDIARIES

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

Note 1 — Nature of Operations

UGI Utilities, Inc. ("UGI Utilities"), a wholly owned subsidiary of UGI Corporation ("UGI"), and UGI Utilities' wholly owned subsidiaries UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc. ("CPG"), own and operate natural gas distribution utilities in eastern, northeastern and central Pennsylvania and in a portion of one Maryland county. UGI Utilities also owns and operates an electric distribution utility in northeastern Pennsylvania ("Electric Utility"). UGI Utilities' natural gas distribution utility is referred to as "UGI Gas." UGI Gas, PNG and CPG are collectively referred to as "Gas Utility." Gas Utility is subject to regulation by the Pennsylvania Public Utility Commission ("PUC") and, with respect to a small service territory in one Maryland county, the Maryland Public Service Commission, and Electric Utility is subject to regulation by the PUC. Gas Utility and Electric Utility are collectively referred to as "Utilities." Prior to June 1, 2015, PNG also had a heating, ventilation and air-conditioning service business which operated principally in the PNG service territory ("PNG HVAC Business"). The assets of the PNG HVAC Business principally comprising customer contracts were sold on June 1, 2015.

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

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation. Our condensed consolidated financial statements include the accounts of UGI Utilities and its subsidiaries (collectively, "we" or the "Company"). We eliminate all significant 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, 2015, 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, 2015 ("the Company's 2015 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 in the Condensed Consolidated Balance Sheets at their fair values, unless the derivative instruments qualify for the normal purchase and normal sale ("NPNS") exception under GAAP and such exception has been elected. The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is subject to regulatory ratemaking mechanisms or is designated and qualifies for hedge accounting.

Gains and losses on substantially all of the derivative instruments used by Gas Utility and Electric Utility (for which NPNS has not been elected) to hedge commodity prices are included in regulatory assets and liabilities in accordance with GAAP regarding accounting for rate-regulated entities. Certain of our derivative instruments are designated and qualify as cash flow hedges. For cash flow hedges, changes in the fair value of the derivative financial instruments are recorded in accumulated other comprehensive income (loss) ("AOCI"), to the extent effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. We discontinue cash flow hedge accounting if the occurrence of the forecasted transaction is determined to be no longer probable. Hedge accounting is also discontinued for derivatives that cease to be highly effective. Certain other commodity derivative financial instruments, although generally effective as hedges, do not qualify for hedge accounting treatment. Changes in the fair values of these derivative instruments are reflected in net income. Cash flows from derivative financial instruments are included in cash flows from operating activities.

For a more detailed description of the derivative instruments we use, our accounting for derivatives, our objectives for using them and other information, see Note 10.

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

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

Use of Estimates. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and costs. These estimates are based on management's knowledge of current events, historical experience and various other assumptions that are believed to be reasonable under the circumstances. Accordingly, actual results may be different from these estimates and assumptions.

Note 3 — Accounting Changes

Adoption of New Accounting Standard

Presentation of Deferred Taxes. During the first quarter of Fiscal 2016, the Company adopted new accounting guidance regarding the classification of deferred taxes. The new guidance amends existing guidance to require that deferred income tax liabilities and assets be classified as noncurrent in a classified balance sheet, and eliminates the prior guidance which required an entity to separate deferred tax liabilities and assets into a current amount and a noncurrent amount in a classified balance sheet. We applied this guidance prospectively and, as such, the September 30, 2015 and June 30, 2015 Condensed Consolidated Balance Sheets included herein have not been adjusted.

Accounting Standards Not Yet Adopted

Share-Based Payments. In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-09, "Improvements to Employee Share-Based Payment Accounting." This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The amendments in this ASU are effective for interim and annual periods beginning after December 15, 2016 (Fiscal 2018). Early adoption is permitted. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance.

Leases. In February 2016, the FASB issued ASU No. 2016-02, "Leases." This ASU amends existing guidance to require entities that lease assets to recognize the assets and liabilities for the rights and obligations created by those leases on the balance sheet. The new guidance also requires additional disclosures about the amount, timing and uncertainty of cash flows from leases. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2018 (Fiscal 2020). Early adoption is permitted. Lessees must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance but anticipates an increase in the recognition of right-of-use assets and lease liabilities.

Debt Issuance Costs. In April 2015, the FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs." This ASU amends existing guidance to require the presentation of debt issuance costs in the balance sheet as a direct deduction from the carrying amount of the related debt liability instead of a deferred charge. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2015 (Fiscal 2017). Early adoption is permitted. Entities will apply the new guidance retrospectively to all periods presented. The Company expects to adopt the new guidance effective September 30, 2016. The adoption of the new guidance is not expected to have a material impact on the Company's financial statements.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers." The guidance provided under this ASU, as amended, supersedes the revenue recognition requirements in Accounting Standards Codification ("ASC") No. 605, "Revenue Recognition," and most industry-specific guidance included in the ASC. The standard requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new guidance is effective for the Company for interim and annual periods beginning after December 15, 2017 (Fiscal 2019) and allows for either full retrospective adoption or modified retrospective adoption. We have not yet selected a transition method and are currently evaluating the impact of adopting this guidance on our consolidated financial statements.

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

Note 4 — Inventories

Inventories comprise the following:

	June 30, 2016	September 30, 2015	June 30, 2015
Gas Utility natural gas	$ 13,561	$ 37,510	$ 19,205
Materials, supplies and other	13,448	14,206	14,171
Total inventories	$ 27,009	$ 51,716	$ 33,376

At June 30, 2016, UGI Utilities was a party to two principal storage contract administrative agreements (“SCAAs”) having terms of three years. One of the SCAAs was with UGI Energy Services, LLC (“Energy Services”), a second-tier, wholly owned subsidiary of UGI (see Note 12) and one of the SCAAs was with a non-affiliate. Pursuant to SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon commencement of the SCAAs, will receive a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the terms of the SCAAs. The historical cost of natural gas storage inventories released under the SCAAs, which represents a portion of Gas Utility’s total natural gas storage inventories, and any exchange receivable (representing amounts of natural gas inventories used by the other parties to the agreement but not yet replenished for which UGI Utilities has the rights), are included in the caption “Gas Utility natural gas” in the table above.

The carrying value of gas storage inventories released under the SCAAs at June 30, 2016, September 30, 2015 and June 30, 2015, comprising 4.6 billion cubic feet (“bcf”), 9.0 bcf and 4.5 bcf of natural gas, was $8,390, $22,694 and $11,337, respectively. At June 30, 2016, September 30, 2015 and June 30, 2015, UGI Utilities held a total of $15,100, $17,700 and $17,700, respectively, of security deposits from its SCAA counterparties. These amounts are included in other current liabilities on the Condensed Consolidated Balance Sheets.

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

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

Note 5 — Regulatory Assets and Liabilities and Regulatory Matters

For a description of the Company's regulatory assets and liabilities other than those described below, see Note 4 in the Company's 2015 Annual Report. UGI Utilities currently does not recover a rate of return on its regulatory assets. The following regulatory assets and liabilities associated with Gas Utility and Electric Utility are included in our accompanying Condensed Consolidated Balance Sheets:

	June 30, 2016	September 30, 2015	June 30, 2015
Regulatory assets:			
Income taxes recoverable	$ 119,604	$ 115,946	$ 111,807
Underfunded pension and postretirement plans	133,356	140,762	103,250
Environmental costs (a)	60,716	19,983	14,441
Removal costs, net	22,444	21,223	19,635
Other	9,180	6,294	5,109
Total regulatory assets	$ 345,300	$ 304,208	$ 254,242
Regulatory liabilities:			
Postretirement benefits	$ 19,671	$ 19,975	$ 19,687
Deferred fuel and power refunds	34,432	36,638	45,564
State tax benefits — distribution system repairs	14,604	13,266	10,894
Other	1,149	1,125	1,377
Total regulatory liabilities (b)	$ 69,856	$ 71,004	$ 77,522

(a) Environmental costs at June 30, 2016, include amounts probable of recovery recorded in conjunction with UGI Gas' Consent Order and Agreement with the Pennsylvania Department of Environmental Protection (see Note 7).
(b) Regulatory liabilities, other than deferred fuel and power refunds, are recorded in other current and other noncurrent liabilities in the Condensed Consolidated Balance Sheets.

Deferred fuel and power refunds. Gas Utility's and Electric Utility's tariffs contain clauses that permit recovery of all prudently incurred purchased gas and power costs through the application of purchased gas cost ("PGC") rates in the case of Gas Utility and default service ("DS") tariffs in the case of Electric Utility. The clauses provide for periodic adjustments to PGC and DS rates for differences between the total amount of purchased gas and electric generation supply costs collected from customers and recoverable costs incurred. Net undercollected costs are classified as a regulatory asset and net overcollections are classified as a regulatory liability.

Gas Utility uses derivative instruments to reduce volatility in the cost of gas it purchases for firm- residential, commercial and industrial ("retail core-market") customers. Realized and unrealized gains or losses on natural gas derivative instruments are included in deferred fuel costs or refunds. Net unrealized gains (losses) on such contracts at June 30, 2016, September 30, 2015, and June 30, 2015, were $5,483, $(3,262) and $(729), respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. For contracts entered into prior to March 1, 2015, we did not elect the NPNS exception under GAAP, and as a result, we recognize the fair value of these contracts on the balance sheet with an associated adjustment to regulatory assets or liabilities because Electric Utility is entitled to fully recover its DS costs. At September 30, 2015, and June 30, 2015, the fair values of Electric Utility's electricity supply contracts not subject to NPNS were (losses) of $(533) and $(1,428), respectively. These amounts are reflected in current derivative instrument liabilities on the Condensed Consolidated Balance Sheets with equal and offsetting amounts reflected in deferred fuel and power refunds in the table above. At June 30, 2016, all Electric Utility forward electricity purchase contracts were subject to the NPNS exception (see Note 10).

In order to reduce volatility associated with a substantial portion of its electric transmission congestion costs, Electric Utility obtains financial transmission rights ("FTRs"). FTRs are derivative instruments that entitle the holder to receive compensation for electricity transmission congestion charges when there is insufficient electricity transmission capacity on the electric transmission grid. Because Electric Utility is entitled to fully recover its DS costs, realized and unrealized gains or losses on FTRs are included in deferred fuel and power costs or deferred fuel and power refunds. Unrealized gains or losses on FTRs at June 30, 2016, September 30, 2015, and June 30, 2015, were not material.

Preliminary Stage Information Technology Costs. During the second quarter of Fiscal 2016, we determined that certain preliminary project stage costs associated with an ongoing information technology project at UGI Utilities were probable of future recovery in rates in accordance with GAAP related to regulated entities. As a result, during the second quarter of Fiscal 2016, we capitalized $5,830 of such project costs ($5,375 of which had been expensed prior to Fiscal 2016) and recorded associated increases to utility property, plant and equipment ($2,755) and regulatory assets ($3,075). Subsequently, we continue to capitalize such preliminary stage project costs in accordance with GAAP related to regulated entities.

UGI Gas Base Rate Filing. On January 19, 2016, UGI Utilities filed a rate request with the PUC to increase UGI Gas's annual base operating revenues for residential, commercial and industrial customers by $58,600. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. UGI Utilities requested that the new gas rates become effective March 19, 2016. The PUC entered an Order dated February 11, 2016, suspending the effective date for the rate increase to no later than October 19, 2016, to allow for investigation and public hearings. On June 30, 2016, a Joint Petition for Approval of Settlement of all issues supported by all active parties was filed with the PUC. Under the terms of the Joint Petition, UGI Utilities will be permitted, effective October 19, 2016, to increase UGI Gas' annual base distribution rates by $27,000. The Joint Petition is subject to receipt of a recommended decision by a PUC administrative law judge and an order of the PUC approving the settlement. The Company cannot predict the ultimate outcome of the rate case review process.

Distribution System Improvement Charge. On April 14, 2012, legislation became effective enabling gas and electric utilities in Pennsylvania, under certain circumstances, to recover the cost of eligible capital investment in distribution system infrastructure improvement projects between base rate cases. The charge enabled by the legislation is known as a distribution system improvement charge ("DSIC"). The primary benefit to a company from a DSIC charge is the elimination of regulatory lag, or delayed rate recognition, that occurs under traditional ratemaking relating to qualifying capital expenditures. To be eligible for a DSIC, a utility must have filed a general rate filing within five years of its petition seeking permission to include a DSIC in its tariff, and not exceed certain earnings tests. Absent PUC permission, the DSIC is capped at five percent of the amount billed to customers. PNG and CPG received PUC approval on a DSIC tariff, initially set at zero, in 2014, while UGI Gas had not had a general rate filing within the required time period to be eligible. PNG and CPG began charging a DSIC at a rate other than zero beginning on April 1, 2015 and April 1, 2016, respectively. In March 2016, PNG and CPG filed petitions, seeking approval to increase the maximum allowable DSIC from five percent to ten percent of billed distribution revenues. Also in March 2016, UGI Gas sought PUC approval to initiate a DSIC effective November 2017. To date, no action has been taken by the PUC on any of these petitions. The Company cannot predict the timing or outcome of these petitions. The impact of the DSIC charge at PNG and CPG did not have a material effect on Gas Utility results of operations.

Note 6 — Debt

In April 2016, UGI Utilities entered into a Note Purchase Agreement (the "2016 Note Purchase Agreement") which provides for the private placement of (1) $100,000 aggregate principal amount of 2.95% Senior Notes due June 30, 2026; (2) $200,000 aggregate principal amount of 4.12% Senior Notes due September 30, 2046; and (3) $100,000 aggregate principal amount of 4.12% Senior Notes due October 31, 2046 (collectively, the "Senior Notes"). On June 30 2016, UGI Utilities issued $100,000 aggregate principal amount of 2.95% Senior Notes pursuant to the 2016 Note Purchase Agreement. The net proceeds from the issuance of the 2.95% Senior Notes were used to repay short-term borrowings under UGI Utilities' Credit Agreement in early July 2016. The 4.12% Senior Notes due September 30, 2046 and the 4.12% Senior Notes due October 31, 2046 are expected to be issued in September 2016 and October 2016, respectively. The Senior Notes are unsecured and rank equally with UGI Utilities' existing outstanding senior debt. UGI Utilities expects to use the net proceeds from the issuance of the 4.12% Senior Notes to repay UGI Utilities' currently outstanding $175,000 principal amount of 5.75% Senior Notes due September 30, 2016 and for general corporate purposes. Because UGI Utilities has the intent and ability to refinance the 5.75% Senior Notes on a long-term basis, the 5.75% Senior Notes have been classified as long-term debt on the June 30, 2016, Condensed Consolidated Balance Sheet. The 2016 Note Purchase Agreement contains restrictive and financial covenants including a requirement that UGI Utilities not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.00.

Note 7 — Commitments and Contingencies

Contingencies

Environmental Matters

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

UGI Utilities and its subsidiaries have entered into agreements with the Pennsylvania Department of Environmental Protection ("DEP") to address the remediation of former MGPs in Pennsylvania. CPG is party to a Consent Order and Agreement ("CPG-COA") with the DEP requiring CPG to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which MGP related facilities were operated ("CPG MGP Properties") and to plug a minimum number of non-producing natural gas wells per year. In addition, PNG is a party to a Multi-Site Remediation Consent Order and Agreement ("PNG-COA") with the DEP. The PNG-COA requires PNG to perform annually a specified level of activities associated with environmental investigation and remediation work at certain properties on which MGP-related facilities were operated ("PNG MGP Properties"). Under these agreements, environmental expenditures relating to the CPG MGP Properties and the PNG MGP Properties are capped at $1,750 and $1,100, respectively, in any calendar year. The CPG-COA is scheduled to terminate at the end of 2018. The PNG-COA terminates in 2019 but may be terminated by either party effective at the end of any two-year period beginning with the original effective date in March 2004. At June 30, 2016 and 2015, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $12,247 and $9,595, respectively. CPG and PNG have recorded associated regulatory assets for these costs because recovery of these costs from customers is probable (see Note 5).

In May 2016, UGI Gas executed a Consent Order and Agreement ("UGI Gas-COA") with the DEP with an effective date of October 1, 2016. The UGI Gas-COA will terminate in September 2031 if not extended by the parties. The UGI Gas-COA requires UGI Gas to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which MGP related facilities were operated ("UGI Gas MGP Properties"). Under this agreement, required environmental expenditures related to the UGI Gas MGP Properties are capped at $2,500 in any calendar year. At June 30, 2016, our estimated accrued liabilities for environmental investigation and remediation costs related to the UGI Gas-COA totaled $43,759. UGI Gas has recorded associated regulatory assets for these costs because recovery of these costs from customers is probable (See Note 5).

UGI Utilities does not expect its costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to its results of operations because (1) UGI Gas is currently permitted to include in rates, through future base rate proceedings, a five-year average of such prudently incurred remediation costs, and (2) CPG and PNG receive ratemaking recognition of estimated environmental investigation and remediation costs associated with their environmental sites. This ratemaking recognition balances the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites. UGI Gas has proposed a similar environmental cost tracking mechanism that will address the costs incurred under the UGI Gas-COA.

From time to time, UGI Utilities is notified of sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by UGI Utilities or owned or operated by its former subsidiaries. Such parties generally investigate the extent of environmental contamination or perform environmental remediation. Management believes that under applicable law UGI Utilities should not be liable in those instances in which a former subsidiary owned or operated an MGP. There could be, however, significant future costs of an uncertain amount associated with environmental damage caused by MGPs outside Pennsylvania that UGI Utilities directly operated, or that were owned or operated by former subsidiaries of UGI Utilities if a court were to conclude that (1) the subsidiary's separate corporate form should be disregarded, or (2) UGI Utilities should be considered to have been an operator because of its conduct with respect to its subsidiary's MGP. At June 30, 2016, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas MGP sites outside of Pennsylvania was material for UGI Utilities.

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

Note 8 — Defined Benefit Pension and Other Postretirement Plans

We sponsor a defined benefit pension plan for employees hired prior to January 1, 2009, of UGI, UGI Utilities, PNG, CPG and certain of UGI's other domestic wholly owned subsidiaries ("Pension Plan"). Pension Plan benefits are based on years of service, age and employee compensation. We also provide postretirement health care benefits to certain retirees and postretirement life insurance benefits to nearly all active and retired employees.

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

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended June 30,	2016	2015	2016	2015
Service cost	$ 1,731	$ 1,741	$ 46	$ 48
Interest cost	5,818	5,628	116	119
Expected return on assets	(7,167)	(7,225)	(149)	(153)
Amortization of:				
Prior service cost (benefit)	87	87	(160)	(160)
Actuarial loss	2,393	2,199	24	32
Net benefit cost (income)	2,862	2,430	(123)	(114)
Change in associated regulatory liabilities	—	—	878	938
Net benefit cost after change in regulatory liabilities	$ 2,862	$ 2,430	$ 755	$ 824

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended June 30,	2016	2015	2016	2015
Service cost	$ 5,195	$ 5,222	$ 137	$ 145
Interest cost	17,453	16,883	349	356
Expected return on assets	(21,502)	(21,674)	(447)	(459)
Amortization of:				
Prior service cost (benefit)	261	261	(480)	(480)
Actuarial loss	7,179	6,595	73	95
Net benefit cost (income)	8,586	7,287	(368)	(343)
Change in associated regulatory liabilities	—	—	2,632	2,813
Net benefit cost after change in regulatory liabilities	$ 8,586	$ 7,287	$ 2,264	$ 2,470

Pension Plan assets are held in trust and consist principally of publicly traded, diversified equity and fixed income mutual funds and, to a much lesser extent, smallcap common stocks and UGI Common Stock. It is our general policy to fund amounts for Pension Plan benefits equal to at least the minimum contribution required by ERISA. During the nine months ended June 30, 2016 and 2015, the Company made contributions to the Pension Plan of $7,402 and $8,348, respectively. The Company expects to make additional discretionary cash contributions of approximately $2,500 to the Pension Plan during the remainder of Fiscal 2016.

UGI Utilities has established a Voluntary Employees' Beneficiary Association ("VEBA") trust to pay retiree health care and life insurance benefits by depositing into the VEBA the annual amount of postretirement benefits costs, if any, determined under GAAP. The difference between such amount and the amounts included in UGI Gas' and Electric Utility's rates is deferred for future recovery from, or refund to, ratepayers. There were no required contributions to the VEBA during the nine months ended June 30, 2016 and 2015.

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 9 — Fair Value Measurements

Derivative Instruments

The following table presents on a gross basis our derivative assets and liabilities including both current and noncurrent portions, that are measured at fair value on a recurring basis within the fair value hierarchy, as of June 30, 2016, September 30, 2015 and June 30, 2015:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
June 30, 2016:				
Assets:				
Commodity contracts	$ 5,715	$ 3	$ —	$ 5,718
Liabilities:				
Commodity contracts	$ (341)	$ (391)	$ —	$ (732)
September 30, 2015:				
Assets:				
Commodity contracts	$ 934	$ 373	$ —	$ 1,307
Liabilities:				
Commodity contracts	$ (4,560)	$ (1,388)	$ —	$ (5,948)
Interest rate contracts	$ —	$ (7,016)	$ —	$ (7,016)
June 30, 2015:				
Assets:				
Commodity contracts	$ 1,510	$ 469	$ —	$ 1,979
Liabilities:				
Commodity contracts	$ (2,390)	$ (2,605)	$ —	$ (4,995)

The fair values of our Level 1 exchange-traded commodity futures and option derivative contracts are based upon actively-quoted market prices for identical assets and liabilities. The fair values of the remainder of our derivative financial instruments and electricity forward contracts, which are designated as Level 2, are generally based upon recent market transactions and related market indicators. There were no transfers between Level 1 and Level 2 during the periods presented.

Other Financial Instruments

The carrying amounts of other financial instruments included in current assets and current liabilities (except for current maturities of long-term debt) approximate their fair values because of their short-term nature. The carrying amount and estimated fair value of our long-term debt (including current maturities) at June 30, 2016, were $650,000 and $747,588, respectively. The carrying amount and estimated fair value of our long-term debt (including current maturities) at June 30, 2015, were $622,000 and $683,521, respectively. We estimate the fair value of long-term debt by using current market rates and by discounting future cash flows using rates available for similar types of debt (Level 2).

Note 10 — Derivative Instruments and Hedging Activities

We are exposed to certain market risks related to our ongoing business operations. Management uses derivative financial and commodity instruments, among other things, to manage these risks. The primary risks managed by derivative instruments are (1) commodity price risk and (2) interest rate risk. Although we use derivative financial and commodity instruments to reduce market risk associated with forecasted transactions, we do not use derivative financial and commodity instruments for speculative or trading purposes. The use of derivative instruments is controlled by our risk management and credit policies, which govern, among other things, the derivative instruments we can use, counterparty credit limits and contract authorization limits. Because most of our commodity derivative instruments are generally subject to regulatory ratemaking mechanisms, we have limited commodity price risk associated with our Gas Utility or Electric Utility operations.

Commodity Price Risk

Gas Utility's tariffs contain clauses that permit recovery of all of the prudently incurred costs of natural gas it sells to retail core-market customers, including the cost of financial instruments used to hedge purchased gas costs. As permitted and agreed to by the PUC pursuant to Gas Utility's annual PGC filings, Gas Utility currently uses New York Mercantile Exchange ("NYMEX") natural gas futures and option contracts to reduce commodity price volatility associated with a portion of the natural gas it purchases for its retail core-market customers. At June 30, 2016 and 2015, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 13.4 million dekatherms and 13.1 million dekatherms, respectively. At June 30, 2016, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 15 months. Gains and losses on natural gas futures contracts and any gains on natural gas option contracts are recorded in regulatory assets or liabilities on the Condensed Consolidated Balance Sheets because it is probable such gains or losses will be recoverable from, or refundable to, customers through the PGC recovery mechanism (see Note 5).

Electric Utility's DS tariffs permit the recovery of all prudently incurred costs of electricity it sells to DS customers, including the cost of financial instruments used to hedge electricity costs. Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. For such contracts entered into prior to March 1, 2015, Electric Utility chose not to elect the NPNS exception under GAAP and the fair values of these contracts are reflected in current derivative instrument liabilities on the accompanying Condensed Consolidated Balance Sheets. Associated gains and losses on these forward contracts are recorded in regulatory assets and liabilities on the Condensed Consolidated Balance Sheets in accordance with GAAP because it is probable such gains or losses will be recoverable from, or refundable to, customers through the DS mechanism (see Note 5). Effective with Electric Utility forward electricity purchase contracts entered into beginning March 1, 2015, Electric Utility has elected the NPNS exception under GAAP and, as a result, the fair values of such contracts are not recognized on the balance sheet. At June 30, 2016, all of our Electric Utility's forward electricity purchase contracts were subject to the NPNS exception. At June 30, 2015, the volumes of Electric Utility's forward purchase contracts for which NPNS had not been elected was 494.5 million kilowatt hours.

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 in accordance with GAAP because it is probable such gains or losses will be recoverable from, or refundable to, customers through the DS mechanism (see Note 5). At June 30, 2016 and 2015, the total volumes associated with FTRs totaled 80.6 million kilowatt hours and 381.6 million kilowatt hours, respectively. At June 30, 2016, the maximum period over which we are economically hedging electricity congestion is 11 months.

In order to reduce operating expense volatility, UGI Utilities from time to time enters into NYMEX gasoline futures contracts for a portion of gasoline volumes expected to be used in the operation of its vehicles and equipment.

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. On March 31, 2016, concurrent with the pricing of the Senior Notes to be issued under the 2016 Note Purchase Agreement, UGI Utilities settled all of its then-existing IRPA contracts associated with such debt at a loss of $35,975. Because these IRPA contracts qualified for and were designated as cash flow hedges, the loss recognized in connection with the settled IRPAs has been recorded in AOCI and will be recognized in interest expense as the associated future interest expense impacts earnings. See Note 6 for additional information on the 2016 Note Purchase Agreement. As of June 30, 2016 and 2015, we had no unsettled IRPAs. At June 30, 2016, the amount of net losses associated with IRPAs expected to be reclassified into earnings during the next twelve months is $3,320.

Derivative Instrument Credit Risk

Our commodity exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2016 and 2015, restricted cash in brokerage accounts totaled $212 and $3,683, 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.

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

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, 2016 and 2015:

	June 30, 2016	June 30, 2015
Derivative assets:		
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	$ 5,718	$ 1,943
Derivatives not subject to PGC and DS mechanisms:		
Commodity contracts	—	36
Total derivative assets - gross	5,718	1,979
Gross amounts offset in the balance sheet	(225)	(583)
Total derivative assets - net	$ 5,493	$ 1,396
Derivative liabilities:		
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	$ (593)	$ (4,807)
Derivatives not subject to PGC and DS mechanisms:		
Commodity contracts	(139)	(188)
Total derivative liabilities - gross	(732)	(4,995)
Gross amounts offset in the balance sheet	225	583
Total derivative liabilities - net	$ (507)	$ (4,412)

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

Effect of Derivative Instruments

The following table provides information on the effects of derivative instruments not subject to ratemaking mechanisms on the Condensed Consolidated Statements of Income and changes in AOCI for the three and nine months ended June 30, 2016 and 2015:

	Loss Recognized in AOCI		Loss Reclassified from AOCI into Income		Location of Loss Reclassified from AOCI into Income
Three Months Ended June 30,	2016	2015	2016	2015	
Cash Flow Hedges:					
Interest rate contracts	$ —	$ —	$ (610)	$ (669)	Interest expense

	Gain Recognized in Income		Location of Gain Recognized in Income
Three Months Ended June 30,	2016	2015	
Derivatives Not Subject to PGC and DS Mechanisms:			
Gasoline contracts	$ 27	$ 111	Operating expenses/other operating income, net

	Loss Recognized in AOCI		Loss Reclassified from AOCI into Income		Location of Loss Reclassified from AOCI into Income
Nine Months Ended June 30,	2016	2015	2016	2015	
Cash Flow Hedges:					
Interest rate contracts	$ (28,959)	$ —	$ (1,885)	$ (2,008)	Interest expense

	Loss Recognized in Income		Location of Loss Recognized in Income
Nine Months Ended June 30,	2016	2015	
Derivatives Not Subject to PGC and DS Mechanisms:			
Gasoline contracts	$ (93)	$ (415)	Operating expenses/other operating income, net

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 normal purchase and normal sale exception accounting under GAAP because they provide for the delivery of products or services in quantities that are expected to be used in the normal course of operating our business and the price in the contract is based on an underlying that is directly associated with the price of the product or service being purchased or sold.

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

Note 11 — Accumulated Other Comprehensive Income

The tables below present changes in AOCI, net of tax, during the three and nine months ended June 30, 2016 and 2015:

	Postretirement Benefit Plans	Derivative Instruments	Total
Three Months Ended June 30, 2016			
AOCI - March 31, 2016	$ (8,956)	$ (20,607)	$ (29,563)
Reclassifications of benefit plan actuarial losses and prior service cost	160	—	160
Reclassifications of net losses on IRPAs	—	357	357
AOCI - June 30, 2016	$ (8,796)	$ (20,250)	$ (29,046)
Three Months Ended June 30, 2015			
AOCI - March 31, 2015	$ (6,051)	$ (1,087)	$ (7,138)
Reclassifications of benefit plan actuarial losses and prior service cost	128	—	128
Reclassifications of net losses on IRPAs	—	392	392
AOCI - June 30, 2015	$ (5,923)	$ (695)	$ (6,618)

	Postretirement Benefit Plans	Derivative Instruments	Total
Nine Months Ended June 30, 2016			
AOCI - September 30, 2015	$ (9,276)	$ (4,410)	$ (13,686)
Net losses on IRPAs	—	(16,943)	(16,943)
Reclassifications of benefit plan actuarial losses and prior service costs	480	—	480
Reclassifications of net losses on IRPAs	—	1,103	1,103
AOCI - June 30, 2016	$ (8,796)	$ (20,250)	$ (29,046)
Nine Months Ended June 30, 2015			
AOCI - September 30, 2014	$ (6,311)	$ (1,870)	$ (8,181)
Reclassifications of benefit plan actuarial losses and prior service costs	388	—	388
Reclassifications of net losses on IRPAs	—	1,175	1,175
AOCI - June 30, 2015	$ (5,923)	$ (695)	$ (6,618)

Note 12 — Related Party Transactions

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

From time to time, UGI Utilities is a party to SCAAs with Energy Services which have terms of up to three years. Under the SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts (subject to recall for operational purposes) to Energy Services for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon the commencement of the SCAAs, receives a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the term of the SCAAs. Energy Services, in turn, provides a firm delivery service and makes certain payments to UGI Utilities for its various obligations under the SCAAs. UGI Utilities incurred costs associated with Energy Services' SCAAs totaling $4,358 and $6,387 during the three and nine months ended June 30, 2016, respectively, and $5,691 and $10,898 during the three and nine months ended June 30, 2015, 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, were $8,100, $10,700, and $10,700 as of June 30, 2016, September 30, 2015 and June 30, 2015, respectively.

UGI Utilities reflects the historical cost of the gas storage inventories and any exchange receivable from Energy Services (representing amounts of natural gas inventories used but not yet replenished by Energy Services) on its balance sheet under the caption inventories. The carrying value of these gas storage inventories at June 30, 2016, September 30, 2015 and June 30, 2015, comprising approximately 2.7 bcf, 5.0 bcf and 2.6 bcf of natural gas, were $5,100, $12,889 and $6,809, respectively.

UGI Utilities has gas supply and delivery service agreements with Energy Services pursuant to which Energy Services provides certain gas supply and related delivery service to Gas Utility primarily during the heating season months of November through March. The aggregate amount of these transactions (exclusive of transactions pursuant to the SCAAs) during the three and nine months ended June 30, 2016, totaled $2,138 and $61,193, respectively. During the three and nine months ended June 30, 2015, such transactions totaled $2,380 and $45,413, respectively.

From time to time, the Company sells natural gas or pipeline capacity to Energy Services. During the three and nine months ended June 30, 2016, revenues associated with such sales to Energy Services totaled $4,514 and $26,134, respectively. During the three and nine months ended June 30, 2015, revenues associated with such sales to Energy Services totaled $9,129 and $71,546, respectively. Also from time to time, the Company purchases natural gas, pipeline capacity and electricity from Energy Services (in addition to those transactions already described above) and purchases a firm storage service from UGI Storage Company, a subsidiary of Energy Services, under one-year agreements. During the three and nine months ended June 30, 2016, such purchases totaled $6,928 and $30,032, respectively. During the three and nine months ended June 30, 2015, such purchases totaled $8,431 and $79,956, respectively.

Note 13 — Segment Information

We have determined that we have two reportable segments: (1) Gas Utility and (2) Electric Utility. Gas Utility revenues are derived principally from the sale and distribution of natural gas to customers in eastern, northeastern and central Pennsylvania. Electric Utility derives its revenues principally from the sale and distribution of electricity in two northeastern Pennsylvania counties. The PNG HVAC Business, prior to its sale in June 2015, did not meet the quantitative thresholds for separate segment reporting under GAAP relating to business segment reporting and has been included in "Other" below.

The accounting policies of our reportable segments are the same as those described in Note 2 of the Company's 2015 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)

Financial information by business segment follows:

Three Months Ended June 30, 2016:

		Reportable Segments	
	Total	Gas Utility	Electric Utility
Revenues	$ 140,283	$ 119,995	$ 20,288
Cost of sales	$ 44,415	$ 33,715	$ 10,700
Depreciation and amortization	$ 16,550	$ 15,339	$ 1,211
Operating income	$ 29,815	$ 27,116	$ 2,699
Interest expense	$ 9,158	$ 8,670	$ 488
Income before income taxes	$ 20,657	$ 18,446	$ 2,211
Capital expenditures (including the effects of accruals)	$ 56,481	$ 53,199	$ 3,282

Three Months Ended June 30, 2015:

		Reportable Segments		
	Total	Gas Utility	Electric Utility	Other
Revenues	$ 143,490	$ 119,412	$ 23,875	$ 203
Cost of sales	$ 53,691	$ 41,352	$ 12,339	$ —
Depreciation and amortization	$ 15,913	$ 14,786	$ 1,127	$ —
Operating income	$ 20,184	$ 15,099	$ 4,071	$ 1,014
Interest expense	$ 9,985	$ 9,483	$ 502	$ —
Income before income taxes	$ 10,199	$ 5,616	$ 3,569	$ 1,014
Capital expenditures (including the effects of accruals)	$ 43,315	$ 41,324	$ 1,991	$ —

Nine Months Ended June 30, 2016:

		Reportable Segments	
	Total	Gas Utility	Electric Utility
Revenues	$ 660,312	$ 595,025	$ 65,287
Cost of sales	$ 257,288	$ 221,646	$ 35,642
Depreciation and amortization	$ 50,281	$ 46,665	$ 3,616
Operating income	$ 192,592	$ 183,940	$ 8,652
Interest expense	$ 27,922	$ 26,583	$ 1,339
Income before income taxes	$ 164,670	$ 157,357	$ 7,313
Capital expenditures (including the effects of accruals)	$ 166,058	$ 158,472	$ 7,586
As of June 30, 2016			
Total assets (at period end)	$ 2,699,898	$ 2,534,039	$ 165,859
Goodwill (at period end)	$ 182,145	$ 182,145	$ —

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

Nine Months Ended June 30, 2015:

			Reportable Segments					
	Total		Gas Utility		Electric Utility		Other	
Revenues	$	931,369	$	847,890	$	82,621	$	858
Cost of sales	$	475,079	$	426,715	$	48,364	$	—
Depreciation and amortization	$	46,982	$	43,555	$	3,427	$	—
Operating income	$	238,523	$	226,248	$	11,300	$	975
Interest expense	$	31,245	$	29,717	$	1,528	$	—
Income before income taxes	$	207,278	$	196,531	$	9,772	$	975
Capital expenditures (including the effects of accruals)	$	139,624	$	134,018	$	5,606	$	—
As of June 30, 2015								
Total assets (at period end)	$	2,423,205	$	2,278,975	$	144,230	$	—
Goodwill (at period end)	$	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 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) large customer, counterparty or supplier defaults; (11) increased uncollectible accounts expense; (12) liability for personal injury and property damage arising from explosions and other catastrophic events, including acts of terrorism, resulting from operating hazards and risks incidental to generating and distributing electricity and transporting, storing and distributing natural gas, including liability in excess of insurance coverage; (13) political, regulatory and economic conditions in the United States; (14) capital market conditions, including reduced access to capital markets and interest rate fluctuations; and (15) changes in commodity market prices resulting in significantly higher cash collateral requirements.

These factors, and those factors set forth in Item 1A. Risk Factors in the Company's 2015 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, 2016 (“2016 three-month period”) with the three months ended June 30, 2015 (“2015 three-month period”) and the nine months ended June 30, 2016 (“2016 nine-month period”) with the nine months ended June 30, 2015 (“2015 nine-month period”). Our analyses of results of operations should be read in conjunction with the segment information included in Note 13 to the condensed consolidated financial statements.

2016 three-month period compared with 2015 three-month period

Three Months Ended June 30,	2016	2015	Increase (Decrease)	
(Dollars in millions)				
Gas Utility:				
Revenues	$ 120.0	$ 119.4	$ 0.6	0.5 %
Total margin (a)	$ 86.3	$ 78.1	$ 8.2	10.5 %
Operating and administrative expenses	$ 41.7	$ 48.6	$ (6.9)	(14.2)%
Operating income	$ 27.1	$ 15.1	$ 12.0	79.5 %
Income before income taxes	$ 18.4	$ 5.6	$ 12.8	228.6 %
System throughput — billions of cubic feet (“bcf”)				
Core market	10.3	8.9	1.4	15.7 %
Total	43.6	38.6	5.0	13.0 %
Heating degree days — % colder (warmer) than normal (b)	11.9%	(17.2)%	—	—
Electric Utility:				
Revenues	$ 20.3	$ 23.9	$ (3.6)	(15.1)%
Total margin (a)	$ 8.5	$ 10.3	$ (1.8)	(17.5)%
Operating and administrative expenses	$ 4.4	$ 5.1	$ (0.7)	(13.7)%
Operating income	$ 2.7	$ 4.1	$ (1.4)	(34.1)%
Income before income taxes	$ 2.2	$ 3.6	$ (1.4)	(38.9)%
Distribution sales — millions of kilowatt-hours (“gwh”)	215.7	219.7	(4.0)	(1.8)%

(a) Gas Utility’s total margin represents total revenues less total cost of sales. Electric Utility’s total margin represents total revenues less total cost of sales and revenue-related taxes, i.e. Electric Utility gross receipts taxes, of $1.1 million and $1.2 million during the three months ended June 30, 2016 and 2015, respectively. For financial statement purposes, revenue-related taxes are included in taxes other than income taxes in the Condensed Consolidated Statements of Income.

(b) Deviation from average heating degree days for the 15-year period 2000-2014 based upon weather statistics provided by the National Oceanic and Atmospheric Administration for airports located within Gas Utility’s service territory.

Temperatures in Gas Utility’s service territory during the 2016 three-month period based upon heating degree days were 11.9% colder than normal and 38% colder than the 2015 three-month period. Core market volumes increased 1.4 bcf (15.7%) reflecting the effects of the colder spring weather. Total Gas Utility distribution system throughput increased 5.0 bcf (13.0%) principally reflecting higher large firm fixed-fee delivery service volumes and, to a lesser extent, the higher core market volumes. Gas Utility’s core market customers comprise firm- residential, commercial and industrial (“retail core-market”) customers who purchase their gas from Gas Utility and, to a lesser extent, residential and small commercial customers who purchase their gas from alternate suppliers. Electric Utility kilowatt-hour sales were slightly lower than in the prior-year three-month period.

UGI Utilities total revenues decreased principally reflecting lower Electric Utility revenues ($3.6 million) while Gas Utility revenues were slightly higher than the prior-year three-month period. The lower 2016 three-month period Electric Utility revenues principally resulted from lower transmission revenues and, to a lesser extent, the effects of lower DS rates and slightly lower sales volumes. The slight increase in Gas Utility revenues principally reflects higher revenues from large firm delivery service customers ($2.2 million) resulting from higher firm delivery service volumes, and an increase in core market revenues ($0.3 million) partially offset by lower off-system sales revenues ($2.2 million). The slight increase in Gas Utility core market revenues reflects the effects of the higher core market throughput ($13.4 million) substantially offset by lower average PGC rates ($13.1 million) associated with retail core-market revenues. Because Gas Utility and Electric Utility are subject to reconcilable PGC and DS recovery mechanisms, increases or decreases in the actual cost of gas or electricity associated with customers who purchase their gas or electricity from UGI Utilities impact revenues and cost of sales but have no direct effect on retail core-market margin (see Note

5 to condensed consolidated financial statements). UGI Utilities cost of sales was $44.4 million in the 2016 three-month period compared with $53.7 million in the 2015 three-month period principally reflecting the combined effects of lower average Gas Utility PGC rates ($5.7 million) and lower cost of sales associated with off-system sales ($2.2 million). Electric Utility cost of sales in the 2016 three-month period was slightly lower primarily reflecting lower DS rates.

UGI Utilities 2016 three-month period total margin increased $6.2 million principally reflecting higher Gas Utility total margin from core market customers ($6.3 million) and slightly higher total margin from delivery service customers resulting from the higher throughput ($1.6 million). Electric Utility margin decreased $1.8 million principally reflecting lower transmission revenues and, to a much lesser extent, the slightly lower volume sales.

UGI Utilities operating income and income before income taxes increased $9.6 million and $10.4 million, respectively. The increases in operating income and income before income taxes during the 2016 three-month period principally reflect the previously mentioned increase in total margin ($6.2 million) and a $7.9 million decrease in operating and administrative expenses including lower distribution system ($2.8 million) and customer account expenses ($2.7 million). These benefits were partially offset by lower other operating income as the prior-year period included incremental income from construction services and the sale of PNG's heating, ventilation and air-conditioning business. The increase in income before income taxes also reflects lower interest expense principally due to lower average long-term debt outstanding.

Interest Expense and Income Taxes

Our interest expense in the 2016 three-month period decreased principally reflecting lower average long-term debt outstanding. Our effective income tax rate for the three months ended June 30, 2016 was comparable with the prior-year three-month period.

2016 nine-month period compared with 2015 nine-month period

Nine Months Ended June 30,	2016	2015	Decrease	
(Dollars in millions)				
Gas Utility:				
Revenues	$ 595.0	$ 847.9	$ (252.9)	(29.8)%
Total margin (a)	$ 373.4	$ 421.2	$ (47.8)	(11.3)%
Operating and administrative expenses	$ 132.0	$ 150.7	$ (18.7)	(12.4)%
Operating income	$ 183.9	$ 226.2	$ (42.3)	(18.7)%
Income before income taxes	$ 157.4	$ 196.5	$ (39.1)	(19.9)%
System throughput — billions of cubic feet ("bcf")				
Core market	61.7	76.4	(14.7)	(19.2)%
Total	165.6	176.3	(10.7)	(6.1)%
Heating degree days — % (warmer) colder than normal (b)	(12.9)%	7.5%	—	—
Electric Utility:				
Revenues	$ 65.3	$ 82.6	$ (17.3)	(20.9)%
Total margin (a)	$ 26.2	$ 29.8	$ (3.6)	(12.1)%
Operating and administrative expenses	$ 13.1	$ 14.7	$ (1.6)	(10.9)%
Operating income	$ 8.7	$ 11.3	$ (2.6)	(23.0)%
Income before income taxes	$ 7.3	$ 9.8	$ (2.5)	(25.5)%
Distribution sales — millions of kilowatt-hours ("gwh")	706.0	764.4	(58.4)	(7.6)%

(a) Gas Utility's total margin represents total revenues less total cost of sales. Electric Utility's total margin represents total revenues less total cost of sales and revenue-related taxes, i.e. Electric Utility gross receipts taxes, of $3.5 million and $4.4 million during the nine months ended June 30, 2016 and 2015, respectively. For financial statement purposes, revenue-related taxes are included in taxes other than income taxes on the Condensed Consolidated Statements of Income.

(b) Deviation from average heating degree days for the 15-year period 2000-2014 based upon weather statistics provided by the National Oceanic and Atmospheric Administration for airports located within Gas Utility's service territory.

Temperatures in Gas Utility's service territory during the 2016 nine-month period based upon heating degree days were 12.9% warmer than normal and 18.0% warmer than the 2015 nine-month period. In particular, Gas Utility temperatures in the critical heating-season month of December were 37% warmer than normal. Core market volumes declined 14.7 bcf (19.2%) reflecting the effects of the significantly warmer weather. Total Gas Utility distribution system throughput decreased 10.7 bcf (6.1%) principally reflecting the lower core market volumes partially offset by higher large firm delivery service volumes. Electric Utility kilowatt-hour sales were 7.6% lower than in the prior-year period principally reflecting the impact of the warmer weather on heating-related sales.

UGI Utilities revenues decreased principally reflecting a $252.9 million decrease in Gas Utility revenues and lower Electric Utility revenues ($17.3 million). The lower Gas Utility revenues principally reflect a decrease in core market revenues ($200.0 million) and lower off-system sales revenues ($50.9 million). The decrease in Gas Utility core market revenues reflects the effects of the lower core market throughput ($129.0 million) and lower average PGC rates during the 2016 nine-month period ($71.0 million). The lower Electric Utility revenues principally resulted from lower DS rates, lower sales volumes and lower transmission revenue in the 2016 nine-month period. UGI Utilities cost of sales was $257.3 million in the 2016 nine-month period compared with $475.1 million in the 2015 nine-month period principally reflecting the combined effects of the lower average Gas Utility PGC rates ($155.5 million), lower cost of sales associated with off-system sales ($50.9 million) and lower Gas Utility retail core-market volumes sold ($14.6 million). Electric Utility cost of sales was lower reflecting lower volumes sold and lower DS rates.

UGI Utilities 2016 nine-month period total margin decreased $52.4 million principally reflecting lower Gas Utility total margin from core market customers ($44.5 million) and, to a much lesser extent, lower total margin from large firm delivery service customers. The decrease in Gas Utility core market margin reflects the lower core market throughput. Electric Utility total margin decreased $3.6 million principally reflecting the lower volume sales as a result of the warmer nine-month period weather and lower transmission revenue.

UGI Utilities operating income and income before income taxes decreased $45.9 million and $42.6 million, respectively. The decreases in operating income and income before income taxes during the 2016 nine-month period principally reflects the decrease in total margin ($52.4 million), higher depreciation expense ($3.5 million) and lower other operating income which includes, among other things, higher environmental matters expense ($3.9 million), higher interest on PGC overcollections and lower margin from off-system sales. UGI Utilities operating and administrative expenses were $21.2 million lower primarily reflecting lower net preliminary development stage expenses associated with an information technology (“IT”) project and, to a lesser extent, lower uncollectible accounts and system maintenance expenses. During the three months ended March 31, 2016, we determined that certain preliminary stage costs associated with the IT project were probable of future recovery in rates in accordance with GAAP related to rate regulated entities. As a result, during the three months ended March 31, 2016, we capitalized $5.8 million of such costs including $5.4 million of which had been expensed prior to Fiscal 2016 (and $2.9 million of which had been expensed during the 2015 nine-month period) and recorded associated increases to utility plant and regulatory assets (See Note 5 to condensed consolidated financial statements). Income before income taxes also reflects lower interest expense principally due to lower average long-term debt outstanding.

Interest Expense and Income Taxes

Our interest expense in the 2016 nine-month period decreased principally reflecting lower average long-term debt outstanding. Our effective income tax rate for the nine months ended June 30, 2016 was comparable with the prior-year nine-month period.

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, 2016, totaled $82.4 million compared to $3.1 million at September 30, 2015. The significantly higher cash and cash equivalents balance at June 30, 2016, includes a substantial portion of the net proceeds from the issuance of $100 million of Senior Notes on June 30, 2016. These proceeds were used in early July 2016 to repay short-term borrowings (see below and Note 6 to condensed consolidated financial statements).

UGI Utilities’ total debt outstanding at June 30, 2016, was $780.0 million, which includes $130.0 million of short-term borrowings, compared with total debt outstanding of $693.7 million at September 30, 2015, which includes $71.7 million of short-term borrowings. Total long-term debt outstanding at June 30, 2016, comprises $550.0 million of Senior Notes and $100.0 million of Medium-Term Notes.

At June 30, 2016, the higher cash and cash equivalents, and the higher short-term borrowings, reflects the issuance of the long-term debt in late June 2016 and the subsequent timing of the use of the proceeds to repay short-term borrowings (as further described below).

In April 2016, UGI Utilities entered into a Note Purchase Agreement (the “2016 Note Purchase Agreement”) which provides for the private placement of (1) $100 million aggregate principal amount of 2.95% Senior Notes due June 30, 2026; (2) $200 million aggregate principal amount of 4.12% Senior Notes due September 30, 2046; and (3) $100 million aggregate principal amount of 4.12% Senior Notes due October 31, 2046 (collectively, the “Senior Notes”). On June 30 2016, UGI Utilities issued $100 million aggregate principal amount of 2.95% Senior Notes pursuant to the 2016 Note Purchase Agreement. The net proceeds from the issuance of the 2.95% Senior Notes were used to repay short-term borrowings under UGI Utilities’ Credit Agreement in early July 2016. The 4.12% Senior Notes due September 30, 2046 and the 4.12% Senior Notes due October 31, 2046 are expected to be issued in September 2016 and October 2016, respectively. UGI Utilities expects to use the net proceeds from the issuance of the 4.12% Senior Notes to repay UGI Utilities’ currently outstanding $175 million principal amount of 5.75% Senior Notes due September 30, 2016 and for general corporate purposes. Because UGI Utilities has the intent and ability to refinance the 5.75% Senior Notes on a long-term basis, the 5.75% Senior Notes have been classified as long-term debt on the June 30, 2016, Condensed Consolidated Balance Sheet. For further information on the 2016 Note Purchase Agreement, see Note 6 to condensed consolidated financial statements.

On March 31, 2016, concurrent with the pricing of the Senior Notes to be issued under the 2016 Note Purchase Agreement, UGI Utilities settled all of its then-existing IRPA contracts associated with such debt at a loss of $36.0 million. Because these IRPA contracts qualified for and were designated as cash flow hedges, the loss recognized in connection with the settled IRPAs has been recorded in AOCI and will be recognized in interest expense as future interest expense impacts earnings.

UGI Utilities has an unsecured revolving credit agreement (the “UGI Utilities 2015 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 2015 Credit Agreement are classified as short-term borrowings on the Condensed Consolidated Balance Sheets. During the 2016 and 2015 nine-month periods, average daily short-term borrowings under the UGI Utilities 2015 Credit Agreement and a predecessor agreement were $171.6 million and $73.6 million, respectively, and peak short-term borrowings totaled $232.0 million and $163.6 million, respectively. At June 30, 2016, UGI Utilities’ available borrowing capacity under the UGI Utilities 2015 Credit Agreement was $168 million. Peak short-term borrowings typically occur during the heating season months of December and January when UGI Utilities’ investment in working capital, principally accounts receivable and inventories, is generally greatest.

During the 2016 nine-month period, UGI Utilities repaid $72 million of maturing Medium-Term Notes. UGI Utilities used borrowings under the UGI Utilities 2015 Credit Agreement and existing cash balances to fund such repayments.

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 2015 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 2015 Credit Agreement to manage seasonal cash flow needs.

Cash provided by operating activities was $194.5 million in the 2016 nine-month period compared to $300.9 million in the prior-year period. Cash flow from operating activities before changes in operating working capital was $187.4 million in the 2016 nine-month period compared to $173.8 million recorded in the prior-year period. The greater cash flow from operations before changes in operating working capital in the 2016 nine-month period principally reflects greater noncash charges for deferred income taxes in the current-year period partially offset by the previously mentioned $36.0 million cash settlement of interest rate protection agreements and the effects of the lower operating results. Changes in operating working capital provided $7.1 million of operating cash flow during the 2016 nine-month period compared to $127.1 million of cash provided during the prior-year period. The lower cash from changes in working capital reflects net refunds of UGI Utilities purchased gas and electricity costs of $11.6 million compared with net overcollections of such costs in the prior-year nine-month period of $59.4 million. The lower net cash from changes in accounts receivable, accounts payable and inventories reflects, in large part, the impact on these items from lower natural gas costs and the lower volumes sold. Decreases in cash flow from changes in other current liabilities principally reflects lower cash flow from changes in accrued income taxes.

Investing activities. Cash used by investing activities was $165.2 million in the 2016 nine-month period compared to $148.3 million in the 2015 nine-month period. Total cash capital expenditures were $164.0 million in the 2016 nine-month period compared with $141.9 million recorded in the prior-year period. The increase in cash capital expenditures during the 2016 nine-month period principally reflects higher Gas Utility replacement and betterment capital expenditures. Changes in restricted cash in futures brokerage accounts provided $6.4 million of cash in the 2016 nine-month period compared with cash used of $0.1 million in the prior-year period reflecting lower required cash deposits in commodity futures brokerage accounts.

Financing activities. Cash provided by financing activities was $50.1 million in the 2016 nine-month period compared with cash used by financing activities of $148.5 million in the 2015 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. During the 2016 nine-month period there were net credit agreement borrowings of $58.3 million compared with net credit agreement repayments of $83.6 million during the prior-year period principally reflecting the impact of higher long-term debt repayments. During the 2016 nine-month period, UGI Utilities repaid $72.0 million of maturing Medium-Term Notes. UGI Utilities used borrowings under the UGI Utilities 2015 Credit Agreement and existing cash balances to fund these repayments. As previously mentioned, UGI Utilities issued $100 million of Senior Notes under the 2016 Note Purchase Agreement on June 30, 2016, and used substantially all of the net proceeds in early July 2016 (after the end of the quarter) to reduce short-term borrowings. Cash dividends in the 2016 nine-month period totaled $37.0 million compared to cash dividends of $45.6 million in the prior-year period.

REGULATORY MATTERS

UGI Gas Base Rate Filing. On January 19, 2016, UGI Utilities filed a rate request with the PUC to increase UGI Gas's annual base operating revenues for residential, commercial and industrial customers by $58.6 million. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. UGI Utilities requested that the new gas rates become effective March 19, 2016. The PUC entered an Order dated February 11, 2016, suspending the effective date for the rate increase to no later than October 19, 2016, to allow for investigation and public hearings. On June 30, 2016, a Joint Petition for Approval of Settlement of all issues supported by all active parties was filed with the PUC. Under the terms of the Joint Petition, UGI Utilities will be permitted, effective October 19, 2016, to increase UGI Gas' annual base distribution rates by $27.0 million. The Joint Petition is subject to receipt of a recommended decision by a PUC administrative law judge and an order of the PUC approving the settlement. The Company cannot predict the ultimate outcome of the rate case review process.

UGI Gas Consent Order and Agreement. In May 2016, UGI Gas executed a Consent Order and Agreement ("UGI Gas-COA") with the DEP with an effective date of October 1, 2016. The UGI Gas-COA will terminate in September 2031 if not extended by the parties. The UGI Gas-COA requires UGI Gas to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which MGP related facilities were operated ("UGI Gas MGP Properties"). Under this agreement, required environmental expenditures related to the UGI Gas MGP Properties are capped at $2.5 million in any calendar year. At June 30, 2016, our estimated accrued liabilities for environmental investigation and remediation costs related to the UGI Gas-COA totaled $43.8 million. UGI Gas has recorded associated regulatory assets for these costs because recovery of these costs from customers is probable (See Note 7 to condensed consolidated financial statements).

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 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, 2016, the fair values of our natural gas futures and option contracts were gains of $5.5 million.

Electric Utility's DS tariffs contain clauses which permit recovery of all prudently incurred power costs, including the cost of financial instruments used to hedge electricity costs, through the application of DS rates. Because of this ratemaking mechanism, there is limited power cost risk, including the cost of FTRs and forward electricity purchase contracts, associated with our Electric Utility operations. At June 30, 2016, all of our Electric Utility's forward electricity purchase contracts were subject to the NPNS exception. At June 30, 2016, the fair values of FTRs were not material.

In addition, Gas Utility and Electric Utility from time to time enter into exchange-traded gasoline futures contracts for a portion of gasoline volumes expected to be used in their operations. These gasoline futures contracts are recorded at fair value with changes in fair value reflected in operating expenses and other income. The amount of unrealized losses on these contracts and associated volumes under contract at June 30, 2016 were not material.

At June 30, 2016, UGI Utilities had $0.2 million of restricted cash in commodity brokerage accounts.

Interest Rate Risk

In order to reduce interest rate risk associated with near- or medium-term issuances of fixed-rate debt, from time to time we enter into IRPAs. There were no unsettled IRPAs outstanding at June 30, 2016.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company's disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports filed or submitted under the Securities Exchange Act of 1934, as amended, is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this Report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures, as of the end of the period covered by this Report, were effective at the reasonable assurance level.

(b) Change in Internal Control over Financial Reporting

No change in the Company's internal control over financial reporting occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

UGI UTILITIES, INC. AND SUBSIDIARIES

PART II OTHER INFORMATION

ITEM 1A. RISK FACTORS

In addition to the information presented in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended September 30, 2015, 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, 2016, 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, 2016, 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, 2016, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
101.INS	XBRL Instance			
101.SCH	XBRL Taxonomy Extension Schema			
101.CAL	XBRL Taxonomy Extension Calculation Linkbase			
101.DEF	XBRL Taxonomy Extension Definition Linkbase			
101.LAB	XBRL Taxonomy Extension Labels Linkbase			
101.PRE	XBRL Taxonomy Extension Presentation Linkbase			

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	UGI Utilities, Inc. (Registrant)
Date: August 5, 2016	By: /s/ Daniel J. Platt Daniel J. Platt Vice President - Finance and Chief Financial Officer
Date: August 5, 2016	By: /s/ Megan Mattern Megan Mattern Controller & Principal Accounting Officer

UGI UTILITIES, INC. AND SUBSIDIARIES

EXHIBIT INDEX

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101.INS	XBRL Instance
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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,			
	2016	2015	2014	2013	2012
Earnings:					
Earnings before income taxes	$ 164,670	$ 200,539	$ 207,929	$ 171,010	$ 142,971
Interest expense	27,686	40,400	37,897	38,578	41,599
Amortization of debt discount and expense	236	728	575	731	814
Estimated interest component of rental expense	1,953	2,728	2,398	2,090	2,121
	$ 194,545	$ 244,395	$ 248,799	$ 212,409	$ 187,505
Fixed Charges:					
Interest expense	$ 27,686	$ 40,400	$ 37,897	$ 38,578	$ 41,599
Amortization of debt discount and expense	236	728	575	731	814
Allowance for funds used during construction (capitalized interest)	333	407	227	286	10
Estimated interest component of rental expense	1,953	2,728	2,398	2,090	2,121
	$ 30,208	$ 44,263	$ 41,097	$ 41,685	$ 44,544
Ratio of earnings to fixed charges	6.44	5.52	6.05	5.10	4.21

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 5, 2016

/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 5, 2016

/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, 2016 (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 5, 2016	Date: August 5, 2016