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, 2015

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, 2015, 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

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

	June 30, 2015	September 30, 2014	June 30, 2014
ASSETS			
Current assets:			
Cash and cash equivalents	$ 16,522	$ 12,401	$ 28,480
Restricted cash	3,683	3,592	1,109
Accounts receivable (less allowances for doubtful accounts of $12,534, $6,992 and $13,517, respectively)	89,340	65,080	97,144
Accounts receivable — related parties	2,039	2,865	3,484
Accrued utility revenues	7,716	14,330	7,950
Inventories	33,376	95,219	58,750
Deferred income taxes	29,904	1,492	11,908
Regulatory assets	2,763	13,159	9,354
Derivative instruments	1,285	1,028	1,703
Prepaid expenses & other current assets	13,551	18,535	11,057
Total current assets	200,179	227,701	230,939
Property, plant and equipment, at cost (less accumulated depreciation and amortization of $918,311, $886,268 and $888,279, respectively)	1,781,668	1,682,284	1,635,867
Goodwill	182,145	182,145	182,145
Regulatory assets	251,479	255,007	233,272
Derivative instruments	111	—	—
Other assets	7,623	7,506	7,618
Total assets	$ 2,423,205	$ 2,354,643	$ 2,289,841
LIABILITIES AND STOCKHOLDER'S EQUITY			
Current liabilities:			
Current maturities of long-term debt	$ 72,000	$ 20,000	$ 20,000
Short-term borrowings	2,700	86,300	—
Accounts payable	44,687	58,453	47,396
Accounts payable — related parties	5,477	11,761	21,131
Deferred fuel refunds	45,564	306	—
Derivative instruments	4,412	1,632	31
Other current liabilities	151,760	99,030	140,404
Total current liabilities	326,600	277,482	228,962
Long-term debt	550,000	622,000	622,000
Deferred income taxes	478,108	461,461	454,871
Deferred investment tax credits	3,681	3,933	4,017
Pension and postretirement benefit obligations	91,804	98,363	61,991
Other noncurrent liabilities	50,752	51,567	53,439
Total liabilities	1,500,945	1,514,806	1,425,280
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	471,796	471,071	470,844
Retained earnings	396,823	316,688	340,714
Accumulated other comprehensive loss	(6,618)	(8,181)	(7,256)
Total common stockholder's equity	922,260	839,837	864,561
Total liabilities and stockholder's equity	$ 2,423,205	$ 2,354,643	$ 2,289,841

See accompanying notes to condensed consolidated financial statements.

Table of Contents

UGI UTILITIES, INC. AND SUBSIDIARIES

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
	2015	2014	2015	2014
Revenues	$ 143,490	$ 152,694	$ 931,369	$ 965,549
Costs and expenses:				
Cost of sales — gas, fuel and purchased power (excluding depreciation shown below)	53,691	63,323	475,079	515,612
Operating and administrative expenses	51,393	49,862	156,858	145,313
Operating and administrative expenses — related parties	2,647	2,385	9,567	7,997
Taxes other than income taxes	3,706	3,768	12,613	12,748
Depreciation	14,985	14,048	44,300	41,485
Amortization	928	844	2,682	2,500
Other operating income, net	(4,044)	(1,256)	(8,253)	(3,623)
	123,306	132,974	692,846	722,032
Operating income	20,184	19,720	238,523	243,517
Interest expense	9,985	10,433	31,245	28,036
Income before income taxes	10,199	9,287	207,278	215,481
Income taxes	2,892	2,397	81,543	87,195
Net income	$ 7,307	$ 6,890	$ 125,735	$ 128,286

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,	
	2015	2014	2015	2014
Net income	$ 7,307	$ 6,890	$ 125,735	$ 128,286
Other comprehensive income:				
Reclassifications of net losses on derivative instruments (net of tax of $(277), $(278), $(833) and $(834), respectively)	392	393	1,175	1,176
Benefit plans reclassifications of actuarial losses and prior service costs (net of tax of $(92), $(67), $(275) and $(206), respectively)	128	95	388	288
Other comprehensive income	520	488	1,563	1,464
Comprehensive income	$ 7,827	$ 7,378	$ 127,298	$ 129,750

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, 2015	Nine Months Ended June 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 125,735	$ 128,286
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	46,982	43,985
Deferred income taxes, net	(10,417)	18,747
Provision for uncollectible accounts	10,997	11,657
Other, net	526	(2,809)
Net change in:		
Accounts receivable and accrued utility revenues	(27,817)	(44,530)
Inventories	61,843	30,911
Deferred fuel and power costs, net of changes in unsettled derivatives	59,397	(17,611)
Accounts payable	(14,884)	4,070
Other current assets	631	4,690
Other current liabilities	47,939	27,947
Net cash provided by operating activities	300,932	205,343
CASH FLOWS FROM INVESTING ACTIVITIES:		
Expenditures for property, plant and equipment	(141,884)	(104,117)
Net costs of property, plant and equipment disposals	(6,358)	(5,222)
(Increase) decrease in restricted cash	(91)	2,072
Net cash used by investing activities	(148,333)	(107,267)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payment of dividends	(45,600)	(57,549)
Issuances of long-term debt	—	175,000
Repayments of long-term debt	(20,000)	(175,000)
Decrease in short-term borrowings	(83,600)	(17,500)
Other	722	746
Net cash used by financing activities	(148,478)	(74,303)
Cash and cash equivalents increase	$ 4,121	$ 23,773
CASH AND CASH EQUIVALENTS:		
End of period	$ 16,522	$ 28,480
Beginning of period	12,401	4,707
Increase	$ 4,121	$ 23,773

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 (“UGI Penn HVAC Services, Inc.”) which operated principally in the PNG service territory (“HVAC Business”). The assets of the HVAC business principally comprising customer contracts were sold on June 1, 2015. The sale did not have a material impact on the condensed consolidated financial statements.

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

Note 2 — Summary of Significant Accounting Policies

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

The accompanying condensed consolidated financial statements are unaudited and have been prepared in accordance with the rules and regulations of the U.S. Securities and Exchange Commission (“SEC”). They include all adjustments that we consider necessary for a fair statement of the results for the interim periods presented. Such adjustments consisted only of normal recurring items unless otherwise disclosed. The September 30, 2014, 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, 2014 (“the Company’s 2014 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.

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

Accounting Standards Not Yet Adopted

Measurement of Inventory. In July 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2015-11, "Simplifying the Measurement of Inventory." This ASU amends existing guidance to require inventory to be measured at the lower of cost or net realizable value. Entities will continue to apply their existing impairment models to inventories that are accounted for using “last-in, first-out” and the “retail inventory” methods. The amendments in this ASU are effective for annual periods beginning after December 15, 2016 (Fiscal 2018) including interim periods within those fiscal years. Early adoption is permitted. Entities will apply the new guidance prospectively after the date of adoption. The adoption is not expected to have a material impact on the Company’s financial statements.

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

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

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. Early adoption is permitted. Entities will apply the new guidance retrospectively to all periods presented. The Company expects to adopt the new guidance in the fourth quarter of Fiscal 2015. 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." This ASU supersedes the revenue recognition requirements in Accounting Standards Codification ("ASC") 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 company expects to be entitled in exchange for those goods or services. This standard is effective for the Company for interim and annual periods beginning October 1, 2017 (Fiscal 2018) and allows for either full retrospective adoption or modified retrospective adoption. On July 9, 2015, the FASB voted to delay the effective date by one year. We have not yet selected a transition method and are currently evaluating the impact of adopting this guidance on our consolidated financial statements.

Note 4 — Inventories

Inventories comprise the following:

	June 30, 2015	September 30, 2014	June 30, 2014
Gas Utility natural gas	$ 19,205	$ 82,664	$ 45,701
Materials, supplies and other	14,171	12,555	13,049
Total inventories	$ 33,376	$ 95,219	$ 58,750

At June 30, 2015, UGI Utilities is a party to three principal storage contract administrative agreements ("SCAAs") having terms of three years. Two of the SCAAs are with Energy Services, LLC ("Energy Services"), a second-tier, wholly owned subsidiary of UGI (see Note 12) and one of the SCAAs is with a non-affiliate. Pursuant to SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon commencement of the SCAAs, will receive a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the terms of the SCAAs. The historical cost of natural gas storage inventories released under the SCAAs, which represents a portion of Gas Utility's total natural gas storage inventories, and any exchange receivable (representing amounts of natural gas inventories used by the other parties to the agreement but not yet replenished for which UGI Utilities has the rights), are included in the caption "Gas Utility natural gas" in the table above.

The carrying value of gas storage inventories released under the SCAAs at June 30, 2015, September 30, 2014 and June 30, 2014, comprising 4.5 billion cubic feet ("bcf"), 11.6 bcf and 6.1 bcf of natural gas, was $11,337, $49,897 and $28,299, respectively. At June 30, 2015, September 30, 2014 and June 30, 2014, UGI Utilities held a total of $17,700, $17,600 and $17,600, respectively, of security deposits from its SCAA counterparties. These amounts are included in other current liabilities on the Condensed Consolidated Balance Sheets.

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 2014 Annual Report. UGI Utilities 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, 2015	September 30, 2014	June 30, 2014
Regulatory assets:			
Income taxes recoverable	$ 111,807	$ 110,709	$ 107,166
Underfunded pension and postretirement plans	103,250	110,116	89,236
Environmental costs	14,441	14,616	14,581
Deferred fuel and power costs	—	11,732	9,354
Removal costs, net	19,635	16,790	15,620
Other	5,109	4,203	6,669
Total regulatory assets	$ 254,242	$ 268,166	$ 242,626
Regulatory liabilities:			
Postretirement benefits	$ 19,687	$ 18,594	$ 17,545
Environmental overcollections	—	349	1,631
Deferred fuel and power refunds	45,564	306	—
State tax benefits — distribution system repairs	10,894	10,076	9,271
Other	1,377	3,172	1,862
Total regulatory liabilities (a)	$ 77,522	$ 32,497	$ 30,309

(a) Regulatory liabilities, other than deferred fuel and power refunds, are recorded in other current and noncurrent liabilities in the Condensed Consolidated Balance Sheets.

Deferred fuel and power — costs and 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, 2015, September 30, 2014, and June 30, 2014, were $(729), $(1,363) and $680, respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Previous to March 1, 2015, we did not designate these purchase contracts as an NPNS election under GAAP. Therefore, we recognized 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 June 30, 2015, September 30, 2014, and June 30, 2014, the fair values of Electric Utility's electricity supply contracts were gains (losses) of $(1,428), $345 and $760, respectively. These amounts are reflected in current and noncurrent derivative assets and current and noncurrent derivative liabilities on the Condensed Consolidated Balance Sheets with equal and offsetting amounts reflected in deferred fuel and power costs and refunds in the table above. 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 (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, 2015, September 30, 2014, and June 30, 2014, were not material.

Distribution System Improvement Charge. On April 14, 2012, legislation enabling gas and electric utilities in Pennsylvania to seek to charge recovery of eligible capital investment in distribution system infrastructure improvement projects became effective. 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, for up to five percent of distribution rates. 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. PNG and CPG began seeking permission to include a DSIC in their tariffs in 2014, while UGI Gas has not had a general rate filing within the required time period to be eligible. Beginning on April 1, 2015, PNG was able to include a DSIC charge in its tariff rate in accordance with a PUC order. The impact of the DSIC charge at PNG did not have a material effect on Gas Utility results of operations.

Note 6 — Debt

On March 27, 2015, UGI Utilities entered into an unsecured revolving credit agreement (the “UGI Utilities 2015 Credit Agreement”) with a group of banks providing for borrowings up to $300,000 (including a $100,000 sublimit for letters of credit). Concurrently with entering into the UGI Utilities 2015 Credit Agreement, UGI Utilities terminated its then-existing $300,000 revolving credit agreement dated as of May 25, 2011. Under the UGI Utilities 2015 Credit Agreement, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks’ prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.75% and is based upon the credit ratings of certain indebtedness of UGI Utilities. The UGI Utilities 2015 Credit Agreement requires UGI Utilities not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.0. The UGI Utilities 2015 Credit Agreement is currently scheduled to expire in March 2016, but may be extended by UGI Utilities to March 2020 if on or before March 25, 2016, the Company receives approval for the UGI Utilities 2015 Credit Agreement by the PUC. The Company filed to obtain such approval on June 30, 2015.

Note 7 — Commitments and Contingencies

Contingencies

Environmental Matters

CPG is party to a Consent Order and Agreement (“CPG-COA”) with the Pennsylvania Department of Environmental Protection (“DEP”) requiring CPG to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which manufactured gas plant (“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 $1,800 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, 2015 and 2014, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $9,595 and $11,381, respectively. We have recorded associated regulatory assets for these costs because recovery of these costs from customers is probable.

From the late 1800s through the mid-1900s, UGI Utilities and its former subsidiaries owned and operated a number of 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

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

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. Pursuant to the requirements of the Public Utility Holding Company Act of 1935, 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 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 are currently receiving regulatory recovery of estimated environmental investigation and remediation costs associated with Pennsylvania sites. At June 30, 2015, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Gas was material for UGI Utilities.

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.

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 relating to the Company's employees include the following components:

	Pension Benefits		Other Postretirement Benefits	
Three Months Ended June 30,	2015	2014	2015	2014
Service cost	$ 1,741	$ 1,623	$ 48	$ 41
Interest cost	5,628	5,721	119	127
Expected return on assets	(7,225)	(6,649)	(153)	(139)
Amortization of:				
Prior service cost (benefit)	87	87	(160)	(160)
Actuarial loss	2,199	1,660	32	37
Net benefit cost (income)	2,430	2,442	(114)	(94)
Change in associated regulatory liabilities	—	—	938	918
Net benefit cost after change in regulatory liabilities	$ 2,430	$ 2,442	$ 824	$ 824

	Pension Benefits		Other Postretirement Benefits	
Nine Months Ended June 30,	2015	2014	2015	2014
Service cost	$ 5,222	$ 4,869	$ 145	$ 123
Interest cost	16,883	17,163	356	381
Expected return on assets	(21,674)	(19,949)	(459)	(417)
Amortization of:				
Prior service cost (benefit)	261	261	(480)	(480)
Actuarial loss	6,595	4,982	95	111
Net benefit cost (income)	7,287	7,326	(343)	(282)
Change in associated regulatory liabilities	—	—	2,813	2,754
Net benefit cost after change in regulatory liabilities	$ 7,287	$ 7,326	$ 2,470	$ 2,472

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, 2015 and 2014, the Company made contributions to the Pension Plan of $8,348 and $10,975, respectively. The Company expects to make additional discretionary cash contributions of approximately $2,800 to the Pension Plan during the remainder of Fiscal 2015.

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 calculated under GAAP 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, 2015 and 2014.

We also participate in an unfunded and non-qualified defined benefit supplemental executive retirement plan. Net benefit costs associated with this plan for all periods presented were not material.

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

Note 9 — Fair Value Measurements

Derivative Instruments

The following table presents on a gross basis our derivative assets and liabilities including both current and noncurrent portions, that are measured at fair value on a recurring basis within the fair value hierarchy, as of June 30, 2015, September 30, 2014 and June 30, 2014:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
June 30, 2015:				
Assets:				
Commodity contracts	$ 1,510	$ 469	$ —	$ 1,979
Liabilities:				
Commodity contracts	$ (2,390)	$ (2,605)	$ —	$ (4,995)
September 30, 2014:				
Assets:				
Commodity contracts	$ 679	$ 1,018	$ —	$ 1,697
Liabilities:				
Commodity contracts	$ (2,095)	$ (206)	$ —	$ (2,301)
June 30, 2014 (a):				
Assets:				
Commodity contracts	$ 1,500	$ 1,016	$ —	$ 2,516
Liabilities:				
Commodity contracts	$ (693)	$ (151)	$ —	$ (844)

(a) Certain immaterial amounts have been revised to correct the classification of derivatives.

The fair values of our Level 1 exchange-traded commodity futures and option derivative contracts and certain non exchange-traded electricity forward 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, 2015, were $622,000 and $683,521, respectively. The carrying amount and estimated fair value of our long-term debt (including current maturities) at June 30, 2014, were $642,000 and $708,916, 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. For more information on the accounting for our derivative instruments, see Note 2, "Summary of Significant Accounting Policies," in the Company's 2014 Annual Report.

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, 2015 and 2014, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 13.1 million dekatherms and 10.9 million dekatherms, respectively. At June 30, 2015, 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 by Electric Utility prior to March 1, 2015, Electric Utility chose not to elect the NPNS exception under GAAP related to these derivative instruments and the fair values of these contracts are reflected in current and noncurrent derivative instrument assets and liabilities in 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, 2015 and 2014, the volumes of Electric Utility's forward electricity purchase contracts were 494.5 million kilowatt hours and 315.8 million kilowatt hours, respectively. At June 30, 2015, the maximum period over which these contracts extend is 11 months.

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, 2015 and 2014, the total volumes associated with FTRs totaled 381.6 million kilowatt hours and 319.7 million kilowatt hours, respectively. At June 30, 2015, 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 and swap 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. As of June 30, 2015 and 2014, we had no unsettled IRPAs. At June 30, 2015, the amount of net losses associated with IRPAs expected to be reclassified into earnings during the next twelve months is $2,550.

Derivative Instrument Credit Risk

Our natural gas exchange-traded futures contracts generally require cash deposits in margin accounts. At June 30, 2015, restricted cash in brokerage accounts totaled $3,683. At June 30, 2014, there was $1,109 restricted cash in brokerage accounts.

Fair Value of Derivative Instruments

The following table presents the Company's derivative assets and liabilities on a gross basis as of June 30, 2015 and 2014:

	June 30, 2015	June 30, 2014 (a)
Derivative assets:		
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	$ 1,943	$ 2,450
Derivatives not subject to PGC and DS mechanisms:		
Commodity contracts	36	66
Total derivative assets	$ 1,979	$ 2,516
Derivative liabilities:		
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	$ (4,807)	$ (844)
Derivatives not subject to PGC and DS mechanisms:		
Commodity contracts	(188)	—
Total derivative liabilities	$ (4,995)	$ (844)

(a) Certain immaterial amounts have been revised to correct the classification of derivatives.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities are presented net by counterparty on our 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 our 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)

The following table presents the Company's derivative assets and liabilities, as well as the effects of offsetting, as of June 30, 2015 and 2014:

	Gross Amounts Recognized	Gross Amounts Offset in Balance Sheet	Net Amounts Recognized	Cash Collateral (Received) Pledged	Net Amounts Recognized in Balance Sheet
June 30, 2015					
Derivative assets	$ 1,979	$ (583)	$ 1,396	$ —	$ 1,396
Derivative liabilities	$ (4,995)	$ 583	$ (4,412)	$ —	$ (4,412)
June 30, 2014					
Derivative assets	$ 2,516	$ (813)	$ 1,703	$ —	$ 1,703
Derivative liabilities	$ (844)	$ 813	$ (31)	$ —	$ (31)

Effect of Derivative Instruments

The following table provides information on the effects of derivative instruments on the Condensed Consolidated Statements of Income and changes in AOCI for the three and nine months ended June 30, 2015 and 2014:

	Gain (Loss) Recognized in AOCI		Gain (Loss) Reclassified from AOCI into Income		Location of Gain (Loss) Reclassified from AOCI into Income
Three Months Ended June 30,	2015	2014	2015	2014	
Cash Flow Hedges:					
Interest rate contracts	$ —	$ —	$ (669)	$ (671)	Interest expense

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Three Months Ended June 30,	2015	2014	
Derivatives Not Subject to PGC and DS Mechanisms:			
Gasoline contracts	$ 111	$ 49	Operating expenses/other operating income, net

	Gain (Loss) Recognized in AOCI		Gain (Loss) Reclassified from AOCI into Income		Location of Gain (Loss) Reclassified from AOCI into Income
Nine Months Ended June 30,	2015	2014	2015	2014	
Cash Flow Hedges:					
Interest rate contracts	$ —	$ —	$ (2,008)	$ (2,010)	Interest expense

	Gain (Loss) Recognized in Income		Location of Gain (Loss) Recognized in Income
Nine Months Ended June 30,	2015	2014	
Derivatives Not Subject to PGC and DS Mechanisms:			
Gasoline contracts	$ (415)	$ 128	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.

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, 2015 and 2014:

	Postretirement Benefit Plans	Derivative Instruments	Total
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 interest rate protection agreements	—	392	392
AOCI - June 30, 2015	$ (5,923)	$ (695)	$ (6,618)
Three Months Ended June 30, 2014			
AOCI - March 31, 2014	$ (5,090)	$ (2,654)	$ (7,744)
Reclassifications of benefit plan actuarial losses and prior service cost	95	—	95
Reclassifications of net losses on interest rate protection agreements	—	393	393
AOCI - June 30, 2014	$ (4,995)	$ (2,261)	$ (7,256)

	Postretirement Benefit Plans	Derivative Instruments	Total
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 cost	388	—	388
Reclassifications of net losses on interest rate protection agreements	—	1,175	1,175
AOCI - June 30, 2015	$ (5,923)	$ (695)	$ (6,618)
Nine Months Ended June 30, 2014			
AOCI - September 30, 2013	$ (5,283)	$ (3,437)	$ (8,720)
Reclassifications of benefit plan actuarial losses and prior service cost	288	—	288
Reclassifications of net losses on interest rate protection agreements	—	1,176	1,176
AOCI - June 30, 2014	$ (4,995)	$ (2,261)	$ (7,256)

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 in the Condensed Consolidated Statements of Income. In addition, UGI Utilities provides limited administrative services to UGI and certain of UGI’s subsidiaries under PUC approved affiliated interest agreements. Amounts billed to these entities by UGI Utilities for all periods presented were not material.

UGI Utilities is a party to two SCAAs with Energy Services which have terms of three years. Under the SCAAs, UGI Utilities has, among other things, and subject to recall for operational purposes, released certain storage and transportation contracts to

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

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 $5,691 and $10,898 during the three and nine months ended June 30, 2015, respectively, and $16,894 and $23,590 during the three and nine months ended June 30, 2014, respectively. In conjunction with the SCAAs, UGI Utilities received security deposits from Energy Services. The amount of such security deposits, which are included in other current liabilities on the Condensed Consolidated Balance Sheets, was $10,700, $10,600, and $10,600 as of June 30, 2015, September 30, 2014 and June 30, 2014, 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, 2015, September 30, 2014 and June 30, 2014, comprising 2.6 bcf, 7.7 bcf and 4.0 bcf of natural gas, was $6,809, $33,057 and $19,410, 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 principally during the heating season months of November through March. The capacity charges for these transactions (exclusive of transactions pursuant to the SCAAs) during the three and nine months ended June 30, 2015 totaled $2,380 and $45,413, respectively. During the three and nine months ended June 30, 2014, such transactions totaled $1,551 and $34,259, respectively, and are reflected in cost of sales.

From time to time, the Company sells natural gas or pipeline capacity to Energy Services. 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. During the three and nine months ended June 30, 2014, revenues associated with such sales to Energy Services totaled $9,869 and $102,118, 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, 2015, such purchases totaled $8,431 and $79,956, respectively. During the three and nine months ended June 30, 2014, such purchases totaled $22,114 and $114,811, 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 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 2014 Annual Report. We evaluate the performance of our Gas Utility and Electric Utility segments principally based upon their income before income taxes.

No single customer represents more than ten percent of our consolidated revenues and there are no significant intersegment transactions. In addition, all of our reportable segments' revenues are derived from sources within the United States, and all of our reportable segments' long-lived assets are located in the United States.

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

Financial information by business segment follows:

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	$	43,315	$	41,324	$	1,991	$	—

Three Months Ended June 30, 2014:

			Reportable Segments					
	Total		Gas Utility		Electric Utility		Other	
Revenues	$	152,694	$	128,264	$	23,954	$	476
Cost of sales	$	63,323	$	49,257	$	14,066	$	—
Depreciation and amortization	$	14,892	$	13,774	$	1,118	$	—
Operating income	$	19,720	$	17,115	$	2,304	$	301
Interest expense	$	10,433	$	9,904	$	529	$	—
Income before income taxes	$	9,287	$	7,211	$	1,775	$	301
Capital expenditures	$	38,215	$	35,955	$	2,260	$	—

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	$	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	$	—	$	—

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

Nine Months Ended June 30, 2014:

			Reportable Segments					
		Total		Gas Utility		Electric Utility		Other
Revenues	$	965,549	$	879,989	$	84,467	$	1,093
Cost of sales	$	515,612	$	463,492	$	52,120	$	—
Depreciation and amortization	$	43,985	$	40,733	$	3,252	$	—
Operating income	$	243,517	$	233,728	$	9,485	$	304
Interest expense	$	28,036	$	26,652	$	1,384	$	—
Income before income taxes	$	215,481	$	207,076	$	8,101	$	304
Capital expenditures	$	104,117	$	98,806	$	5,311	$	—
As of June 30, 2014								
Total assets (at period end)	$	2,289,841	$	2,147,407	$	142,434	$	—
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 2014 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, 2015 (“2015 three-month period”) with the three months ended June 30, 2014 (“2014 three-month period”) and the nine months ended June 30, 2015 (“2015 nine-month period”) with the nine months ended June 30, 2014 (“2014 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.

2015 three-month period compared with 2014 three-month period

Three Months Ended June 30,	2015	2014	Increase (Decrease)	
(Millions of dollars)				
Gas Utility:				
Revenues	$ 119.4	$ 128.3	$ (8.9)	(6.9)%
Total margin (a)	$ 78.1	$ 79.0	$ (0.9)	(1.1)%
Operating and administrative expenses	$ 48.6	$ 47.0	$ 1.6	3.4 %
Operating income	$ 15.1	$ 17.1	$ (2.0)	(11.7)%
Income before income taxes	$ 5.6	$ 7.2	$ (1.6)	(22.2)%
System throughput — billions of cubic feet (“bcf”)				
Core market	8.9	9.2	(0.3)	(3.3)%
Total	38.6	37.5	1.1	2.9 %
Heating degree days — % (warmer) than normal (b)	(22.2)%	(6.3)%	—	—
Electric Utility:				
Revenues	$ 23.9	$ 24.0	$ (0.1)	(0.4)%
Total margin (a)	$ 10.3	$ 8.6	$ 1.7	19.8 %
Operating and administrative expenses	$ 5.1	$ 5.1	$ —	— %
Operating income	$ 4.1	$ 2.3	$ 1.8	78.3 %
Income before income taxes	$ 3.6	$ 1.8	$ 1.8	100.0 %
Distribution sales — millions of kilowatt-hours (“gwh”)	219.7	217.7	2.0	0.9 %

(a) Gas Utility’s total margin represents total revenues less total cost of sales. Electric Utility’s total margin represents total revenues less total cost of sales and revenue-related taxes, i.e. Electric Utility gross receipts taxes, of $1.2 million and $1.3 million during the three months ended June 30, 2015 and 2014, 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 1995-2009 based upon weather statistics provided by the National Oceanic and Atmospheric Administration (“NOAA”) for airports located within Gas Utility’s service territory.

Gas Utility

Temperatures in Gas Utility’s service territory in the 2015 three-month period based upon heating degree days were 22.2% warmer than normal and 17.0% warmer than the 2014 three-month period. Notwithstanding the warmer temperatures, total distribution system throughput increased 1.1 bcf (2.9%) principally reflecting higher delivery service volumes partially offset by slightly lower core market volumes. The lower core market volumes reflect the effects of the warmer spring weather partially offset by the benefits of a 1.7% increase in the number of core market customers. 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 much lesser extent, residential and small commercial customers who purchase their gas from alternate suppliers.

Gas Utility revenues decreased $8.9 million during the 2015 three-month period principally reflecting lower revenues from core market customers ($5.3 million). The decrease in core market revenues principally reflects the effects of the lower core market throughput and slightly lower average PGC rates during the 2015 three-month period. Increases or decreases in retail core-market revenues and cost of sales principally result from changes in retail core-market volumes and the level of gas costs collected through the PGC recovery mechanism. Under the PGC recovery mechanism, Gas Utility records the cost of gas associated with sales to retail core-market customers at amounts included in PGC rates. The difference between actual gas costs and the amounts included in rates is deferred on the balance sheet as a regulatory asset or liability and represents amounts to be collected from or refunded to customers in a future period. As a result of this PGC recovery mechanism, increases or decreases in the cost of gas associated with retail core-market customers have no direct effect on retail core-market margin. Gas Utility's cost of sales was $41.4 million in the 2015 three-month period compared with $49.3 million in the 2014 three-month period principally reflecting the effects of the lower average PGC rates ($4.1 million) and lower retail core-market volumes sold ($1.2 million).

Gas Utility 2015 three-month period total margin decreased $0.9 million principally reflecting lower margin from interruptible delivery service customers and the effects of the slightly lower core market throughput.

Gas Utility operating income and income before income taxes during the 2015 three-month period decreased $2.0 million and $1.6 million, respectively, compared with the prior-year period. The decrease in Gas Utility operating income and income before income taxes during the 2015 three-month period principally reflects the decrease in total margin ($0.9 million), higher depreciation expense ($1.1 million) and slightly higher operating and administrative expenses ($1.6 million) partially offset by an increase in other operating income ($1.7 million). The increase in operating and administrative expenses includes, among other things, higher distribution system maintenance expenses and general and administrative expenses. The higher other operating income includes incremental margin from construction services.

Electric Utility

Temperatures based upon heating degree days during the 2015 three-month period were approximately 25.1% warmer than normal and approximately 15.1% warmer than the prior year. Cooling degree days in the current-year period were 57.4% higher than the prior-year period. Electric Utility distribution sales were slightly higher than in the prior-year three-month period. Electric Utility revenues decreased due primarily to lower average default service ("DS") rates partially offset by higher transmission revenue primarily reflecting the effects of a $1.6 million adjustment associated with prior years. Electric Utility cost of sales decreased to $12.3 million in the 2015 three-month period from $14.1 million in the 2014 three-month period principally reflecting the effects of the lower average DS rates.

Electric Utility total margin, net of gross receipts taxes, increased $1.7 million principally reflecting an increase in transmission revenue including a $1.6 million recovery of transmission revenues associated with prior years.

Electric Utility operating income and income before income taxes in the 2015 three-month period were each $1.8 million higher than the 2014 three-month period principally reflecting the previously mentioned increase in total margin.

Interest Expense and Income Taxes

Our interest expense in the 2015 three-month period was slightly lower than the prior-year three month period principally reflecting lower average long-term debt outstanding. Our effective income tax rate for the three months ended June 30, 2015 was comparable to the effective tax rate in the prior-year period.

2015 nine-month period compared with 2014 nine-month period

Nine Months Ended June 30,	2015	2014	Increase (Decrease)	
Gas Utility:				
Revenues	$ 847.9	$ 880.0	$ (32.1)	(3.6)%
Total margin (a)	$ 421.2	$ 416.5	$ 4.7	1.1 %
Operating and administrative expenses	$ 150.7	$ 138.0	$ 12.7	9.2 %
Operating income	$ 226.2	$ 233.7	$ (7.5)	(3.2)%
Income before income taxes	$ 196.5	$ 207.1	$ (10.6)	(5.1)%
System throughput — billions of cubic feet (“bcf”)				
Core market	76.4	75.1	1.3	1.7 %
Total	176.3	172.8	3.5	2.0 %
Heating degree days — % colder than normal (b)	7.2%	10.2%	—	—
Electric Utility:				
Revenues	$ 82.6	$ 84.5	$ (1.9)	(2.2)%
Total margin (a)	$ 29.9	$ 27.7	$ 2.2	7.9 %
Operating and administrative expenses	$ 14.7	$ 14.5	$ 0.2	1.4 %
Operating income	$ 11.3	$ 9.5	$ 1.8	18.9 %
Income before income taxes	$ 9.8	$ 8.1	$ 1.7	21.0 %
Distribution sales — millions of kilowatt-hours (“gwh”)	764.4	775.8	(11.4)	(1.5)%

(a) Gas Utility’s total margin represents total revenues less total cost of sales. Electric Utility’s total margin represents total revenues less total cost of sales and revenue-related taxes, i.e. Electric Utility gross receipts taxes, of $4.4 million and $4.6 million during the nine months ended June 30, 2015 and 2014, 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 1995-2009 based upon weather statistics provided by the National Oceanic and Atmospheric Administration (“NOAA”) for airports located within Gas Utility’s service territory.

Gas Utility

Temperatures in Gas Utility’s service territory in the 2015 nine-month period based upon heating degree days were 7.2% colder than normal but 2.8% warmer than the 2014 nine-month period. Total distribution system throughput increased 3.5 bcf, notwithstanding the warmer weather, principally reflecting higher firm delivery service volumes and slightly higher core market volumes reflecting, in large part, a 1.7% increase in the number of core market customers.

Gas Utility revenues decreased $32.1 million during the 2015 nine-month period principally reflecting lower revenues from off-system sales ($30.4 million) and lower other revenues partially offset by higher revenues from core market customers ($3.0 million). The increase in core market revenues principally reflects the effects of the higher core market throughput offset by slightly lower average PGC rates during the 2015 nine-month period. Gas Utility’s cost of sales was $426.7 million in the 2015 nine-month period compared with $463.5 million in the 2014 nine-month period principally reflecting the effects of the lower off-system sales ($30.4 million) and the slightly lower average PGC rates.

Gas Utility nine-month period total margin increased $4.7 million principally reflecting higher core market total margin ($6.3 million) on the higher core market sales. This increase was partially offset principally by lower margin from interruptible customers.

Gas Utility operating income and income before income taxes during the 2015 nine-month period decreased $7.5 million and $10.6 million, respectively, compared to the prior-year period. The $7.5 million decrease in Gas Utility operating income, notwithstanding the $4.7 million increase in total margin, principally reflects higher operating and administrative expenses and higher depreciation expense. Operating and administrative expenses were modestly higher than the prior-year period principally reflecting, among other things, higher 2015 nine-month period distribution system maintenance expenses ($5.3 million), higher depreciation expense ($2.7 million) and higher employee benefits and other general administrative expenses. The $10.6 million decrease in Gas Utility income before income taxes reflects the lower operating income ($7.5 million) and higher long-term debt interest expense.

Electric Utility

Temperatures based upon heating degree days during the 2015 nine-month period were approximately 3.2% colder than normal and approximately 3.6% warmer than the prior year. Total kilowatt-hour sales decreased by 1.5% reflecting in large part the effects of the warmer weather on heating-related sales in addition to customer conservation. The $1.9 million decrease in Electric Utility revenues primarily reflects the lower sales and lower average DS rates partially offset by higher transmission revenue. Electric Utility cost of sales decreased to $52.7 million in the 2015 nine-month period from $56.8 million in the 2014 nine-month period principally reflecting the effects of the lower sales and lower average DS rates.

Electric Utility total margin, net of gross receipts taxes, increased $2.2 million principally reflecting an increase in transmission revenue including a $1.6 million recovery of transmission revenues associated with prior years.

Electric Utility operating income and income before income taxes in the 2015 nine-month period increased $1.8 million and $1.7 million, respectively, principally reflecting the increase in total margin partially offset by higher general and administrative expenses.

Interest Expense and Income Taxes

Our interest expense in the 2015 nine-month period was higher than the prior year principally reflecting interest on the 4.98% Senior Notes due March 2044 issued in March 2014 the proceeds of which were used to refinance UGI Utilities' 364-day Term Loan Credit Agreement. Our effective income tax rate for the nine months ended June 30, 2015 was slightly lower than the prior-year nine-month period.

FINANCIAL CONDITION AND LIQUIDITY

UGI Utilities' total debt outstanding at June 30, 2015, was $624.7 million, which includes $2.7 million of short-term borrowings, compared with total debt outstanding of $728.3 million at September 30, 2014, which includes $86.3 million of short-term borrowings. Total long-term debt outstanding at June 30, 2015, comprises $450.0 million of Senior Notes and $172.0 million of Medium-Term Notes.

On March 27, 2015, UGI Utilities entered into 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). Concurrently with entering into the UGI Utilities 2015 Credit Agreement, UGI Utilities terminated its then-existing $300 million revolving credit agreement dated as of May 25, 2011. Under the UGI Utilities 2015 Credit Agreement, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.75% and is based upon the credit ratings of certain indebtedness of UGI Utilities. The UGI Utilities 2015 Credit Agreement requires UGI Utilities not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.0. The UGI Utilities 2015 Credit Agreement is currently scheduled to expire in March 2016, but may be extended by UGI Utilities to March 2020 if on or before March 25, 2016, the Company receives approval for the UGI Utilities 2015 Credit Agreement by the Pennsylvania Public Utility Commission. The Company filed to obtain such approval on June 30, 2015.

Borrowings under the UGI Utilities 2015 Credit Agreement and the predecessor credit agreement are classified as short-term borrowings on the Consolidated Balance Sheets. During the 2015 and 2014 nine-month periods, average daily short-term borrowings were $73.6 million and $30.4 million, respectively, and peak short-term borrowings totaled $163.6 million and $84.0 million, respectively. At June 30, 2015, UGI Utilities' available borrowing capacity under the UGI Utilities 2015 Credit Agreement was $295.3 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.

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 its Credit Agreement to manage seasonal cash flow needs.

Cash provided by operating activities was $300.9 million in the 2015 nine-month period compared to $205.3 million in the prior-year period. Cash flow from operating activities before changes in operating working capital was $173.8 million in the 2015 nine-month period compared to $199.9 million recorded in the prior-year period. Changes in operating working capital provided $127.1 million of operating cash flow during the 2015 nine-month period compared to $5.5 million of cash used during the prior-year period. Among other things, cash flows from changes in operating working capital includes $59.4 million of cash flow from overcollections of gas costs under the PGC mechanism during the 2015 nine-month period compared to undercollections of gas costs of $17.6 million during the prior-year period. The significantly higher overcollections in the current-year period reflects the impact of significant declines in natural gas prices.

Investing activities. Cash used by investing activities was $148.3 million in the 2015 nine-month period compared to $107.3 million in the 2014 nine-month period. Total cash capital expenditures were $141.9 million in the 2015 nine-month period compared with $104.1 million recorded in the prior-year period. The increase in the 2015 nine-month period principally reflects higher Gas Utility growth and maintenance capital expenditures. Changes in restricted cash in futures brokerage accounts used $0.1 million of cash in the 2015 nine-month period compared with cash provided of $2.1 million in the prior-year period.

Financing activities. Cash used by financing activities was $148.5 million in the 2015 nine-month period compared with $74.3 million in the 2014 nine-month period. Financing activity cash flows are primarily the result of net borrowings and repayments under our Credit Agreement, cash dividends paid to UGI and capital contributions from UGI. During the 2015 nine-month period there were net Credit Agreement repayments of $83.6 million compared with net repayments of $17.5 million during the prior-year period. The higher Credit Agreement repayments in the 2015 nine-month period reflects the use of a portion of the previously mentioned increase in 2015 nine-month period cash flow from operating activities. Cash dividends in the 2015 nine-month period totaled $45.6 million compared to cash dividends of $57.5 million in the prior-year period. During the 2015 three-month period the Company repaid $20 million of maturing Medium-Term debt.

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, 2015 and 2014, the fair values of our natural gas futures and option contracts were gains (losses) of $(0.7) million and $0.7 million, respectively.

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, 2015 and 2014, the fair values of Electric Utility’s electricity supply contracts were gains (losses) of $(1.4) million and $0.8 million, respectively. At June 30, 2015 and 2014, 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 and swap contracts for a portion of gasoline volumes expected to be used in their operations. These gasoline futures and swap contracts are recorded at fair value with changes in fair value reflected in net income.

At June 30, 2015, UGI Utilities had $3.7 million of restricted cash in commodity brokerage accounts. At June 30, 2014, UGI Utilities had $1.1 million 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, 2015 and 2014.

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 Principal 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 Principal 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 Principal Financial Officer concluded that the Company's disclosure controls and procedures, as of the end of the period covered by this Report, were effective at the reasonable assurance level.

(b) Change in Internal Control over Financial Reporting

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

PART II OTHER INFORMATION

ITEM 1A. RISK FACTORS

In addition to the information presented in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended September 30, 2014, 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:

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, 2015, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
31.2	Certification by the Principal Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2015, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
32	Certification by the Chief Executive Officer and the Principal Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2015, 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 7, 2015	By: /s/ Ann P. Kelly
	Ann P. Kelly Controller (Principal Accounting Officer)

Table of Contents

EXHIBIT INDEX

12.1	Computation of ratio of earnings to fixed charges.
31.1	Certification by the Chief Executive Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2015, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification by the Principal Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2015, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification by the Chief Executive Officer and the Principal Financial Officer relating to the Registrant's Report on Form 10-Q for the quarter ended June 30, 2015, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

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

	Nine Months Ended June 30,	Year Ended September 30,			
	2015	2014	2013	2012	2011
Earnings:					
Earnings before income taxes	$ 207,278	$ 207,929	$ 171,010	$ 142,971	$ 168,693
Interest expense	31,245	38,471	39,309	42,412	42,728
Amortization of debt discount and expense	588	575	731	814	1,060
Estimated interest component of rental expense	1,993	2,398	2,090	2,121	1,740
	$ 241,104	$ 249,373	$ 213,140	$ 188,318	$ 214,221
Fixed Charges:					
Interest expense	$ 31,245	$ 38,471	$ 39,309	$ 42,412	$ 42,728
Amortization of debt discount and expense	588	575	731	814	1,060
Allowance for funds used during construction (capitalized interest)	294	227	286	10	90
Estimated interest component of rental expense	1,993	2,398	2,090	2,121	1,740
	$ 34,120	$ 41,671	$ 42,416	$ 45,357	$ 45,618
Ratio of earnings to fixed charges	7.07	5.98	5.02	4.15	4.70

EXHIBIT 31.1

CERTIFICATION

I, Robert F. Beard, certify that:

1. I have reviewed this periodic report on Form 10-Q of UGI Utilities, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2015

/s/ Robert F. Beard

Robert F. Beard
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Kirk R. Oliver, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 7, 2015

/s/ Kirk R. Oliver

Kirk R. Oliver
Vice President -
Financial Strategy
(Principal Financial
Officer)

EXHIBIT 32

Certification by the Chief Executive Officer and Principal Financial Officer

Relating to a Periodic Report Containing Financial Statements

I, Robert F. Beard, Chief Executive Officer, and I, Kirk R. Oliver, Principal 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, 2015 (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	PRINCIPAL FINANCIAL OFFICER
/s/ Robert F. Beard	/s/ Kirk R. Oliver
Robert F. Beard	Kirk R. Oliver
Date: August 7, 2015	Date: August 7, 2015