UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTIONS 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 2015

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.)**

P. O. Box 12677, 2525 N. 12th Street, Suite 360
Reading, PA 19612
(Address of Principal Executive Offices) (Zip Code)

(610) 796-3400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 ☐

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 ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

At November 17, 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.

The Registrant meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format permitted by that General Instruction.

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FORWARD-LOOKING INFORMATION

Information contained in this Annual Report on Form 10-K may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. 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 which 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 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.

PART I:

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

GENERAL

UGI Utilities, Inc. ("UGI Utilities" or the "Company") is a public utility company that owns and operates three natural gas distribution utilities in Pennsylvania and portions of one Maryland county and an electric utility in Pennsylvania. We are a wholly owned subsidiary of UGI Corporation ("UGI").

The Gas Utility segment ("Gas Utility") consists of the regulated natural gas distribution businesses of UGI Utilities, UGI Penn Natural Gas, Inc. ("PNG"), and UGI Central Penn Gas, Inc. ("CPG"). Gas Utility serves nearly 617,000 customers in eastern and central Pennsylvania and more than five hundred customers in portions of one Maryland county. UGI Utilities' natural gas distribution utility is referred to as "UGI Gas". The Electric Utility segment ("Electric Utility") consists of the regulated electric distribution business of UGI Utilities, serving approximately 62,000 customers in northeastern Pennsylvania. Gas Utility is regulated by the Pennsylvania Public Utility Commission ("PUC") and, with respect to its several hundred customers in Maryland, the Maryland Public Service Commission. Electric Utility is regulated by the PUC.

UGI Utilities was incorporated in Pennsylvania in 1925. Our executive offices are located at P.O. Box 12677, 2525 N. 12th Street, Suite 360, Reading, Pennsylvania 19612, and our telephone number is (610) 796-3400. In this report, the terms "Company" and "UGI Utilities," as well as the terms, "our," "we," and "its," are sometimes used to refer to UGI Utilities, Inc. or, collectively UGI Utilities, Inc. and its consolidated subsidiaries. The terms "Fiscal 2015," "Fiscal 2014" and "Fiscal 2013" refer to the fiscal years ended September 30, 2015, September 30, 2014 and September 30, 2013, respectively.

GAS UTILITY

Service Area; Revenue Analysis

Gas Utility provides natural gas distribution services to nearly 617,000 customers in certificated portions of 46 eastern and central Pennsylvania counties through its distribution system. Contemporary materials, such as plastic or coated steel, comprise approximately 88% of Gas Utility's 12,000 miles of gas mains, with bare steel pipe comprising approximately 9% and cast iron pipe comprising approximately 3% of Gas Utility's gas mains. In accordance with Gas Utility's agreement with the PUC, Gas Utility will replace the cast iron portion of its gas mains by March of 2027 and the bare steel portion by September 2041. The service area includes the cities of Allentown, Bethlehem, Easton, Harrisburg, Hazleton, Lancaster, Lebanon, Reading, Scranton, Wilkes-Barre, Lock Haven, Pittston, Pottsville, and Williamsport, Pennsylvania, and the boroughs of Honesdale and Milford, Pennsylvania. Located in Gas Utility's service area are major production centers for basic industries such as specialty metals, aluminum, glass, and paper product manufacturing. Gas Utility also distributes natural gas to more than 500 customers in portions of one Maryland county.

System throughput (the total volume of gas sold to or transported for customers within Gas Utility's distribution system) for Fiscal 2015 was approximately 213.5 billion cubic feet ("bcf"). System sales of gas accounted for approximately 31% of system throughput, while gas transported for residential, commercial and industrial customers who bought their gas from others accounted for approximately 69% of system throughput.

Sources of Supply and Pipeline Capacity

Gas Utility is permitted to recover prudently incurred costs of natural gas it sells to its customers. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Market Risk Disclosures" and Note 4 to Consolidated Financial Statements. Gas Utility meets its service requirements by utilizing a diverse mix of natural gas purchase contracts with marketers and producers, along with storage and transportation service contracts. These arrangements enable Gas Utility to purchase gas from Gulf Coast, Mid-Continent, Appalachian and Marcellus sources. For the transportation and storage function, Gas Utility has long-term agreements with a number of pipeline companies, including Texas Eastern Transmission, LP, Columbia Gas Transmission, LLC, Transcontinental Gas Pipeline Company, LLC, Dominion Transmission, Inc., ANR Pipeline Company, and Tennessee Gas Pipeline Company, L.L.C.

Gas Supply Contracts

During Fiscal 2015, Gas Utility purchased approximately 82.8 bcf of natural gas for sale to core-market customers (principally comprised of firm- residential, commercial and industrial customers that purchase their gas from Gas Utility (“retail core-market”)) and off-system sales customers. Approximately 83% of the volumes purchased were supplied under agreements with 10 suppliers. The remaining 17% of gas purchased by Gas Utility was supplied by approximately 24 producers and marketers. Gas supply contracts for Gas Utility are generally no longer than 12 months. Gas Utility also has long-term contracts with suppliers for natural gas peaking supply during the months of November through March.

Seasonality

Because many of its customers use gas for heating purposes, Gas Utility’s sales are seasonal. During Fiscal 2015, approximately 65% of Gas Utility's sales volume was supplied, and more than 90% of Gas Utility’s operating income was earned, during the peak heating season from October through March.

Competition

Natural gas is a fuel that competes with electricity and oil and, to a lesser extent, with propane and coal. Competition among these fuels is primarily a function of their comparative price and the relative cost and efficiency of the equipment. Natural gas generally benefits from a competitive price advantage over oil, electricity, and propane, although the price gap between natural gas and oil narrowed in Fiscal 2015 due to a reduction in the price of oil. Fuel oil dealers compete for customers in all categories, including industrial customers. Gas Utility responds to this competition with marketing and sales efforts designed to retain, expand, and grow its customer base.

In substantially all of its service territories, Gas Utility is the only regulated gas distribution utility having the right, granted by the PUC or by law, to provide gas distribution services. Larger commercial and industrial customers have the right to purchase gas supplies from entities other than natural gas distribution utility companies. As a result of Pennsylvania's Natural Gas Choice and Competition Act, effective July 1, 1999, all of Gas Utility’s customers, including core-market customers, have been afforded this opportunity.

A number of Gas Utility's commercial and industrial customers have the ability to switch to an alternate fuel at any time and, therefore, are served on an interruptible basis under rates that are competitively priced with respect to the alternate fuel. Margin from these customers, therefore, is affected by the difference or “spread” between the customers’ delivered cost of gas and the customers’ delivered cost of the alternate fuel, the frequency and duration of interruptions, and alternative firm service options. See “Gas Utility and Electric Utility Regulation and Rates - Gas Utility Rates.”

Approximately 18% of Gas Utility’s annual throughput volume for commercial and industrial customers includes non-interruptible customers with locations that afford them the opportunity of seeking transportation service directly from interstate pipelines, thereby bypassing Gas Utility. In addition, approximately 25% of Gas Utility’s annual throughput volume for commercial and industrial customers is from customers who are served under interruptible rates and are also in a location near an interstate pipeline. Gas Utility has 25 such customers, 24 of which have transportation contracts extending beyond fiscal year 2016. The majority of these customers are served under transportation contracts having 3 to 20 year terms and all are among the largest customers for Gas Utility in terms of annual volumes. No single customer represents, or is anticipated to represent, more than 5% of Gas Utility’s total revenues.

Outlook for Gas Service and Supply

Gas Utility anticipates having adequate pipeline capacity, peaking services, and other sources of supply available to it to meet the full requirements of all firm customers on its system through fiscal year 2016. Supply mix is diversified, market priced, and delivered pursuant to a number of long-term and short-term primary firm transportation and storage arrangements, including transportation contracts held by some of Gas Utility's larger customers.

During Fiscal 2015, Gas Utility supplied transportation service to five major co-generation installations and four electric generation facilities. Gas Utility continues to seek new residential, commercial, and industrial customers for both firm and interruptible service. In Fiscal 2015, Gas Utility connected nearly 2,400 new commercial and industrial customers. In the residential market sector, Gas Utility connected approximately 15,000 residential heating customers during Fiscal 2015. Over 10,000 of these customers converted to natural gas heating from other energy sources, mainly oil and electricity. New home construction customers and existing non-heating gas customers who added gas heating systems to replace other energy sources primarily accounted for the other residential heating connections in Fiscal 2015.

UGI Utilities continues to monitor and participate, where appropriate, in rulemaking and individual rate and tariff proceedings before the Federal Energy Regulatory Commission ("FERC") affecting the rates and the terms and conditions under which Gas Utility transports and stores natural gas. Among these proceedings are those arising out of certain FERC orders and/or pipeline filings that relate to (i) the pricing of pipeline services in a competitive energy marketplace; (ii) the flexibility of the terms and conditions of pipeline service tariffs and contracts; and (iii) pipelines' requests to increase their base rates, or change the terms and conditions of their storage and transportation services.

UGI Utilities' objective in negotiations with interstate pipeline and natural gas suppliers, and in proceedings before regulatory agencies, is to assure availability of supply, transportation, and storage alternatives to serve market requirements at the lowest cost possible, taking into account the need for security with guaranteed deliverability and reliability of supply. Consistent with that objective, UGI Utilities negotiates the terms of firm transportation capacity on all pipelines serving it, arranges for appropriate storage and peak-shaving resources, negotiates with producers for competitively priced gas purchases and aggressively participates in regulatory proceedings related to transportation rights and costs of service.

ELECTRIC UTILITY

Service Area; Sales Analysis

Electric Utility supplies electric service to approximately 62,000 customers in portions of Luzerne and Wyoming counties in northeastern Pennsylvania through a system consisting of over 2,200 miles of transmission and distribution lines and 13 substations. For Fiscal 2015, approximately 57% of sales volume came from residential customers, 32% from commercial customers, and 11% from industrial and other customers.

Sources of Supply

Electric Utility is permitted to recover prudently incurred electricity costs, including costs to obtain supply to meet its customers' energy requirements, pursuant to a supply plan filed and approved by the PUC. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Market Risk Disclosures" and Note 4 to Consolidated Financial Statements. Electric Utility distributes electricity that it purchases from wholesale markets and electricity that customers purchase from other suppliers. During Fiscal 2015, seven retail electric generation suppliers provided energy for customers representing approximately 24% of Electric Utility's sales volume. See "Gas Utility and Electric Utility Regulation and Rates - Electric Utility Rates."

Competition

As a result of the Electricity Generation Customer Choice and Competition Act ("ECC Act"), all Pennsylvania retail electric customers have the ability to choose their retail electric generation supplier. Under the ECC Act and Act 129 of 2008, which revised the default service requirements contained in Chapter 28 of the Public Utility Code, Electric Utility remains the "default service" provider for its customers who do not choose an alternate retail electric generation supplier. In Fiscal 2015, Electric Utility served nearly all of the electric customers within its service territory and is the only regulated electric utility having the right, granted by the PUC or by law, to distribute electricity in its service territory. As an energy source, electricity competes with natural gas, oil, propane, and other heating fuels for residential heating purposes.

The terms and conditions under which Electric Utility provides default service, and rules governing the rates that may be charged for such service, have been established in the Default Service ("DS") rate plans approved by the PUC. Consistent with the terms of the DS rate plans, default service rates are designed to recover all reasonable and prudent costs incurred in providing electricity to default service customers. See "Gas Utility and Electric Utility Regulation and Rates - Electric Utility Rates."

GAS UTILITY AND ELECTRIC UTILITY REGULATION AND RATES

Pennsylvania Public Utility Commission Jurisdiction

UGI Utilities' gas and electric utility operations are subject to regulation by the PUC as to rates, terms and conditions of service, accounting matters, issuance of securities, contracts and other arrangements with affiliated entities, and various other matters. There are primarily two types of rates that UGI Utilities may charge customers for gas and electric service: (i) rates designed to recover purchased gas costs ("PGCs") and electric default service costs; and (ii) rates designed to recover costs other than PGCs and electric default service costs. Rates designed to recover PGCs and electric default service costs are reviewed in PGC and electric default service rate proceedings. Rates designed to recover costs other than PGCs and electric default service costs are primarily established in general base rate proceedings.

Gas Utility Rates

The gas service tariffs for UGI Gas, PNG, and CPG contain PGC rates applicable to firm retail rate schedules. These PGC rates permit recovery of substantially all of the prudently incurred costs of natural gas that UGI Gas, PNG, and CPG sell to their customers. PGC rates are reviewed and approved annually by the PUC. UGI Gas, PNG, and CPG may request quarterly or, under certain conditions, monthly adjustments to reflect the actual cost of gas. Quarterly adjustments become effective on one day's notice to the PUC and are subject to review during the next annual PGC filing. Each proposed annual PGC rate is required to be filed with the PUC six months prior to its effective date. During this period, the PUC holds hearings to determine whether the proposed rate reflects a least-cost fuel procurement policy consistent with the obligation to provide safe, adequate and reliable service. After completion of these hearings, the PUC issues an order permitting the collection of gas costs at levels that meet such standard. The PGC mechanism also provides for an annual reconciliation.

UGI Gas has two PGC rates: (i) applicable to small, firm, retail core-market customers consisting of the residential and small commercial and industrial classes; and (ii) applicable to firm, high-load factor, customers served on three separate rates. PNG and CPG each have one PGC rate applicable to all customers. Base rates for each of UGI Gas, PNG, and CPG were last established in 1995, 2009, and 2011, respectively.

On February 20, 2014, the PUC entered an order approving a Growth Extension Tariff ("GET Gas") program under which UGI Gas, PNG, and CPG may invest up to $5 million per year for five years, or $75 million in the aggregate for all three utilities, to extend natural gas utility pipelines to provide service to unserved and underserved areas within their respective territories. Under the GET Gas program, customers utilizing the extended pipeline to receive natural gas will pay a monthly surcharge over a 10-year period to cover the cost of the extension. Gas Utility began connecting customers under the GET Gas program in October 2014.

In February 2012, Act 11 of 2012 ("Act 11") became effective. Among other things, Act 11 authorized the PUC to permit electric and gas distribution companies, between base rate cases and subject to certain conditions, to recover reasonable and prudent costs incurred to repair, improve, or replace eligible property through a Distribution System Improvement Charge ("DSIC") assessed to customers. DSICs are subject to quarterly adjustment, are capped at five percent of total customer charges absent a PUC-granted exception, may only be sought if a base rate case has been filed within the last five years, and are subject to certain earnings tests. In addition, Act 11 requires affected utilities to obtain approval of long-term infrastructure improvement plans ("LTIIP") from the PUC. Act 11 also authorized electric and gas distribution companies to utilize a fully forecasted future test year when establishing rates in base rate cases before the PUC.

The PUC approved LTIIPs for UGI Gas in July 2014, and for PNG and CPG in September 2014. The PUC also approved DSIC mechanisms for PNG and CPG in September 2014 and July 2015, respectively; UGI Gas was not eligible to request a DSIC because it has not filed a base rate case within the last five years. PNG first began collecting revenues under its DSIC in April 2015. CPG has not yet qualified to begin collecting revenues under its DSIC.

Electric Transmission and Wholesale Power Sale Rates

FERC has jurisdiction over the rates and terms and conditions of service of electric transmission facilities used for wholesale or retail choice transactions. Electric Utility owns electric transmission facilities that are within the control area of the PJM Interconnection, LLC ("PJM") and are dispatched in accordance with a FERC-approved open access tariff and associated agreements administered by PJM. PJM is a regional transmission organization that regulates and coordinates generation supply and the wholesale delivery of electricity. Electric Utility receives certain revenues collected by PJM, determined under a formulary rate schedule that is adjusted in June of each year to reflect annual changes in Electric Utility's electric transmission revenue requirements, when its transmission facilities are used by third parties.

FERC has jurisdiction over the rates and terms and conditions of service of wholesale sales of electric capacity and energy. Electric Utility has a tariff on file with FERC pursuant to which it may make power sales to wholesale customers at market-based rates.

Electric Utility Rates

Electric Utility is permitted to recover prudently incurred electricity costs, including costs to obtain supply to meet its customers' energy requirements, pursuant to a supply plan filed with the PUC. Electric Utility's operations are subject to regulation by the PUC as to rates, terms and conditions of service, accounting matters, issuance of securities, contracts and other arrangements with affiliated entities, and various other matters. The most recent general base rate increase for Electric Utility became effective in 1996. PUC default service regulations became applicable to Electric Utility's provision of default service effective January 1, 2010 and Electric Utility, consistent with these regulations, has received PUC approval through May 31, 2017 of (i) default service tariff rules, (ii) a reconcilable default service cost rate recovery mechanism to recover the cost of acquiring default service supplies, (iii) a plan for meeting the post-2009 requirements of the Alternative Energy Portfolio Standards Act ("AEPS Act"), which requires Electric Utility to directly or indirectly acquire certain percentages of its supplies from designated alternative energy sources, and (iv) a reconcilable AEPS Act cost recovery rate mechanism to recover the costs of complying with AEPS Act requirements applicable to default service supplies for service rendered through May 31, 2017. Under these rules, default service rates for most customers are adjusted quarterly.

FERC Market Manipulation Rules and Other FERC Enforcement and Regulatory Powers

UGI Utilities is subject to Section 4A of the Natural Gas Act, which prohibits the use or employment of any manipulative or deceptive devices or contrivances in connection with the purchase or sale of natural gas or natural gas transportation subject to the jurisdiction of FERC, and FERC regulations that are designed to promote the transparency, efficiency, and integrity of gas markets. UGI Utilities is also subject to Section 222 of the Federal Power Act which prohibits the use or employment of any manipulative or deceptive devices or contrivances in connection with the purchase or sale of electric energy or transmission service subject to the jurisdiction of FERC, and FERC regulations that are designed to promote the transparency, efficiency, and integrity of electric markets. Under provisions of the Energy Policy Act of 2005 ("EPACT 2005"), Electric Utility is subject to certain electric reliability standards established by FERC and administered by an Electric Reliability Organization ("ERO"). Electric Utility anticipates that substantially all the costs of complying with the ERO standards will be recoverable through its PJM formulary electric transmission rate schedule.

EPACT 2005 also granted FERC authority to impose substantial civil penalties for the violation of any regulations, orders, or provisions under the Federal Power Act and Natural Gas Act, and clarified FERC's authority over certain utility or holding company mergers or acquisitions of electric utilities or electric transmitting utility property valued at $10 million or more.

State Tax Surcharge Clauses

UGI Utilities' gas and electric service tariffs contain state tax surcharge clauses. The surcharges are recomputed whenever any of the tax rates included in their calculation are changed. These clauses protect UGI Utilities from the effects of increases in most of the Pennsylvania taxes to which it is subject.

Utility Franchises

UGI Utilities holds a certificate of public convenience issued by the PUC and certain "grandfather rights" predating the adoption of the Pennsylvania Public Utility Code and its predecessor statutes, which it believes are adequate to authorize it to carry on its business in substantially all of the territories to which it now renders gas or electric service. Under applicable Pennsylvania law, UGI Utilities has certain rights of eminent domain as well as the right to maintain its facilities in streets and highways in its territories.

Other Government Regulation

In addition to regulation by the PUC and FERC, the gas and electric utility operations of UGI Utilities are subject to various federal, state and local laws governing environmental matters, occupational health and safety, pipeline safety and other matters. UGI Utilities is subject to the requirements of the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation, and Liability Act, and comparable state statutes with respect to the release of hazardous substances on property owned or operated by UGI Utilities. See Note 12 to Consolidated Financial Statements.

Employees

At September 30, 2015, UGI Utilities had approximately 1,520 employees.

BUSINESS SEGMENT INFORMATION

The table stating the amounts of revenues, operating income and identifiable assets attributable to UGI Utilities' operating segments for the 2015, 2014 and 2013 fiscal years appears in Note 16 to Consolidated Financial Statements included in this Report and is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Decreases in the demand for natural gas and electricity because of warmer-than-normal heating season weather could adversely affect our results of operations, financial condition and cash flows because our rate structure does not contain weather normalization provisions.

Because many of our customers rely on natural gas or electricity to heat their homes and businesses, our results of operations are adversely affected by warmer-than-normal heating season weather. Weather conditions have a significant impact on the demand for natural gas and electricity for heating purposes. Accordingly, demand for natural gas and electricity used for heating purposes is generally at its highest during the peak heating season of October through March and is directly affected by the severity of the winter weather. Our rate structures do not contain weather normalization provisions to compensate for warmer-than-normal weather conditions, and we have historically sold less natural gas and electricity when weather conditions are milder and, consequently, earned less income. As a result, warmer-than-normal heating season weather could reduce our net income, harm our financial condition and adversely affect our cash flows.

Energy efficiency and technology advances, as well as price induced customer conservation, may result in reduced demand for our energy products and services.

The trend toward increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, may reduce the demand for energy products. Prices for natural gas are subject to volatile fluctuations in response to changes in supply and other market conditions. During periods of high energy commodity costs, our prices generally increase which may lead to customer conservation. A reduction in demand could lower our revenues, and, therefore, lower our net income and adversely affect our cash flows. State and/or federal regulation may require mandatory conservation measures which would reduce the demand for our energy products. We cannot predict the materiality of the effect of future conservation measures or the effect that any technological advances in heating, conservation, energy generation or other devices might have on our operations.

Volatility in credit and capital markets may restrict our ability to grow, increase the likelihood of defaults by our customers and counterparties and adversely affect our operating results.

The volatility in credit and capital markets may create additional risks to our business in the future. We are exposed to financial market risk (including refinancing risk) resulting from, among other things, changes in interest rates and conditions in the credit and capital markets. Developments in the credit markets during the past few years increase our possible exposure to the liquidity, default and credit risks of our suppliers, counterparties associated with derivative financial instruments and our customers. Although we believe that current financial market conditions, if they were to continue for the foreseeable future, will not have a significant impact on our ability to fund our existing operations, such market conditions could restrict our ability to grow, limit the scope of major capital projects if access to credit and capital markets is limited, or adversely affect our operating results.

Economic recession, volatility in the stock market and the low interest rate environment may negatively impact our pension liability.

Economic recession, volatility in the stock market and the low interest rate environment have had a significant impact on our pension liability and funded status. Declines in the stock or bond market and valuation of stocks or bonds, combined with continued low interest rates, could further impact our pension liability and funded status and increase the amount of required contributions to our pension plans.

Changes in commodity market prices may have a significant negative effect on our liquidity.

Depending on the terms of our contracts with suppliers as well as our use of financial instruments including natural gas futures and option contracts to reduce volatility in the cost of natural gas we purchase, changes in the market price of electricity and natural gas could create payment obligations for the Company and expose us to significant liquidity risks.

Our transmission and distribution systems may not operate as planned, which may increase our expenses or decrease our revenues and, thus, have an adverse effect on our financial results.

Our ability to manage operational risk with respect to our transmission and distribution systems is critical to our financial results. Our business also faces several risks, including the breakdown or failure of or damage to equipment or processes (especially due to severe weather or natural disasters), accidents and other factors. Operation of our transmission and distribution systems below our expectations may result in lost revenues or increased expenses, including higher maintenance costs.

Our need to comply with, and respond to industry-wide changes resulting from, comprehensive, complex, and sometimes unpredictable government regulations, including regulatory initiatives aimed at increasing competition within our industry, may increase our costs and limit our revenue growth, which may adversely affect our operating results.

There are many governmental regulations that have an impact on our businesses. Existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company that may affect our businesses in ways that we cannot predict.

Moreover, we may be unable to timely respond to changes within the energy and utility sectors that may result from regulatory initiatives to further increase competition within our industry. Such regulatory initiatives may create opportunities for additional competitors to enter our markets and, as a result, we may be unable to maintain our revenues or continue to pursue our current business strategy.

Regulators may not allow timely recovery of costs for us in the future, which may adversely affect our results of operations.

Our Gas Utility and Electric Utility distribution operations are subject to regulation by the PUC. The PUC, among other things, approves the rates that we may charge to our utility customers, thus impacting the returns that we may earn on the assets that are dedicated to those operations. We expect that UGI Utilities and its subsidiaries will periodically file requests with the PUC to increase base rates that they charge customers. If we are required in a rate proceeding to reduce the rates we charge our utility customers, or if we are unable to obtain approval for timely rate increases from the PUC, particularly when necessary to cover increased costs, our revenue growth will be limited and earnings may decrease.

We are subject to operating and litigation risks that may not be covered by insurance.

Our business operations are subject to all of the operating hazards and risks normally incidental to the handling, storage and distribution of combustible products, such as natural gas. These risks could result in substantial losses due to personal injury and/or loss of life, and severe damage to and destruction of property and equipment arising from explosions and other catastrophic events, including acts of terrorism. As a result, we are sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business. There can be no assurance that our insurance will be adequate to protect us from all material expenses related to pending and future claims or that such levels of insurance will be available in the future at economical prices.

The risk of terrorism may adversely affect the economy and the price and availability of natural gas.

Terrorist attacks may adversely impact the price and availability of natural gas as well as our results of operations, our ability to raise capital, and our future growth. The impact that the foregoing may have on our industry in general, and on us in particular, is not known at this time. An act of terror could result in disruptions of natural gas supplies and markets, cause price volatility in the cost of natural gas, and our infrastructure facilities could be direct or indirect targets. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth. Instability in the financial markets as a result of terrorism could also affect our ability to raise capital.

If we are unable to protect our information technology systems against service interruption, misappropriation of data, or breaches of security resulting from cyber security attacks or other events, our operations could be disrupted and our business and reputation may suffer.

In the ordinary course of business, we rely on information technology systems, including the Internet and third-party hosted services, to support a variety of business processes and activities and to store sensitive data, including (i) intellectual property, (ii) our proprietary business information and that of our suppliers and business partners, (iii) personally identifiable information of our customers and employees, and (iv) data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities. In addition, we rely on our information technology systems to process financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal, and tax requirements. Despite our security measures, our information technology systems may be vulnerable to attacks by hackers or breached due to employee error, malfeasance, sabotage, or other disruptions. A loss of our information technology systems, or temporary interruptions in the operation of our information technology systems, misappropriation of data, and breaches of security could have a material adverse effect on our business, financial condition, results of operations, and reputation. In addition, a cyber security attack could provide a cyber intruder with the ability to control or alter our pipeline operations. Such an act could result in critical pipeline failures.

In response to natural gas explosions in the United States, regulators may adopt new laws or reinterpret existing laws and regulations relating to the replacement of cast iron and bare steel natural gas pipelines which may adversely affect our results of operations and cash flows.

New federal or state laws may be adopted, or state and/or federal regulatory agencies, such as the PUC and United States Department of Transportation, may reinterpret existing laws and regulations relating to the timing of the replacement of cast iron and bare steel natural gas pipelines by all natural gas distribution and transmission companies under their respective jurisdictions. If the Company is required to comply with new or changed laws and regulations or the Company is not permitted to charge increased rates to recover a mandated increase in our costs, our cash flows and earnings may decrease.

Our operations, capital expenditures and financial results may be affected by regulatory changes and/or market responses to global climate change.

There continues to be concern, both nationally and internationally, about climate change and the contribution of greenhouse gas (“GHG”) emissions, most notably carbon dioxide, to global warming. In addition to carbon dioxide, greenhouse gases include, among others, methane, a component of natural gas. While some states have adopted laws and regulations regulating the emission of GHGs for some industry sectors, there is currently no federal or regional legislation mandating the reduction of GHG emissions in the United States. Although Congress has not enacted federal climate change legislation, the Environmental Protection Agency (“EPA”) has begun adopting and implementing regulations to restrict emissions of GHGs from motor vehicles and certain large stationary sources, and to require reporting of GHG emissions by certain regulated facilities on an annual basis. Increased regulation of GHG emissions could impose significant additional costs on us, our suppliers, and our customers. In September 2009, the EPA issued a final rule establishing a system for mandatory reporting of GHG emissions. In November 2010, the EPA expanded the reach of its GHG reporting requirements to include the petroleum and natural gas industries. Petroleum and natural gas facilities subject to the rule, which include facilities of our natural gas distribution business, were required to begin emissions monitoring in January 2011 and to submit detailed annual reports beginning in March 2012. The rule does not require affected facilities to implement GHG emission controls or reductions. However, in August 2015, the EPA finalized the Clean Power Plan rule, which provides standards and guidelines for reducing existing power plants’ GHG emissions and related pollutants by 2030. Under the Clean Power Plan’s standards and guidelines, existing power plants will be required to reduce emissions through a rate-based or a mass-based approach; states will begin submitting their reduction plans to the EPA in September 2016. The impact of such legislation and regulations will depend on a number of factors, including (i) what industry sectors would be impacted, (ii) the timing of required compliance, (iii) the overall GHG emissions cap level, (iv) the allocation of emission allowances to specific sources and (v) the costs and opportunities associated with compliance. At this time, we cannot predict the effect that climate change regulation may have on our business, financial condition or results of operations in the future.

Remediation costs resulting from liability from contamination claims could reduce our net income.

We have received claims from third parties that allege that we are responsible for costs to clean up properties where we or our former subsidiaries operated a manufactured gas plant or conducted other operations. Costs we incur at sites outside of Pennsylvania cannot be recovered in future UGI Utilities' rate proceedings, and insurance may not cover all or even part of these costs. Our actual costs related to these sites may exceed our current estimates due to factors beyond our control, such as:

- the discovery of presently unknown conditions;
- changes in environmental laws and regulations;
- judicial rejection of our legal defenses to the third-party claims; or
- the insolvency of other responsible parties at the sites at which we are involved.

In addition, if we discover additional contaminated sites, we could be required to incur material costs, which would reduce our net income.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

With the exception of those matters set forth in Note 12 to Consolidated Financial Statements included in Item 8 of this Report, no material legal proceedings are pending involving the Company, or any of its properties, and no such proceedings are known to be contemplated by governmental authorities other than claims arising in the ordinary course of the Company's business.

ITEM 4. MINE SAFETY DISCLOSURES

None.

PART II:

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

All of the outstanding shares of the Company's Common Stock are owned by UGI and are not publicly traded.

Dividends

Cash dividends declared on the Company's Common Stock totaled $65.6 million in Fiscal 2015, $77.4 million in Fiscal 2014, and $59.0 million in Fiscal 2013.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") discusses our results of operations and our financial condition. MD&A should be read in conjunction with our Items 1 & 2, "Business and Properties," Item 1A, "Risk Factors" and our Consolidated Financial Statements in Item 8 below including "Segment Information" included in Note 16 to Consolidated Financial Statements.

EXECUTIVE OVERVIEW

Our results in Fiscal 2015 reflect temperatures based upon heating degree days in our Gas Utility service territory that were 5.9% colder than normal but 3.7% warmer than in Fiscal 2014. Gas Utility continued to benefit from strong demand for natural gas service across its residential and commercial customer classes. Notwithstanding the headwinds from a significant drop in oil prices during Fiscal 2015, Gas Utility experienced another strong year of customer growth with customer additions, largely the result of conversions from other fuels, only slightly below the record levels experienced in Fiscal 2014.

Our net income in Fiscal 2015 was $121.1 million, a decrease of $3.0 million (2.5%) from Fiscal 2014 net income of $124.1 million. The slightly lower results in Fiscal 2015 at our Gas Utility principally reflect higher operating, administrative and depreciation expenses partially offset by a slight increase in total margin. Our Electric Utility's kilowatt-hour sales in Fiscal 2015 were higher than the prior year as lower heating-related sales from warmer heating-season weather was more than offset by higher summer air-conditioning sales. Electric Utility incurred slightly lower operating and administrative expenses during Fiscal 2015.

In Fiscal 2015, Gas Utility capital expenditures for customer growth and infrastructure upgrades and replacements were higher than in Fiscal 2014. We anticipate that Gas Utility infrastructure capital expenditures will continue at historically high levels in Fiscal 2016, and we will likely begin to execute on a multi-year, multi-phase information technology initiative that will update and enhance UGI Utilities' portfolio of technology applications including, among other things, new customer information, work management and infrastructure management systems. This major IT project is expected to span a number of years and result in enhanced business processes throughout the organization.

We believe that we have sufficient liquidity in the forms of cash generated from operations and our revolving credit facility to fund business operations in Fiscal 2016. In addition, we expect to issue long-term debt in Fiscal 2016 and beyond in order to refinance maturing long-term debt as well as to help finance the growth in Gas Utility maintenance capital and our information technology initiatives.

ANALYSIS OF RESULTS OF OPERATIONS

The following analyses compare the Company's results of operations for Fiscal 2015, Fiscal 2014 and the year ended September 30, 2013 ("Fiscal 2013").

Fiscal 2015 Compared with Fiscal 2014

(Millions of dollars)	2015	2014	Increase (Decrease)	
Gas Utility:				
Revenues	$ 933.1	$ 977.3	$ (44.2)	(4.5)%
Total margin (a)	$ 484.5	$ 480.6	$ 3.9	0.8 %
Operating income	$ 226.5	$ 236.2	$ (9.7)	(4.1)%
Income before income taxes	$ 187.4	$ 199.6	$ (12.2)	(6.1)%
System throughput — bcf				
Core market	81.3	80.4	0.9	1.1 %
Total	213.5	208.8	4.7	2.3 %
Degree days — % colder than normal (b)	5.9%	10.0%	—	—
Electric Utility:				
Revenues	$ 107.6	$ 108.1	$ (0.5)	(0.5)%
Total margin (a)	$ 39.8	$ 36.0	$ 3.8	10.6 %
Operating income	$ 14.2	$ 9.7	$ 4.5	46.4 %
Income before income taxes	$ 12.1	$ 7.8	$ 4.3	55.1 %
Distribution sales — gwh	1,010.1	987.3	22.8	2.3 %

bcf — billions of cubic feet.

gwh — millions of kilowatt-hours.

(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 $5.6 million and $5.8 million during Fiscal 2015 and Fiscal 2014, respectively. For financial statement purposes, revenue-related taxes are included in taxes other than income taxes in the 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 Fiscal 2015 based upon heating degree days were 5.9% colder than normal but 3.7% warmer than in Fiscal 2014. Total distribution system throughput increased 4.7 bcf, notwithstanding the warmer weather, principally reflecting higher large firm delivery service volumes and slightly higher core market volumes reflecting, in large part, a 1.9% year-over-year 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 $44.2 million in Fiscal 2015 principally reflecting lower revenues from off-system sales ($31.8 million) and lower revenues from core market customers ($7.6 million). The decrease in core market revenues principally reflects the effects of lower average PGC rates during Fiscal 2015 partially offset by the slightly higher core market throughput. 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 $448.6 million in Fiscal 2015 compared with $496.8 million in Fiscal 2014 principally reflecting the effects of the lower off-system sales ($31.8 million) and the effects on retail core-market cost of sales of the lower average PGC rates partially offset by slightly higher retail core-market throughput.

Fiscal 2015 Gas Utility total margin increased $3.9 million principally reflecting higher core market total margin ($4.0 million) on the higher core market sales and higher large firm delivery service total margin ($5.7 million). These increases were partially offset principally by lower margin from interruptible customers ($7.0 million).

Gas Utility operating income and income before income taxes during Fiscal 2015 decreased $9.7 million and $12.2 million, respectively. The $9.7 million decrease in Gas Utility operating income, notwithstanding the $3.9 million increase in total margin, principally reflects higher operating and administrative expenses and higher depreciation expense partially offset by an increase in other operating income. Fiscal 2015 operating and administrative expenses were $13.1 million higher than in Fiscal 2014 principally reflecting, among other things, higher Fiscal 2015 distribution system expenses ($4.8 million), and higher employee benefits, uncollectible accounts and other general administrative expenses. Gas Utility depreciation expense increased $4.1 million reflecting the effects of greater distribution system capital expenditures. Other operating income increased $3.4 million reflecting, among other things, incremental income from construction services. The $12.2 million decrease in Gas Utility income before income taxes reflects the lower operating income ($9.7 million) and higher long-term debt interest expense.

Electric Utility. Temperatures based upon heating degree days during Fiscal 2015 were approximately 1.5% colder than normal and approximately 4.7% warmer than the prior year. Total kilowatt-hour sales increased by 2.3% as lower sales resulting from heating season weather that was approximately 4.7% warmer than in Fiscal 2014 was more than offset by the effects of a warmer summer on air-conditioning sales. The $0.5 million decrease in Electric Utility revenues primarily reflects lower average Default Service ("DS") rates partially offset by higher transmission revenue. Electric Utility cost of sales decreased to $62.2 million in Fiscal 2015 from $66.2 million in Fiscal 2014 principally reflecting the effects of the lower average DS rates.

Fiscal 2015 Electric Utility total margin, net of gross receipts taxes, increased $3.8 million principally reflecting an increase in transmission revenue including a $1.6 million recovery of transmission revenues primarily associated with prior years. Electric Utility operating income and income before income taxes in Fiscal 2015 increased $4.5 million and $4.3 million, respectively, principally reflecting the increase in total margin and lower Fiscal 2015 operating and administrative expenses including lower distribution and uncollectible accounts expense.

Interest Expense and Income Taxes. Our interest expense in Fiscal 2015 was higher than in Fiscal 2014 principally reflecting interest on the 4.98% Senior Notes which were 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 in Fiscal 2015 was slightly lower than in the prior year.

Fiscal 2014 Compared with Fiscal 2013

(Millions of dollars)	2014	2013	Increase (Decrease)	
Gas Utility:				
Revenues	$ 977.3	$ 839.1	$ 138.2	16.5 %
Total margin (a)	$ 480.6	$ 431.8	$ 48.8	11.3 %
Operating income	$ 236.2	$ 198.4	$ 37.8	19.1 %
Income before income taxes	$ 199.6	$ 161.1	$ 38.5	23.9 %
System throughput — bcf				
Core market	80.4	70.6	9.8	13.9 %
Total	208.8	192.1	16.7	8.7 %
Degree days —% colder (warmer) than normal (b)	10.0%	(0.5)%	—	—
Electric Utility:				
Revenues	$ 108.1	$ 100.0	$ 8.1	8.1 %
Total margin (a)	$ 36.0	$ 35.8	$ 0.2	0.6 %
Operating income	$ 9.7	$ 11.4	$ (1.7)	(14.9)%
Income before income taxes	$ 7.8	$ 9.4	$ (1.6)	(17.0)%
Distribution sales — gwh	987.3	992.6	(5.3)	(0.5)%

(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 $5.8 million and $5.4

million during Fiscal 2014 and Fiscal 2013, respectively. For financial statement purposes, revenue-related taxes are included in taxes other than income taxes in the 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 Fiscal 2014 based upon heating degree days were 10.0% colder than normal and 10.6% colder than Fiscal 2013. Total distribution system throughput increased 16.7 bcf principally reflecting a 9.8 bcf (13.9%) increase in demand from Gas Utility's core market customers and, to a lesser extent, greater net large firm and interruptible delivery service volumes. Gas Utility system throughput to core market customers was higher than last year principally reflecting the effects of the significantly colder weather and, to a lesser extent, customer growth due principally to conversions from other fuels prompted by sustained lower natural gas prices relative to heating oil prices.

Gas Utility revenues increased $138.2 million during Fiscal 2014 principally reflecting higher revenues from core market customers ($83.6 million), higher revenues from off-system sales ($36.4 million) and, to a much lesser extent, higher revenues from large firm delivery service customers on higher throughput ($12.5 million). The increase in core market revenues principally reflects the effects of the higher core market throughput. 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. Gas Utility's cost of sales were $496.8 million in Fiscal 2014 compared with $407.2 million in Fiscal 2013 principally reflecting the effects of the greater retail core-market volumes sold ($50.1 million) and the effects of the higher off-system sales ($36.4 million).

Gas Utility total margin increased $48.8 million in Fiscal 2014 principally reflecting higher core market total margin ($33.8 million) and greater large firm delivery service total margin ($10.8 million). The higher core market and large firm delivery service total margin reflects the effects of the previously mentioned colder weather and customer growth.

Gas Utility operating income and income before income taxes during Fiscal 2014 increased $37.8 million and $38.5 million, respectively, over Fiscal 2013. The increase in Gas Utility operating income principally reflects the $48.8 million increase in total margin partially offset by higher operating and administrative expenses. Operating and administrative expenses in Fiscal 2014 were modestly higher than the prior year principally reflecting greater Fiscal 2014 distribution system maintenance expenses ($5.3 million), higher uncollectible accounts expense ($3.0 million) and greater incentive compensation expense partially offset by lower pension expense. The increase in Gas Utility income before income taxes reflects the greater operating income ($37.8 million) and slightly lower interest expense.

Electric Utility. Temperatures based upon heating degree days during Fiscal 2014 were approximately 6.6% colder than normal and approximately 8.5% colder than the prior year. The increase in Electric Utility revenues primarily reflects higher average DS rates. Electric Utility cost of sales increased to $66.2 million in Fiscal 2014 from $58.8 million in Fiscal 2013 principally reflecting the effects of the greater DS rates.

Electric Utility total margin was about equal to the prior year. Operating income and income before income taxes in Fiscal 2014 decreased $1.7 million and $1.6 million, respectively, principally reflecting higher distribution system maintenance costs resulting from Fiscal 2014 summer storm damage and slightly higher uncollectible accounts expense.

Interest Expense and Income Taxes. Our interest expense in Fiscal 2014 was slightly lower than the prior year principally reflecting lower average interest rates. Our effective income tax rate in Fiscal 2014 was comparable with the prior year.

FINANCIAL CONDITION AND LIQUIDITY

Capitalization and Liquidity

UGI Utilities' total debt outstanding was $693.7 million at September 30, 2015, which includes $71.7 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. UGI Utilities' total long-term debt outstanding at September 30, 2015, comprises $450.0 million of Senior Notes and $172.0 million of Medium-Term Notes.

In March 2015, UGI Utilities entered into an unsecured credit agreement (the "Credit Agreement") with a group of banks providing for borrowings of up to $300 million (including a $100 million sublimit for letters of credit) which expires in March 2020. Concurrently with entering into the Credit Agreement, UGI Utilities terminated its then-existing $300 million revolving credit agreement dated as of May 25, 2011. Borrowings under the Credit Agreement and the predecessor credit agreement are classified as short-term borrowings on the Consolidated Balance Sheets. During Fiscal 2015 and Fiscal 2014, average daily short-term borrowings under the credit agreements were $61.7 million and $29.9 million, respectively, and peak short-term borrowings totaled

$163.6 million and $86.3 million, respectively. Peak short-term borrowings typically occur during the heating season months of December and January when UGI Utilities' investment in working capital, principally accounts receivable and inventories, is generally greatest. The Credit Agreement requires UGI Utilities to not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined. UGI Utilities was in compliance with this covenant at September 30, 2015.

Based upon cash expected to be generated from operations, borrowings under the Credit Agreement and the anticipated issuance of long-term debt management believes the Company will be able to meet its anticipated contractual and projected cash commitments during Fiscal 2016. For additional discussion of UGI Utilities' long-term debt and the Credit Agreement, see Note 7 to Consolidated Financial Statements.

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 $306.7 million in Fiscal 2015, $188.7 million in Fiscal 2014 and $169.9 million in Fiscal 2013. The significant increase in cash flow from operating activities in Fiscal 2015 compared with Fiscal 2014 primarily reflects the impact of lower natural gas prices on changes in working capital. Cash provided by operating activities before changes in operating working capital was $229.3 million in Fiscal 2015, $224.6 million in Fiscal 2014 and $196.7 million in Fiscal 2013. The higher cash flow before changes in operating working capital in Fiscal 2014 compared to Fiscal 2013 reflects, in large part, the higher year-over-year operating results. Changes in operating working capital provided (used) $77.4 million of cash in Fiscal 2015, $(35.9) million of cash in Fiscal 2014 and $26.8 million of cash in Fiscal 2013. The significantly higher cash flow from changes in operating working capital in Fiscal 2015 reflects, in large part, the impact of the previously mentioned lower natural gas prices on overcollections of deferred fuel costs and changes in inventories and accounts receivable.

Investing activities. Cash used by investing activities was $216.6 million in Fiscal 2015, $172.8 million in Fiscal 2014, and $159.2 million in Fiscal 2013. The year-over-year increases in capital expenditures during the three-year period principally reflects higher year-over-year Gas Utility capital expenditures for infrastructure replacements, system improvements and customer growth. Fiscal 2015 cash flow from investing activities includes a $3.0 million increase in restricted cash in futures brokerage accounts compared to a $0.4 million increase in Fiscal 2014 and a $3.2 million increase in Fiscal 2013. Changes in restricted cash in futures brokerage accounts are generally the result of changes in underlying commodity prices.

Financing activities. Cash used by financing activities was $99.4 million in Fiscal 2015, $8.2 million in Fiscal 2014 and $7.3 million in Fiscal 2013. Financing activities cash flows are primarily the result of issuances and repayments of long-term debt, revolving credit agreement borrowings and cash dividends to UGI. During Fiscal 2015, net short-term debt repayments totaled $14.6 million compared to net short-term borrowings of $68.8 million in Fiscal 2014 and $8.3 million in Fiscal 2013. The greater repayments in Fiscal 2015 resulted from the significantly higher cash provided by operating activities.

Capital Expenditures

In the following table, we present capital expenditures by business segment for Fiscal 2015, Fiscal 2014 and Fiscal 2013. We also provide amounts we expect to spend in Fiscal 2016. We expect to finance a substantial portion of our Fiscal 2016 capital expenditures from cash generated by operations and borrowings under our Credit Agreement and, to a lesser extent, cash proceeds from issuance of long-term debt expected to occur in Fiscal 2016.

(Millions of dollars)	2016	2015	2014	2013
	(estimate)			
Gas Utility	$ 301.8	$ 189.7	$ 156.4	$ 144.4
Electric Utility	12.1	8.0	7.8	6.7
	$ 313.9	$ 197.7	$ 164.2	$ 151.1

The higher levels of Gas Utility capital expenditures in Fiscal 2015, as well as those estimated for Fiscal 2016, reflect greater main replacement and system improvement capital expenditures, increases in new business capital expenditures and, in Fiscal 2016, expected investments in new information technology projects.

Contractual Cash Obligations and Commitments

UGI Utilities has contractual cash obligations that extend beyond Fiscal 2015, including scheduled repayments of long-term debt and interest, operating lease obligations, unconditional purchase obligations for pipeline transportation and natural gas storage services, commitments to purchase natural gas and electricity and derivative financial instruments. The following table presents significant contractual cash obligations under agreements existing as of September 30, 2015:

	Payments Due by Period				
(Millions of dollars)	Total	Fiscal 2016	Fiscal 2017 - 2018	Fiscal 2019 - 2020	Thereafter
Long-term debt (a)	$ 622.0	$ 247.0	$ 60.0	$ —	$ 315.0
Interest on long-term fixed rate debt (b)	451.9	33.4	40.2	34.9	343.4
Derivative financial instruments (c)	12.6	12.6	—	—	—
Operating leases	17.8	6.4	8.7	2.2	0.5
Gas Utility and Electric Utility supply, storage and transportation contracts	636.1	204.9	206.0	131.6	93.6
Total	$ 1,740.4	$ 504.3	$ 314.9	$ 168.7	$ 752.5

(a) Based upon stated maturity dates.
(b) Based upon stated interest rates.
(c) Represents sum of amounts due from us if derivative financial instruments were settled at the September 30, 2015, amounts reflected in the Consolidated Balance Sheet.

The components of the other noncurrent liabilities included in our Consolidated Balance Sheet at September 30, 2015, principally consist of pension and other postretirement benefit liabilities recorded in accordance with GAAP and estimated obligations for environmental investigation and remediation. These liabilities are not included in the table of Contractual Cash Obligations and Commitments above because they are estimates of future payments and not contractually fixed as to timing or amount. We believe the minimum required contributions to our pension plan in Fiscal 2016 are not expected to be material. Contributions to the pension plan in years beyond Fiscal 2016 will depend in large part on the effects of future returns and interest rates on pension plan assets. For additional information on these liabilities see Notes 9 and 12 to Consolidated Financial Statements.

Pension Plan

UGI Utilities has a defined benefit pension plan covering employees hired prior to January 1, 2009, of UGI, UGI Utilities, PNG, CPG and certain of UGI's other domestic wholly owned subsidiaries (the "Pension Plan").

The fair values of the Pension Plan's assets totaled $430.8 million and $442.5 million at September 30, 2015 and 2014, respectively. At September 30, 2015 and 2014, the underfunded positions of the Pension Plan, defined as the excess of the projected benefit obligations ("PBOs") over the Pension Plan's assets, were $132.8 million and $97.3 million, respectively.

We believe we are in compliance with regulations governing defined benefit pension plans, including Employee Retirement Income Security Act of 1974 ("ERISA") rules and regulations. Required minimum contributions to the U.S. Pension Plan in Fiscal 2016 are not expected to be material. Pre-tax pension cost associated with the Pension Plan in Fiscal 2015 was $9.7 million. Pre-tax pension cost associated with Pension Plan in Fiscal 2016 is expected to be approximately $11.5 million.

Generally accepted accounting principles ("GAAP") guidance associated with pension and other postretirement plans generally requires recognition of an asset or liability in the statement of financial position reflecting the funded status of pension and other postretirement benefit plans with current year changes recognized in shareholder's equity unless such amounts are subject to regulatory recovery. Through September 30, 2015, we have recorded cumulative after-tax charges to stockholder's equity of $9.3 million and regulatory assets of $140.8 million in order to reflect the funded status of our pension and postretirement benefit plans. For a more detailed discussion of the Pension Plans and other postretirement benefit plans, see Note 9 to Consolidated Financial Statements.

REGULATORY MATTERS

Growth Extension Tariff. On February 20, 2014, the PUC entered an order approving a Growth Extension Tariff (“GET Gas”) program under which UGI Gas, PNG and CPG may invest up to $5 million per year for five years to extend natural gas utility pipelines to provide service to unserved and underserved areas within their respective territories. Under the GET Gas program, customers utilizing the extended pipeline to receive natural gas will pay a monthly surcharge over a 10-year period to cover the cost of the extension. UGI Gas, PNG, and CPG began connecting customers under the GET Gas program in October 2014.

Distribution System Improvement Charge. On April 14, 2012, legislation became effective enabling gas and electric utilities in Pennsylvania, under certain circumstances, to recover the cost of eligible capital investment in distribution system infrastructure improvement projects between base rate cases. The charge enabled by the legislation is known as a distribution system improvement charge (“DSIC”). The primary benefit to a company from a DSIC charge is the elimination of regulatory lag, or delayed rate recognition, that occurs under traditional ratemaking relating to qualifying capital expenditures. To be eligible for a DSIC, a utility must have filed a general rate filing within five years of its petition seeking permission to include a DSIC in its tariff, and not exceed certain earnings tests. Absent PUC permission, the DSIC is capped at five percent of the amount billed to customers. PNG and CPG received PUC approval on a DSIC tariff, initially set at zero, in 2014, while UGI Gas has not had a general rate filing within the required time period to be eligible. Beginning on April 1, 2015, PNG was able to begin charging a DSIC at a rate other than zero. The impact of the DSIC charge at PNG did not have a material effect on Gas Utility results of operations.

MANUFACTURED GAS PLANTS

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 $1.8 million and $1.1 million, 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 September 30, 2015 and 2014, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $13.8 million and $10.7 million, respectively. In accordance with GAAP related to rate-regulated entities, we have recorded associated regulatory assets in equal amounts.

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 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 receive ratemaking recognition of environmental investigation and remediation costs associated with their environmental sites. This ratemaking recognition balances the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites. At September 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.

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 Consolidated Statements of Income. In addition, UGI Utilities provides limited administrative services to UGI and certain of UGI's subsidiaries. Amounts billed to these entities by UGI Utilities for all periods presented were not material.

UGI Utilities is a party to Storage Contract Administration Agreements ("SCAAs") with Energy Services. At September 30, 2015, UGI Utilities was a party to two SCAAs with Energy Services, both of which expired October 31, 2015, and, during the periods covered by the financial statements, was a party to other SCAAs with Energy Services. Under the SCAAs, UGI Utilities has, among other things, and subject to recall for operational purposes, released certain storage and transportation contracts to Energy Services for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon the commencement of the SCAAs, receives a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the term of the SCAAs. Energy Services, in turn, provides a firm delivery service and makes certain payments to UGI Utilities for its various obligations under the SCAAs. UGI Utilities incurred costs associated with Energy Services' SCAAs totaling $16.8, $38.3 and $45.8 in Fiscal 2015, Fiscal 2014 and Fiscal 2013, respectively. In conjunction with the SCAAs, UGI Utilities received security deposits from Energy Services. The amounts of such security deposits, which are included in other current liabilities on the Consolidated Balance Sheets, were $10.7 and $10.6 at September 30, 2015 and 2014, respectively. Effective November 1, 2015, UGI Utilities entered into a new SCAA with Energy Services having a term of three years.

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 values of these gas storage inventories at September 30, 2015 and 2014, comprising approximately 5.0 bcf and 7.7 bcf of natural gas, were $12.9 million and $33.1 million, 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 during the heating season months of November through March. The aggregate amount of these transactions (exclusive of transactions pursuant to the SCAAs) during Fiscal 2015, Fiscal 2014 and Fiscal 2013 totaled $47.8 million, $35.8 million and $32.5 million, respectively.

From time to time, the Company sells natural gas or pipeline capacity to Energy Services. During Fiscal 2015, Fiscal 2014 and Fiscal 2013, revenues associated with sales to Energy Services totaled $79.2 million, $109.9 million and $69.1 million, 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 Fiscal 2015, Fiscal 2014 and Fiscal 2013, such purchases totaled $85.4 million, $128.1 million and $77.0 million, respectively. These transactions did not have a material effect on the Company's financial position, results of operations or cash flows.

OFF-BALANCE-SHEET ARRANGEMENTS

We do not have any off-balance-sheet arrangements that are expected to have an effect on the Company's financial condition, revenues and expenses, results of operations, liquidity, capital expenditures or capital resources.

MARKET RISK DISCLOSURES

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 New York Mercantile Exchange ("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 September 30, 2015, Gas Utility had $6.6 million of restricted cash associated with futures accounts with brokers. At September 30, 2014, Gas Utility had $3.6 million of restricted cash in brokerage accounts. At September 30, 2015 and 2014, the fair values of our natural gas futures and option contracts were losses of $3.3 million and $1.4 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 financial transmission rights ("FTRs") and forward electricity purchase contracts, associated with our Electric Utility operations. At September 30, 2015 and 2014, the fair values of Electric Utility's electricity supply contracts recorded at fair value were (losses) gains of $(0.5) million and $0.3 million, respectively. The fair values of FTRs at September 30, 2015 and 2014, 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 operating expenses and other income. The amount of unrealized gains on these contracts and associated volumes under contract at September 30, 2015 and 2014, were not material.

Interest Rate Risk

We have both fixed-rate debt and variable rate debt. Changes in interest rates impact the cash flows of variable-rate debt but generally do not impact their fair value. Conversely, changes in interest rates impact the fair value of fixed-rate debt but do not impact their cash flows.

Our variable-rate debt comprises borrowings under our Credit Agreement. This agreement provides for interest rates on borrowings that are indexed to short-term market interest rates. Based upon the average level of borrowings outstanding under these agreements in Fiscal 2015 and Fiscal 2014, an increase in short-term interest rates of 100 basis points (1%) would have increased annual interest expense by $0.6 million and $0.3 million, respectively.

Our long-term debt is typically issued at fixed rates of interest based upon market rates for debt having similar terms and credit ratings. As these long-term debt issues mature, we expect to refinance such debt with new debt having interest rates reflecting then-current market conditions. A 100 basis point increase in market interest rates would result in decreases in the fair value of this fixed-rate debt of approximately $50.0 million and $53.0 million at September 30, 2015 and 2014, respectively. A 100 basis point decrease in market interest rates would result in increases in the fair value of this fixed-rate debt of approximately $60.0 million and $64.0 million at September 30, 2015 and 2014, respectively.

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 interest rate protection agreements ("IRPAs"). The fair values of unsettled IRPAs held at September 30, 2015 were losses of$7.0 million. A 50 basis point decline in interest rates would result in an approximate $23.5 million decline in the fair values of our IRPAs at September 30, 2015. There were no unsettled IRPAs outstanding at September 30, 2014.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Accounting policies and estimates discussed in this section are those that we consider to be the most critical to an understanding of our financial statements because they involve significant judgments and uncertainties. Changes in these policies and estimates could have a material effect on the financial statements. The application of these accounting policies and estimates necessarily requires management's most subjective or complex judgments regarding estimates and projected outcomes of future events which could have a material impact on the financial statements. Management has reviewed these critical accounting policies, and the estimates and assumptions associated with them, with the Company's Audit Committee. In addition, management has reviewed the following disclosures regarding the application of these critical accounting policies and estimates with the Audit Committee. Also, see Note 2 to Consolidated Financial Statements, Summary of Significant Accounting Policies, which discusses the significant accounting policies that we have selected from acceptable alternatives.

Impairment of Goodwill. Our goodwill is the result of Gas Utility business acquisitions. We do not amortize goodwill, but test it at least annually for impairment at the reporting unit level. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by segment management. Components are aggregated as a single reporting unit if they have similar economic characteristics. In accordance with GAAP, a reporting unit with goodwill is required to perform an impairment test annually or whenever events or circumstances indicate that the value of goodwill may be impaired. We are required to recognize an impairment charge under GAAP if the carrying amount of a reporting unit exceeds its fair value and the carrying amount of the reporting unit's goodwill exceeds the implied fair value of that goodwill as determined in the same manner as goodwill is recognized in a business combination. We determine the fair value of our Gas Utility generally based on a weighting of income and market approaches. For purposes of the income approach, fair values are determined based upon the present value of the reporting unit's estimated future cash flows, including an estimate of the reporting unit's terminal value based upon these cash flows, discounted at appropriate risk-adjusted rates. We use our internal forecasts to estimate future cash flows which may include estimates of long-term future growth rates based upon our most recent reviews of the long-term outlook for each reporting unit. Cash flow estimates used to establish fair values under our income approach involve management judgments based on a broad range of information and historical results. In addition, external economic and competitive conditions can influence future performance. For purposes of the market approach, we use valuation multiples for companies comparable to the reporting unit. The market approach requires judgment to determine the appropriate valuation multiples. Under certain circumstances, the Company may perform a qualitative approach to determine if it is not more likely than not that the carrying value of a reporting unit is greater than its fair value. As of September 30, 2015, our goodwill totaled $182.1 million. We did not record any impairments of goodwill during Fiscal 2015, Fiscal 2014 or Fiscal 2013.

Litigation Accruals and Environmental Remediation Liabilities. We are involved in litigation regarding pending claims and legal actions that arise in the normal course of our businesses. In addition, UGI Utilities and its former subsidiaries owned and operated a number of MGPs in Pennsylvania and elsewhere and PNG and CPG owned and operated a number of MGP sites located in Pennsylvania, at which hazardous substances may be present. In accordance with GAAP, we establish reserves for pending claims and legal actions or environmental remediation obligations when it is probable that a liability exists and the amount or range of amounts can be reasonably estimated. Reasonable estimates involve management judgments based on a broad range of information and prior experience. These judgments are reviewed quarterly as more information is received and the amounts reserved are updated as necessary. Such estimated reserves may differ materially from the actual liability and such reserves may change materially as more information becomes available and estimated reserves are adjusted.

Depreciation of Property, Plant and Equipment. We compute depreciation on UGI Utilities property, plant and equipment on a straight-line basis over the average remaining lives of its various classes of depreciable property. Changes in the estimated useful lives of property, plant and equipment could have a material effect on our results of operations. As of September 30, 2015, UGI Utilities net property, plant and equipment totaled $1,824.4 million and we recorded depreciation expense of $59.8 million during Fiscal 2015.

Regulatory Assets and Liabilities. Gas Utility and Electric Utility are subject to regulation by the PUC. In accordance with accounting guidance associated with rate-regulated entities, we record the effects of rate regulation in our financial statements as regulatory assets or regulatory liabilities. We continually assess whether the regulatory assets are probable of future recovery by evaluating the regulatory environment, recent rate orders and public statements issued by the PUC, and the status of any pending deregulation legislation. If future recovery of regulatory assets ceases to be probable, the elimination of those regulatory assets would adversely impact our results of operations and cash flows. As of September 30, 2015, our regulatory assets and regulatory liabilities totaled $304.2 million and $71.0 million, respectively. For additional information on our regulatory assets and liabilities, see Note 2 and Note 4 to Consolidated Financial Statements.

Pension Plan Assumptions. Pension plan assumptions are significant inputs to the actuarial models that measure pension benefit obligations and pension expense. The cost of providing benefits under the Pension Plan is dependent on historical information such as employee age, length of service, level of compensation and the actual rate of return on plan assets. In addition, certain assumptions relating to the future are used to determine pension expense including mortality assumptions, the discount rate applied to benefit obligations, the expected rate of return on plan assets and the rate of compensation increase, among others. In October 2014, the Society of Actuaries developed an updated set of mortality assumptions presented in its RP-2014 Mortality Tables Report. During Fiscal 2015, we undertook a review of our Pension Plan mortality assumptions in light of the RP-2014 Mortality Tables Report. Based upon such review, we believe that the RP-2014 Mortality Table, adjusted for UGI's own experience and reflecting a blue-collar adjustment, with future improvements using the IRS scale BB-2D, represents the best estimate of future mortality improvement for the Pension Plan. The new mortality assumptions increased the September 30, 2015, Pension Plan PBO by less than 5%, and we expect the new mortality assumptions will have the effect of increasing Pension Plan expense in Fiscal 2016 by approximately $3.5 million. Assets of the Pension Plan are held in trust and consist principally of equity and fixed income mutual funds and common stock. Changes in plan assumptions as well as fluctuations in actual equity or fixed income market returns could have a material impact on future pension costs. We believe the two most critical assumptions are (1) the expected rate of return on plan assets and (2) the discount rate. A decrease in the expected rate of return on Pension Plan assets of 50 basis points to a rate of 7.05% would result in an increase in pre-tax pension cost of approximately $2.0 million in Fiscal 2016. A decrease in the discount rate of 50 basis points to a rate of 4.10% would result in an increase in pre-tax pension cost of approximately $3.4 million in Fiscal 2016. For additional information on our Pension Plan, see Note 9 to Consolidated Financial Statements.

Purchase Price Allocations. In the event that the Company enters into a material business combination, in accordance with accounting guidance associated with business combinations, the purchase price is allocated to the various assets and liabilities acquired at their estimated fair value. Fair values of assets acquired and liabilities assumed are based upon available information and we may involve an independent third-party to perform appraisals. Estimating fair values can be complex and subject to significant business judgment and most commonly impacts property, plant and equipment and intangible assets, including those with indefinite lives. Generally, we have, if necessary, up to one year from the acquisition date to finalize the purchase price allocation.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

See Note 3 to Consolidated Financial Statements for a discussion of recently issued accounting guidance.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

"Quantitative and Qualitative Disclosures About Market Risk" are contained in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations under the caption "Market Risk Disclosures" and are incorporated herein by reference.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements and the financial statement schedule referred to in the Index contained on page F-1 of this Report are incorporated herein by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) 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 September 30, 2015, were effective at the reasonable assurance level.

(b) *Management's Annual Report on Internal Control over Financial Reporting*. Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, management has conducted an assessment, including testing, of the Company's internal control over financial reporting as of September 30, 2015, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO 2013 Framework").

Internal control over financial reporting refers to the process, designed under the supervision and participation of management including our Chief Executive Officer and Principal Financial Officer, to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States and includes policies and procedures that, among other things, provide reasonable assurance that assets are safeguarded and that transactions are executed in accordance with management's authorization and are properly recorded to permit the preparation of reliable financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate due to changing conditions, or the degree of compliance with the policies or procedures may deteriorate.

Based on its assessment, management has concluded that the Company's internal control over financial reporting was effective as of September 30, 2015, based on the COSO 2013 Framework. Ernst & Young LLP, our independent registered public accounting firm, has audited the effectiveness of the Company's internal control over financial reporting as of September 30, 2015, as stated in their report, which appears herein.

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

ITEM 9B. OTHER INFORMATION

None.

PART III:

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The aggregate fees billed by Ernst & Young LLP, the Company's independent registered public accounting firm in Fiscal 2015, and PricewaterhouseCoopers LLP, the Company's independent registered public accounting firm in Fiscal 2014, were as follows:

	2015	2014
Audit Fees	$ 840,850	$ 1,070,189
Audit-Related Fees	0	0
Tax Fees	0	0
All Other Fees	0	0
Total Fees for Services Provided	$ 840,850	$ 1,070,189

Consistent with SEC policies regarding auditor independence, the Audit Committee has responsibility for appointing, setting compensation and overseeing the work of the Company's independent accountants. In recognition of this responsibility, the Audit Committee has a policy of pre-approving audit and permissible non-audit services provided by the independent accountants.

Prior to engagement of the Company's independent accountants for the next year's audit, management submits a list of services and related fees expected to be rendered during that year within each of the four categories of services noted above to the Audit Committee for approval.

PART IV:

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of this report:

(1) Financial Statements:

Included under Item 8 are the following financial statements and supplementary data:

Report of Independent Registered Public Accounting Firm (on Internal Control over Financial Reporting) - Ernst & Young LLP

Report of Independent Registered Public Accounting Firm (on Consolidated Financial Statements and Schedule) - Ernst & Young LLP

Report of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP

Consolidated Balance Sheets as of September 30, 2015 and 2014

Consolidated Statements of Income for the fiscal years ended September 30, 2015, 2014 and 2013

Consolidated Statements of Comprehensive Income for the years ended September 30, 2015, 2014 and 2013

Consolidated Statements of Cash Flows for the fiscal years ended September 30, 2015, 2014 and 2013

Consolidated Statements of Stockholder's Equity for the fiscal years ended September 30, 2015, 2014 and 2013

Notes to Consolidated Financial Statements

(2) Financial Statement Schedule:

For the years ended September 30, 2015, 2014 and 2013

II — Valuation and Qualifying Accounts

We have omitted all other financial statement schedules because the required information is (1) not present; (2) not present in amounts sufficient to require submission of the schedule; or (3) included elsewhere in the financial statements or notes thereto contained in this Report.

(3) List of Exhibits:

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Incorporation by Reference

Exhibit No.	Exhibit	Registrant	Filing	Exhibit
3.1	UGI Utilities' Amended and Restated Articles of Incorporation.	Utilities	Registration Statement No. 333-72540 (10/31/01)	3
3.2	Bylaws of UGI Utilities as amended through September 30, 2003.	Utilities	Form 10-K (9/30/03)	3.2
4	Instruments defining the rights of security holders, including indentures. (The Company agrees to furnish to the Commission upon request a copy of any instrument defining the rights of holders of its long-term debt not required to be filed pursuant to the description of Exhibit 4 contained in Item 601 of Regulation S-K).			
4.1	UGI Utilities' Articles of Incorporation and Bylaws referred to in Exhibit Nos. 3.1 and 3.2.			
4.2	Indenture, dated as of August 1, 1993, by and between UGI Utilities, Inc., as Issuer, and U.S. Bank National Association, as successor trustee, incorporated by reference to the Registration Statement on Form S-3 filed on April 8, 1994.	Utilities	Registration Statement No. 33-77514 (4/8/94)	4(c)
4.3	Supplemental Indenture, dated as of September 15, 2006, by and between UGI Utilities, Inc., as Issuer, and U.S. Bank National Association, successor trustee to Wachovia Bank, National Association.	Utilities	Form 8-K (9/12/06)	4.2
4.4	Form of Fixed Rate Medium-Term Note.	Utilities	Form 8-K (8/26/94)	(4)i
4.5	Form of Fixed Rate Series B Medium-Term Note.	Utilities	Form 8-K (8/1/96)	4(i)
4.6	Form of Floating Rate Series B Medium-Term Note.	Utilities	Form 8-K (8/1/96)	4(ii)
4.7	Officer's Certificate establishing Medium-Term Notes Series.	Utilities	Form 8-K (8/26/94)	4(iv)
4.8	Form of Officer's Certificate establishing Series B Medium-Term Notes under the Indenture.	Utilities	Form 8-K (8/1/96)	4(iv)
4.9	Form of Officers' Certificate establishing Series C Medium-Term Notes under the Indenture.	Utilities	Form 8-K (5/21/02)	4.2
4.10	Forms of Floating Rate and Fixed Rate Series C Medium-Term Notes.	Utilities	Form 8-K (5/21/02)	4.1
4.11	Form of Note Purchase Agreement dated October 30, 2013 between the Company and the purchasers listed as signatories thereto.	Utilities	Form 8-K (10/30/13)	4.1

		Incorporation by Reference		
Exhibit No.	**Exhibit**	**Registrant**	**Filing**	**Exhibit**
10.1**	UGI Corporation 2004 Omnibus Equity Compensation Plan Amended and Restated as of December 5, 2006.	UGI	Form 8-K (2/27/07)	10.1
10.2**	UGI Corporation 2004 Omnibus Equity Compensation Plan Amended and Restated as of December 5, 2006 - Terms and Conditions as amended and restated effective November, 2012.	UGI	Form 10-K (9/30/13)	10.2
10.3**	UGI Corporation 2013 Omnibus Incentive Compensation Plan, effective as of January 24, 2013.	UGI	Registration Statement No. 333-186178 (1/24/2013)	99.1
10.4**	UGI Corporation 2009 Deferral Plan, as Amended and Restated effective January 24, 2014.	UGI	Form 10-Q (3/31/14)	10.5
10.5**	UGI Corporation Senior Executive Employee Severance Plan, as amended and restated as of November 16, 2012.	UGI	Form 10-Q (6/30/13)	10.1
10.6**	UGI Corporation Supplemental Executive Retirement Plan and Supplemental Savings Plan, as Amended and Restated effective November 22, 2013.	UGI	Form 10-Q (3/31/14)	10.3
10.7**	UGI Corporation 2009 Supplemental Executive Retirement Plan for New Employees, as Amended and Restated effective November 22, 2013.	UGI	Form 10-Q (3/31/14)	10.4
10.8**	UGI Utilities, Inc. Senior Executive Employee Severance Plan, as amended and restated as of November 16, 2012.	Utilities	Form 10-Q (6/30/13)	10.1
10.9**	UGI Utilities, Inc. Executive Annual Bonus Plan, effective as of October 1, 2006, as amended as of November 16, 2012.	Utilities	Form 10-Q (3/31/13)	10.2
10.10**	UGI Corporation 2013 Omnibus Incentive Compensation Plan Nonqualified Stock Option Grant Letter for UGI Employees, dated January 1, 2015.	UGI	Form 10-Q (3/31/15)	10.9
10.11**	UGI Corporation 2013 Omnibus Incentive Compensation Plan Nonqualified Stock Option Grant Letter for UGI Utilities Employees, dated January 1, 2015.	Utilities	Form 10-Q (3/31/15)	10.2

		Incorporation by Reference		
Exhibit No.	**Exhibit**	**Registrant**	**Filing**	**Exhibit**
10.12**	UGI Corporation 2013 Omnibus Incentive Compensation Plan, Performance Unit Grant Letter for UGI Employees, dated January 1, 2015.	UGI	Form 10-Q (3/31/15)	10.1
10.13**	UGI Corporation 2013 Omnibus Incentive Compensation Plan, Performance Unit Grant Letter for UGI Utilities Employees, dated January 1, 2015.	Utilities	Form 10-Q (3/31/15)	10.1
10.14**	UGI Corporation Executive Annual Bonus Plan effective as of October 1, 2006, as amended November 16, 2012.	UGI	Form 10-Q (3/31/13)	10.14
10.15	FSS Service Agreement No. 79028 effective as of December 1, 2014 by and between Columbia Gas Transmission, LLC and UGI Utilities, Inc.	Utilities	Form 10-K (9/30/14)	10.16
10.16	SST Service Agreement No. 79133 effective as of December 1, 2014 by and between Columbia Gas Transmission, LLC and UGI Utilities, Inc.	Utilities	Form 10-K (9/30/14)	10.19
10.17	Credit Agreement, dated as of March 27, 2015 among UGI Utilities, Inc., as borrower, PNC Bank, National Association, as administrative agent, Citizens Bank of Pennsylvania, as syndication agent, PNC Capital Markets LLC and Citizens Bank, N.A., as joint lead arrangers and joint bookrunners, and PNC Bank, National Association, Citizens Bank of Pennsylvania, Citibank, N.A., Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, The Bank of New York Mellon, Bank of America, N.A., and the other financial institutions from time to time parties thereto.	Utilities	Form 8-K (3/27/15)	10.1
*10.18	Gas Supply and Delivery Service Agreement between UGI Energy Services, LLC and UGI Penn Natural Gas, Inc., effective November 1, 2015.			

		Incorporation by Reference		
Exhibit No.	**Exhibit**	**Registrant**	**Filing**	**Exhibit**
*12.1	Computation of Ratio of Earnings to Fixed Charges.			
14	Code of Ethics for principal executive, financial and accounting officers.	UGI	Form 10-K (9/30/03)	14
*23.1	Consent of Ernst & Young LLP.			
*23.2	Consent of PricewaterhouseCoopers LLP.			
*31.1	Certification by the Chief Executive Officer relating to the Registrant's Report on Form 10-K for the fiscal year ended September 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-K for the fiscal year ended September 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-K for the fiscal year ended September 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			

*	Filed herewith.

**	As required by Item 15(a)(3), this exhibit is identified as a compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.
Date: November 25, 2015	By: /s/ Kirk R. Oliver
	Kirk R. Oliver
	Vice President - Financial Strategy (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on November 25, 2015 by the following persons on behalf of the Registrant in the capacities indicated.

Signature	Title
/s/ Robert F. Beard Robert F. Beard	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ Kirk R. Oliver Kirk R. Oliver	Vice President — Financial Strategy (Principal Financial Officer)
/s/ Ann P. Kelly Ann P. Kelly	Controller (Principal Accounting Officer)
/s/ Lon R. Greenberg Lon R. Greenberg	Chairman and Director
/s/ John L. Walsh John L. Walsh	Vice Chairman and Director
/s/ M. Shawn Bort M. Shawn Bort	Director
/s/ Richard W. Gochnauer Richard W. Gochnauer	Director
/s/ Frank S. Hermance Frank S. Hermance	Director
/s/ Ernest E. Jones Ernest E. Jones	Director
/s/ Anne Pol Anne Pol	Director
/s/ Marvin O. Schlanger Marvin O. Schlanger	Director
/s/ James B. Stallings, Jr. James B. Stallings, Jr.	Director
/s/ Roger B. Vincent Roger B. Vincent	Director

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

No annual report or proxy material was sent to security holders in Fiscal 2015.

UGI UTILITIES, INC.

FINANCIAL INFORMATION

FOR INCLUSION IN ANNUAL REPORT ON FORM 10-K

YEAR ENDED SEPTEMBER 30, 2015

UGI UTILITIES, INC.

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULE

We have omitted all other financial statement schedules because the required information is either (1) not present; (2) not present in amounts sufficient to require submission of the schedule; or (3) included elsewhere in the financial statements or related notes.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholder of UGI Utilities, Inc.

We have audited UGI Utilities, Inc. and subsidiaries' internal control over financial reporting as of September 30, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). UGI Utilities, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, UGI Utilities, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of September 30, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of UGI Utilities, Inc. and subsidiaries as of September 30, 2015, and the related consolidated statements of income, comprehensive income, stockholder's equity, and cash flows for the year then ended and our report dated November 25, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Philadelphia, Pennsylvania
November 25, 2015

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholder of UGI Utilities, Inc.

We have audited the accompanying consolidated balance sheet of UGI Utilities, Inc. and subsidiaries as of September 30, 2015, and the related consolidated statements of income, comprehensive income, stockholder’s equity and cash flows for the year then ended. Our audit also included the financial statement schedule for the year ended September 30, 2015 listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of UGI Utilities, Inc. and subsidiaries at September 30, 2015, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), UGI Utilities Inc.’s internal control over financial reporting as of September 30, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated November 25, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Philadelphia, Pennsylvania
November 25, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholder of UGI Utilities, Inc.:

In our opinion, the consolidated balance sheet as of September 30, 2014 and the related consolidated statements of income, of comprehensive income, of stockholder’s in equity and of cash flows for each of the two years in the period ended September 30, 2014 present fairly, in all material respects, the financial position of UGI Utilities, Inc. and its subsidiaries at September 30, 2014, and the results of their operations and their cash flows for each of the two years in the period ended September 30, 2014, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the two years in the period ended September 30, 2014 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
November 28, 2014

UGI UTILITIES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Thousands of dollars)

	September 30, 2015	September 30, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,099	$ 12,401
Restricted cash	6,602	3,592
Accounts receivable (less allowances for doubtful accounts of $5,599 and $6,992, respectively)	55,659	65,080
Accounts receivable — related parties	1,271	2,865
Accrued utility revenues	12,051	14,330
Inventories	51,716	95,219
Deferred income taxes	24,694	1,492
Income taxes receivable	10,026	—
Regulatory assets	4,105	13,159
Derivative instruments	934	1,028
Prepaid expenses	9,701	8,788
Other current assets	14,202	9,747
Total current assets	194,060	227,701
Property, plant and equipment	2,753,499	2,568,552
Less accumulated depreciation and amortization	(929,130)	(886,268)
Net property, plant and equipment	1,824,369	1,682,284
Goodwill	182,145	182,145
Regulatory assets	300,103	255,007
Other assets	7,501	7,506
Total assets	$ 2,508,178	$ 2,354,643
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 247,000	$ 20,000
Short-term borrowings	71,700	86,300
Accounts payable — trade	58,135	58,453
Accounts payable — related parties	4,430	11,761
Employee compensation and benefits accrued	14,286	14,647
Interest accrued	8,553	8,908
Customer deposits and advances	41,646	40,401
Derivative instruments	12,591	1,632
Regulatory liability - deferred fuel and power refunds	36,638	306
Other current liabilities	38,780	35,074
Total current liabilities	533,759	277,482
Long-term debt	375,000	622,000
Deferred income taxes	512,497	461,461
Deferred investment tax credits	3,597	3,933
Pension and other postretirement benefit obligations	135,003	98,363
Other noncurrent liabilities	57,702	51,567
Total liabilities	1,617,558	1,514,806
Commitments and contingencies (Note 12)		
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
Additional paid-in capital	471,904	471,071
Retained earnings	372,143	316,688
Accumulated other comprehensive loss	(13,686)	(8,181)
Total common stockholder's equity	890,620	839,837
Total liabilities and stockholder's equity	$ 2,508,178	$ 2,354,643

See accompanying Notes to Consolidated Financial Statements.

UGI UTILITIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Thousands of dollars)

	Year Ended September 30,		
	2015	2014	2013
Revenues	$ 1,041,581	$ 1,086,889	$ 940,712
Costs and expenses:			
Cost of sales — gas, fuel and purchased power (excluding depreciation shown below)	510,784	562,942	465,996
Operating and administrative expenses	206,319	195,408	188,266
Operating and administrative expenses — related parties	11,956	10,671	8,366
Taxes other than income taxes	16,134	16,608	16,877
Depreciation	59,841	55,776	52,298
Amortization	3,749	3,443	3,418
Other income, net	(8,869)	(4,359)	(4,828)
	799,914	840,489	730,393
Operating income	241,667	246,400	210,319
Interest expense	41,128	38,471	39,309
Income before income taxes	200,539	207,929	171,010
Income taxes	79,484	83,823	68,912
Net income	$ 121,055	$ 124,106	$ 102,098

See accompanying Notes to Consolidated Financial Statements.

UGI UTILITIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Thousands of dollars)

	Year Ended September 30,		
	2015	2014	2013
Net income	$ 121,055	$ 124,106	$ 102,098
Net (losses) gains on derivative instruments (net of tax of $2,911, $0 and $(10,746), respectively)	(4,105)	—	15,153
Reclassifications of net losses on derivative instruments (net of tax of $(1,109), $(1,112) and $(334), respectively)	1,565	1,567	471
Benefit plans (net of tax of $2,469, $1,002 and $(3,325), respectively)	(3,482)	(1,413)	4,689
Reclassifications of benefit plans actuarial losses and prior service costs (net of tax of $(367), $(274) and $(555), respectively)	517	385	784
Other comprehensive (loss) income	(5,505)	539	21,097
Comprehensive income	$ 115,550	$ 124,645	$ 123,195

See accompanying Notes to Consolidated Financial Statements.

UGI UTILITIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of dollars)

	Year Ended September 30,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 121,055	$ 124,106	$ 102,098
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	63,590	59,219	55,716
Deferred income taxes, net	29,356	33,588	35,281
Pension contributions, net of pension expense	(1,415)	(9,459)	(4,450)
Provision for uncollectible accounts	13,498	13,149	9,584
Other, net	3,228	3,998	(1,560)
Net change in:			
Accounts receivable and accrued utility revenues	7,297	(19,718)	(16,446)
Inventories	43,503	(5,558)	(22,327)
Deferred fuel costs, net of changes in unsettled derivatives	51,778	(17,632)	9,321
Accounts payable	(7,649)	5,757	7,511
Other current assets	(9,723)	362	13,598
Other current liabilities	(7,808)	864	(18,413)
Net cash provided by operating activities	306,710	188,676	169,913
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for property, plant and equipment	(203,192)	(164,180)	(151,090)
Net costs of property, plant and equipment disposals	(10,443)	(8,214)	(4,925)
Increase in restricted cash	(3,010)	(411)	(3,181)
Net cash used by investing activities	(216,645)	(172,805)	(159,196)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payment of dividends	(65,600)	(77,395)	(58,975)
Increase in short-term borrowings	(14,600)	68,800	8,300
Issuances of long-term debt	—	174,445	175,000
Repayments of long-term debt	(20,000)	(175,000)	(133,000)
Excess tax benefits from equity-based payment arrangements	833	973	1,406
Net cash used by financing activities	(99,367)	(8,177)	(7,269)
Cash and cash equivalents (decrease) increase	$ (9,302)	$ 7,694	$ 3,448
CASH AND CASH EQUIVALENTS:			
End of year	$ 3,099	$ 12,401	$ 4,707
Beginning of year	12,401	4,707	1,259
(Decrease) increase	$ (9,302)	$ 7,694	$ 3,448
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for:			
Interest	$ 38,405	$ 34,781	$ 49,460
Income taxes	$ 54,427	$ 54,293	$ 18,376

See accompanying Notes to Consolidated Financial Statements.

UGI UTILITIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDER’S EQUITY
(Thousands of dollars)

	Year Ended September 30,		
	2015	2014	2013
Common stock, without par value			
Balance, beginning of year	$ 60,259	$ 60,259	$ 60,259
Balance, end of year	$ 60,259	$ 60,259	$ 60,259
Retained earnings			
Balance, beginning of year	$ 316,688	$ 269,977	$ 229,379
Net income	121,055	124,106	102,098
Cash dividends — Common Stock	(65,600)	(77,395)	(58,975)
Dividends of net assets	—	—	(2,525)
Balance, end of year	$ 372,143	$ 316,688	$ 269,977
Additional paid-in capital			
Balance, beginning of year	$ 471,071	$ 470,098	$ 468,692
Excess tax benefits on equity-based compensation	833	973	1,406
Balance, end of year	$ 471,904	$ 471,071	$ 470,098
Accumulated other comprehensive income (loss)			
Balance, beginning of year	$ (8,181)	$ (8,720)	$ (29,817)
Net (losses) gains on derivative instruments	(4,105)	—	15,153
Reclassifications of net losses on derivative instruments	1,565	1,567	471
Benefit plans, principally actuarial (losses) gains	(3,482)	(1,413)	4,689
Reclassifications of benefit plans actuarial losses and prior service costs	517	385	784
Balance, end of year	$ (13,686)	$ (8,181)	$ (8,720)
Total UGI Utilities, Inc. stockholder’s equity	$ 890,620	$ 839,837	$ 791,614

See accompanying Notes to Consolidated Financial Statements.

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 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

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.

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

Principles of Consolidation

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

Effects of Regulation

UGI Utilities accounts for the financial effects of regulation in accordance with the Financial Accounting Standards Board's ("FASB's") guidance in Accounting Standards Codification ("ASC") 980 related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that would otherwise be charged to expense are capitalized and recorded as regulatory assets when it is probable that the incurred costs or estimated future expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for expenditures that have not yet been incurred. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to that item will be recovered or refunded within a year of the balance sheet date. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulator. For additional information regarding the effects of rate regulation on our utility operations, see Note 4.

Fair Value Measurements

The Company applies fair value measurements on a recurring and, as otherwise required under GAAP, also on a nonrecurring basis. Fair value measurements performed on a recurring basis principally relate to derivative instruments.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). A level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

We use the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1 — Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.
- Level 2 — Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means.
- Level 3 — Unobservable inputs for the asset or liability including situations where there is little, if any, market activity for the asset or liability.

Fair value is based upon assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and risks inherent in valuation techniques and inputs to valuations. This includes not only the credit standing of counterparties and credit enhancements but also the impact of our own nonperformance risk on our liabilities. We evaluate the need for credit adjustments to our derivative instrument fair values. These credit adjustments were not material to the fair values of our derivative instruments.

Derivative Instruments

Derivative instruments are reported in the Consolidated Balance Sheets at their fair values, unless the derivative instruments qualify for the normal purchase and normal sale (“NPNS”) exception under GAAP and such exception has been elected. The accounting for changes in fair value depends upon the purpose of the derivative instrument and whether it is subject to regulatory ratemaking mechanisms or is designated and qualifies for hedge accounting.

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

For a more detailed description of the derivative instruments we use, our accounting for derivatives, our objectives for using them and other information, see Note 14.

Revenue Recognition

UGI Utilities’ regulated revenues are recognized as natural gas and electricity are delivered and include estimated amounts for distribution service and commodities rendered but not billed at the end of each month. We reflect the impact of Gas Utility and Electric Utility rate increases or decreases at the time they become effective. Nonregulated revenues are recognized as services are performed or products are delivered.

We present revenue-related taxes collected on behalf of customers and remitted to taxing authorities, principally sales and use taxes, on a net basis. Electric Utility gross receipts taxes are included in total revenues in accordance with regulatory practice.

Accounts Receivable

Accounts receivable are reported on the Consolidated Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts. Accounts receivable that are acquired are initially recorded at fair value on the date of acquisition. Provisions for uncollectible accounts are established based upon our collection experience and the assessment of the collectability of specific amounts. Accounts receivable are written off in the period in which the receivable is deemed uncollectible.

Income Taxes

We record deferred income taxes in the Consolidated Statements of Income resulting from the use of accelerated depreciation methods based upon amounts recognized for ratemaking purposes. We also record a deferred tax liability for tax benefits, principally the result of accelerated tax depreciation for state income tax purposes, that are flowed through to ratepayers when temporary differences originate and record a regulatory income tax asset for the probable increase in future revenues that will result when the temporary differences reverse.

We are amortizing deferred investment tax credits related to Utilities' plant additions over the service lives of the related property. Utilities reduces its deferred income tax liability for the future tax benefits that will occur when the deferred investment tax credits, which are not taxable, are amortized. We also reduce the regulatory income tax asset for the probable reduction in future revenues that will result when such deferred investment tax credits amortize.

We join with UGI and its subsidiaries in filing a consolidated federal income tax return. We are charged or credited for our share of current taxes resulting from the effects of our transactions in the UGI consolidated federal income tax return including giving effect to intercompany transactions. The result of this allocation is generally consistent with income taxes calculated on a separate return basis. We record interest on tax deficiencies and income tax penalties in income taxes on the Consolidated Statements of Income.

Cash and Cash Equivalents

All highly liquid investments with maturities of three months or less when purchased are classified as cash equivalents.

Restricted Cash

Restricted cash represents those cash balances in our commodity futures brokerage accounts that are restricted from withdrawal.

Inventories

At September 30, 2015, our inventories are stated at the lower of cost or net realizable value and, prior to September 30, 2015, the lower of cost or market. We determine cost using an average cost method for substantially all of our inventory. During the fourth quarter of Fiscal 2015, the Company adopted new accounting guidance regarding the measurement of inventory which simplified the determination of market value. The adoption of the new guidance did not impact the valuation of our inventories (see Note 3).

Property, Plant and Equipment and Related Depreciation

We record property, plant and equipment at original cost. The amounts assigned to property, plant and equipment of acquired businesses are based upon estimated fair value at date of acquisition.

We record depreciation expense for Utilities' plant and equipment on a straight-line basis over the estimated average remaining lives of the various classes of its depreciable property. The composite annual rate for depreciable property at our Gas Utility was 2.2% in Fiscal 2015, 2.3% in Fiscal 2014 and 2.3% in Fiscal 2013. The composite annual rate for depreciable property at our Electric Utility was 2.5% in Fiscal 2015, 2.5% in Fiscal 2014 and 2.4% in Fiscal 2013. When Utilities retires depreciable utility plant and equipment, we charge the original cost to accumulated depreciation for financial accounting purposes. Costs incurred to retire utility plant and equipment, net of salvage, are recorded in regulatory assets and amortized over 5 years, consistent with the recovery period approved by the PUC.

We include in property, plant and equipment costs associated with computer software we develop or obtain for use in our businesses. We amortize computer software costs on a straight-line basis over expected periods of benefit not exceeding fifteen years once the installed software is ready for its intended use.

No depreciation expense is included in cost of sales in the Consolidated Statements of Income.

Goodwill

Our goodwill is the result of Gas Utility business acquisitions. We do not amortize goodwill, but test it at least annually for impairment at the reporting unit level. A reporting unit is the operating segment, or a business one level below the operating segment (a component) if discrete financial information is prepared and regularly reviewed by segment management. Components are aggregated as a single reporting unit if they have similar economic characteristics. In accordance with GAAP, a reporting unit with goodwill is required to perform an impairment test annually or whenever events or circumstances indicate that the value of goodwill may be impaired. We are required to recognize an impairment charge under GAAP if the carrying amount of a reporting unit exceeds its fair value and the carrying amount of the reporting unit’s goodwill exceeds the implied fair value of that goodwill. We determine the fair value of our Gas Utility generally based on a weighting of income and market approaches. For purposes of the income approach, fair value is determined based upon the present value of the reporting unit’s estimated future cash flows, including an estimate of the reporting unit’s terminal value based upon these cash flows, discounted at appropriate risk-adjusted rates. We use our internal forecasts to estimate future cash flows which may include estimates of long-term future growth rates based upon our most recent reviews of the long-term outlook for the reporting unit. Cash flow estimates used to establish fair values under our income approach involve management judgments based on a broad range of information and historical results. In addition, external economic and competitive conditions can influence future performance. For purposes of the market approach, we use valuation multiples for companies comparable to our reporting unit. The market approach requires judgment to determine the appropriate valuation multiple. Under certain circumstances, the Company may perform a qualitative approach to determine if it is more likely than not that the carrying value of a reporting unit is greater than its fair value. No provisions for goodwill impairments were recorded during Fiscal 2015, Fiscal 2014 or Fiscal 2013.

Impairment of Long-Lived Assets

We evaluate the impairment of long-lived assets whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. We evaluate recoverability based upon undiscounted future cash flows expected to be generated by such assets. No provisions for impairments were recorded during Fiscal 2015, Fiscal 2014 or Fiscal 2013.

Employee Retirement Plans

We use a market-related value of plan assets and an expected long-term rate of return to determine the expected return on assets of our pension and other postretirement plans. The market-related value of plan assets, other than equity investments, is based upon fair values. The market-related value of equity investments is calculated by rolling forward the prior-year’s market-related value with contributions, disbursements and the expected return on plan assets. One third of the difference between the expected and the actual value is then added to or subtracted from the expected value to determine the new market-related value (see Note 9).

Equity-Based Compensation

All of our equity-based compensation, principally comprising UGI stock options and grants of UGI stock-based equity instruments (“Units”), is measured at fair value on the grant date, date of modification or end of the period, as applicable. Compensation expense is recognized on a straight-line basis over the requisite service period. Depending upon the settlement terms of the awards, equity-based compensation costs are measured based upon the fair value of the award on the date of grant or the fair value of the award as of the end of each reporting period. For additional information on our equity-based compensation plans and related disclosures, see Note 11.

Environmental Matters

We are subject to environmental laws and regulations intended to mitigate or remove the effects of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current or former operating sites.

Environmental reserves are accrued when assessments indicate that it is probable that a liability has been incurred and an amount can reasonably be estimated. Amounts recorded as environmental liabilities on the balance sheets represent our best estimate of costs expected to be incurred or, if no best estimate can be made, the minimum liability associated with a range of expected environmental investigation and remediation costs. Our estimated liability for environmental contamination is reduced to reflect anticipated participation of other responsible parties but is not reduced for possible recovery from insurance carriers. In those instances for which the amount and timing of cash payments associated with environmental investigation and cleanup are reliably determinable, we discount such liabilities to reflect the time value of money. We intend to pursue recovery of incurred costs through all appropriate means, including regulatory relief. UGI Gas is permitted to amortize as removal costs site-specific environmental investigation and remediation costs, net of related third-party payments, associated with Pennsylvania sites. UGI Gas is currently permitted to include in rates, through future base rate proceedings, a five-year average of such prudently incurred remediation costs. CPG and PNG receive ratemaking recognition of environmental investigation and remediation costs associated with their environmental sites. This ratemaking recognition balances the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites. For further information, see Note 12.

3. ACCOUNTING CHANGES

Adoption of New Accounting Standard

Measurement of Inventory. During the fourth quarter of Fiscal 2015, the Company adopted new accounting guidance regarding the measurement of inventory. The new guidance amends existing guidance and requires inventory be measured at the lower of cost or net realizable value. Net realizable value is generally defined as estimated selling prices in the ordinary course of business less reasonably predictable costs of completion, disposal and transportation. We applied this guidance prospectively and the adoption of this guidance did not impact our results of operations, cash flows or financial position for Fiscal 2015.

Accounting Standards Not Yet Adopted

Presentation of Deferred Taxes. In November 2015, the FASB issued Accounting Standards Update (“ASU”) No. 2015-17, "Balance Sheet Classification of Deferred Taxes." This ASU amends existing guidance to require that deferred income tax liabilities and assets be classified as noncurrent in a classified balance sheet, and eliminates the prior guidance which required an entity to separate deferred tax liabilities and assets into a current amount and a noncurrent amount in a classified balance sheet. The amendments in this ASU are effective for annual reporting periods beginning after December 15, 2016 (Fiscal 2018), and interim periods within those annual periods. Earlier application is permitted as of the beginning of an interim or annual period. Additionally, the new guidance may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We have not yet selected an adoption method and are currently evaluating the impact of adopting this guidance on our consolidated 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 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 Fiscal 2016. The adoption of the new guidance is not expected to have a material impact on the Company’s financial statements.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers.” This ASU supersedes the revenue recognition requirements in 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 entity 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, 2018 (Fiscal 2019) and allows for either full retrospective adoption or modified retrospective adoption. We have not yet selected a transition method and are currently evaluating the impact of adopting this guidance on our consolidated financial statements.

4. REGULATORY ASSETS AND LIABILITIES AND REGULATORY MATTERS

The following regulatory assets and liabilities associated with Utilities are included in our accompanying Consolidated Balance Sheets at September 30:

	2015	2014
Regulatory assets:		
Income taxes recoverable	$ 115,946	$ 110,709
Underfunded pension and postretirement plans	140,762	110,116
Environmental costs	19,983	14,616
Deferred fuel and power costs	—	11,732
Removal costs, net	21,223	16,790
Other	6,294	4,203
Total regulatory assets	$ 304,208	$ 268,166
Regulatory liabilities (a):		
Postretirement benefits	$ 19,975	$ 18,594
Environmental overcollections	—	349
Deferred fuel and power refunds	36,638	306
State tax benefits — distribution system repairs	13,266	10,076
Other	1,125	3,172
Total regulatory liabilities	$ 71,004	$ 32,497

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

Income taxes recoverable. This regulatory asset is the result of recording deferred tax liabilities pertaining to temporary tax differences principally as a result of the pass through to ratepayers of the tax benefit on accelerated tax depreciation for state income tax purposes, and the flow through of accelerated tax depreciation for federal income tax purposes for certain years prior to 1981. These deferred taxes have been reduced by deferred tax assets pertaining to utility deferred investment tax credits. Utilities has recorded regulatory income tax assets related to these deferred tax liabilities representing future revenues recoverable through the ratemaking process over the average remaining depreciable lives of the associated property ranging from 1 to approximately 65 years.

Underfunded pension and other postretirement plans. This regulatory asset represents the portion of prior service cost and net actuarial losses associated with pension and other postretirement benefits which are probable of being recovered through future rates based upon established regulatory practices. These regulatory assets are adjusted annually or more frequently under certain circumstances when the funded status of the plans is recorded in accordance with GAAP. These costs are amortized over the average remaining future service lives of plan participants.

Environmental costs. Environmental costs represent amounts actually spent by UGI Gas to clean up sites in Pennsylvania as well as the portion of estimated probable future environmental remediation and investigation costs principally at manufactured gas plant (“MGP”) sites that CPG and PNG expect to incur in conjunction with remediation consent orders and agreements with the Pennsylvania Department of Environmental Protection (see Note 12). Consistent with prior ratemaking treatment, UGI Gas anticipates it will recover in rates, through future base rate proceedings, a five-year average of prudently incurred remediation costs at Pennsylvania sites and UGI Gas is currently amortizing such costs over a five-year period. PNG and CPG are currently recovering and expect to continue to recover environmental remediation and investigation costs in base rate revenues. At September 30, 2015, the period over which PNG and CPG expect to recover these costs will depend upon future remediation activity.

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

Gas Utility uses derivative instruments to reduce volatility in the cost of gas it purchases for firm- residential, commercial and industrial ("retail core-market") customers. Realized and unrealized gains or losses on natural gas derivative instruments are included in deferred fuel costs or refunds. Net unrealized losses on such contracts at September 30, 2015 and 2014, were $3,262 and $1,363, respectively.

Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. Prior to March 1, 2015, we did not designate these purchase contracts as NPNS 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 prudently incurred DS costs. At September 30, 2015 and 2014, the fair values of Electric Utility's electricity supply contracts were (losses) gains of $(533) and $345, respectively. These amounts are reflected in current and noncurrent derivative assets and current and noncurrent derivative liabilities on the 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 14).

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 September 30, 2015 and 2014, were not material.

Removal costs, net. This regulatory asset represents costs incurred, net of salvage, associated with the retirement of depreciable utility plant. Consistent with prior ratemaking treatment, UGI Utilities expects to recover these costs over 5 years.

Postretirement benefits. Gas Utility and Electric Utility are recovering ongoing postretirement benefit costs at amounts permitted by the PUC in prior base rate proceedings. With respect to UGI Gas and Electric Utility, the difference between the amounts recovered through rates and the actual costs incurred in accordance with accounting for postretirement benefits are being deferred for future refund to or recovery from ratepayers. Such amounts are reflected in regulatory liabilities in the table above. In addition, this regulatory liability includes the portion of prior service credits and net actuarial gains associated with certain other postretirement benefit plans.

Environmental overcollections. This regulatory liability represents the difference between amounts recovered in rates and actual costs incurred (net of insurance proceeds) associated with the terms of a consent order agreement between CPG and the Pennsylvania Department of Environmental Protection ("DEP") to remediate certain gas plant sites.

State income tax benefits — distribution system repairs. This regulatory liability represents Pennsylvania state income tax benefits, net of federal income tax expense, resulting from the deduction for income tax purposes of repair and maintenance costs associated with Gas Utility or Electric Utility assets which are capitalized for regulatory and GAAP reporting. The tax benefits associated with these repair and maintenance deductions will be reflected as a reduction to income tax expense over the remaining tax lives of the related book assets.

Other. Other regulatory assets and liabilities comprise a number of items including, among others, deferred postretirement costs, deferred asset retirement costs, deferred rate case expenses and customer choice implementation costs. At September 30, 2015, UGI Utilities expects to recover these costs over periods of approximately 1 to 20 years.

UGI Utilities does not recover a rate of return on its regulatory assets.

Other Regulatory Matters

Distribution System Improvement Charge. On April 14, 2012, legislation became effective enabling gas and electric utilities in Pennsylvania, under certain circumstances, to recover the cost of eligible capital investment in distribution system infrastructure improvement projects between base rate cases. The charge enabled by the legislation is known as a distribution system improvement charge ("DSIC"). The primary benefit to a company from a DSIC charge is the elimination of regulatory lag, or delayed rate recognition, that occurs under traditional ratemaking relating to qualifying capital expenditures. To be eligible for a DSIC, a utility must have filed a general rate filing within five years of its petition seeking permission to include a DSIC in its tariff, and not exceed certain earnings tests. Absent PUC permission, the DSIC is capped at five percent of the amount billed to customers. PNG and CPG received PUC approval on a DSIC tariff, initially set at zero, in 2014, while UGI Gas has not had a general rate filing within the required time period to be eligible. Beginning on April 1, 2015, PNG was able to begin charging a DSIC at a rate other than zero. The impact of the DSIC charge at PNG did not have a material effect on Gas Utility results of operations.

5. INVENTORIES

Inventories comprise the following at September 30:

	2015	2014
Gas Utility natural gas	$ 37,510	$ 82,664
Materials, supplies and other	14,206	12,555
Total inventories	$ 51,716	$ 95,219

At September 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 18), 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 September 30, 2015 and 2014, comprising 9.0 billion cubic feet ("bcf") and 11.6 bcf of natural gas, were $22,694 and $49,897, respectively. At September 30, 2015 and 2014, UGI Utilities held a total of $17,700 and $17,600, respectively, of security deposits received from its SCAA counterparties. These amounts are included in other current liabilities on the Consolidated Balance Sheets. Effective November 1, 2015, UGI Utilities entered into a new SCAA with Energy Services which has a term of three years.

For additional information related to the SCAAs with Energy Services, see Note 18.

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment comprise the following categories at September 30:

	2015	2014
Distribution	$ 2,458,080	$ 2,294,590
Transmission	90,036	88,199
General and other, including construction in process	205,383	185,763
Total property, plant and equipment	$ 2,753,499	$ 2,568,552

7. DEBT

Long-term debt comprises the following at September 30:

	2015	2014
Senior Notes:		
5.75%, due September 2016	$ 175,000	$ 175,000
4.98%, due March 2044	175,000	175,000
6.21%, due September 2036	100,000	100,000
Medium-Term Notes:		
5.16%, due May 2015	—	20,000
7.37%, due October 2015	22,000	22,000
5.64%, due December 2015	50,000	50,000
6.17%, due June 2017	20,000	20,000
7.25%, due November 2017	20,000	20,000
5.67%, due January 2018	20,000	20,000
6.50%, due August 2033	20,000	20,000
6.13%, due October 2034	20,000	20,000
Total long-term debt	622,000	642,000
Less: current maturities	(247,000)	(20,000)
Total long-term debt due after one year	$ 375,000	$ 622,000

Principal payments on long-term debt during the next five fiscal years is as follows: $247,000 is due in Fiscal 2016; $20,000 is due in Fiscal 2017; $40,000 is due in Fiscal 2018; $0 is due in Fiscal 2019; and $0 is due in Fiscal 2020.

In March 2014, UGI Utilities issued in a private placement $175,000 of 4.98% Senior Notes due March 2044 (“4.98% Senior Notes”). The 4.98% Senior Notes were issued pursuant to a Note Purchase Agreement dated October 30, 2013, between UGI Utilities and certain note purchasers. The 4.98% Senior Notes are unsecured and rank equally with UGI Utilities’ existing outstanding senior debt. The net proceeds from the sale of the 4.98% Senior Notes were used to repay $175,000 of borrowings under UGI Utilities’ then-existing 364-day Term Loan Credit Agreement.

In March 2015, UGI Utilities entered into an unsecured credit agreement (the “Credit Agreement”) with a group of banks providing for borrowings of up to $300,000 (including a $100,000 sublimit for letters of credit) which expires in March 2020. Concurrently, with entering into the Credit Agreement, UGI Utilities terminated its then-existing $300,000 revolving credit agreement dated as of May 25, 2011. Under the 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. UGI Utilities had borrowings outstanding under the credit agreements, which we classify as short-term borrowings on the Consolidated Balance Sheets, totaling $71,700 and $86,300 at September 30, 2015 and 2014, respectively. The weighted-average interest rates on the credit agreement borrowings at September 30, 2015 and 2014 were 1.07% and 1.03%, respectively. Issued and outstanding letters of credit, which reduce available borrowings under the credit agreements, totaled $2,000 at September 30, 2015 and 2014, respectively.

Restrictive Covenants. The 4.98% Senior Notes include the usual and customary covenants for similar type notes including, among others, maintenance of existence, payment of taxes when due, compliance with laws and maintenance of insurance. The 4.98% Senior Notes also contain restrictive and financial covenants including a requirement that UGI Utilities not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.00.

The UGI Utilities Credit Agreement requires UGI Utilities not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined.

8. INCOME TAXES

The provisions for income taxes consist of the following:

	2015	2014	2013
Current expense:			
Federal	$ 34,990	$ 38,786	$ 21,807
State	15,138	11,449	11,824
Total current expense	50,128	50,235	33,631
Deferred expense (benefit):			
Federal	28,877	29,208	33,349
State	815	4,717	2,274
Investment tax credit amortization	(336)	(337)	(342)
Total income tax expense	$ 79,484	$ 83,823	$ 68,912

A reconciliation from the U.S. federal statutory tax rate to our effective tax rate is as follows:

	2015	2014	2013
U.S. federal statutory tax rate	35.0 %	35.0%	35.0 %
Difference in tax rate due to:			
State income taxes, net of federal	5.1	5.1	5.4
Other, net	(0.5)	0.2	(0.1)
Effective tax rate	39.6 %	40.3%	40.3 %

Pennsylvania utility ratemaking practice permits the flow through to ratepayers of state tax benefits resulting from accelerated tax depreciation. For Fiscal 2015, Fiscal 2014 and Fiscal 2013, the beneficial effects of state tax flow through of accelerated depreciation reduced tax expense by $1,539, $1,976 and $1,538, respectively.

Deferred tax liabilities (assets) comprise the following at September 30:

	2015	2014
Excess book basis over tax basis of property, plant and equipment	$ 431,480	$ 392,839
Goodwill	40,552	36,034
Regulatory assets	117,420	109,953
Other	2,573	1,349
Gross deferred tax liabilities	592,025	540,175
Pension plan liabilities	(54,444)	(40,461)
Allowance for doubtful accounts	(2,809)	(2,903)
Deferred investment tax credits	(1,493)	(1,632)
Employee-related expenses	(5,637)	(5,630)
Regulatory liabilities	(23,958)	(14,836)
Environmental liabilities	(6,014)	(4,389)
Derivative financial instruments	(3,501)	(6,224)
Other	(6,367)	(4,131)
Gross deferred tax assets	(104,223)	(80,206)
Net deferred tax liabilities	$ 487,802	$ 459,969

We join with UGI and its subsidiaries in filing a consolidated federal income tax return. We are charged or credited for our share of current taxes resulting from the effects of our transactions in the UGI consolidated federal income tax return including giving effect to intercompany transactions. UGI's federal income tax returns are settled through the tax year 2011.

We file separate company income tax returns in various other states but are subject to state income tax principally in Pennsylvania. Pennsylvania income tax returns are generally subject to examination for a period of three years after the filing of the respective returns.

During Fiscal 2015, Fiscal 2014 and Fiscal 2013, interest expense of $0, $38 and $0, respectively, was recognized in income taxes in the Consolidated Statements of Income.

A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

	2014	2013
Unrecognized tax benefits - beginning of year	$ 1,087	$ 1,048
Additions for tax positions of prior years	—	39
Settlements with tax authorities	(1,087)	—
Unrecognized tax benefits - end of year	$ —	$ 1,087

There was no activity associated with unrecognized tax benefits during Fiscal 2015.

9. EMPLOYEE RETIREMENT PLANS

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.

The following table provides a reconciliation of the projected benefit obligations ("PBOs") of the Pension Plan, the accumulated benefit obligations ("ABOs") of our other postretirement benefit plans, plan assets and the funded status of the Pension Plan and other postretirement plans as of September 30, 2015 and 2014. ABO is the present value of benefits earned to date with benefits based upon current compensation levels. PBO is ABO increased to reflect future compensation.

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Change in benefit obligations:				
Benefit obligations — beginning of year	$ 539,725	$ 486,468	$ 11,136	$ 10,688
Service cost	7,863	7,309	220	175
Interest cost	24,656	25,102	511	519
Actuarial loss (gain)	14,667	43,064	(835)	205
Benefits paid	(23,290)	(22,218)	(356)	(451)
Benefit obligations — end of year	$ 563,621	$ 539,725	$ 10,676	$ 11,136
Change in plan assets:				
Fair value of plan assets — beginning of year	$ 442,465	$ 398,171	$ 12,848	$ 11,723
Actual gain (loss) on assets	483	47,285	(95)	1,434
Employer contributions	11,131	19,227	126	142
Benefits paid	(23,290)	(22,218)	(356)	(451)
Fair value of plan assets — end of year	$ 430,789	$ 442,465	$ 12,523	$ 12,848
Funded status of the plans — end of year	$ (132,832)	$ (97,260)	$ 1,847	$ 1,712
Assets (liabilities) recorded in the balance sheet:				
Assets in excess of liabilities — included in other noncurrent assets	$ —	$ —	$ 4,011	$ 3,971
Unfunded liabilities — included in other current liabilities	—	(1,100)	—	(159)
Unfunded liabilities — included in other noncurrent liabilities	(132,832)	(96,160)	(2,164)	(2,100)
Net amount recognized	$ (132,832)	$ (97,260)	$ 1,847	$ 1,712
Amounts recorded in stockholder's equity (pre-tax):				
Prior service cost (credit)	$ 178	$ 189	$ (48)	$ (61)
Net actuarial loss (gain)	15,757	10,662	(158)	(46)
Total	$ 15,935	$ 10,851	$ (206)	$ (107)
Amounts recorded in regulatory assets and liabilities (pre-tax):				
Prior service cost (credit)	$ 1,570	$ 1,908	$ (2,890)	$ (3,625)
Net actuarial loss	138,440	107,363	2,289	2,616
Total	$ 140,010	$ 109,271	$ (601)	$ (1,009)

In Fiscal 2016, we estimate that we will amortize approximately $10,625 of net actuarial losses, primarily associated with Pension Plan, and $350 of prior service credits from stockholder's equity and regulatory assets.

Actuarial assumptions are described below. The discount rate assumption was determined by selecting a hypothetical portfolio of high quality corporate bonds appropriate to provide for the projected benefit payments of the Company's postretirement plans. The discount rate was then developed as the single rate that equates the market value of the bonds purchased to the discounted value of the benefit payments. The expected rate of return on assets assumption is based on current and expected asset allocations as well as historical and expected returns on various categories of plan assets as further described below.

	Pension Benefits			Other Postretirement Benefits		
Weighted-average assumptions:	2015	2014	2013	2015	2014	2013
Discount rate - benefit obligations	4.60%	4.60%	5.20%	4.70%	4.60%	5.10% - 5.40%
Discount rate - benefit cost	4.60%	5.20%	4.20%	4.60%	5.10% - 5.40%	4.10% - 4.30%
Expected return on plan assets	7.75%	7.75%	7.75%	5.00%	5.00%	5.00%
Rate of increase in salary levels	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%

The ABOs for the Pension Plan were $523,704 and $499,082 as of September 30, 2015 and 2014, respectively. Included in the end of year Pension Plan PBOs above are $57,595 at September 30, 2015, and $48,758 at September 30, 2014, relating to employees of UGI and certain of its other subsidiaries. Included in the end of year other postretirement plans ABOs above are $863 at September 30, 2015, and $887 at September 30, 2014, relating to employees of UGI and certain of its other subsidiaries.

Net periodic pension and other postretirement benefit costs relating to the Company's employees include the following components:

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Service cost	$ 6,962	$ 6,492	$ 8,211	$ 202	$ 162	$ 205
Interest cost	22,511	22,885	20,783	479	488	557
Expected return on assets	(28,898)	(26,599)	(24,791)	(612)	(557)	(529)
Amortization of:						
Prior service cost (benefit)	348	348	249	(641)	(641)	(420)
Actuarial loss	8,793	6,642	13,463	122	116	336
Net benefit cost (income)	9,716	9,768	17,915	(450)	(432)	149
Change in associated regulatory liabilities	—	—	—	3,740	3,704	3,302
Net benefit cost after change in regulatory liabilities	$ 9,716	$ 9,768	$ 17,915	$ 3,290	$ 3,272	$ 3,451

Pension Plan assets are held in trust and consist principally of publicly traded, diversified equity and fixed income mutual funds and, to a much lesser extent, smallcap common stocks and UGI Corporation Common Stock. It is our general policy to fund amounts for Pension Plan benefits equal to at least the minimum contribution required by ERISA. From time to time we may, at our discretion, contribute additional amounts. During Fiscal 2015, Fiscal 2014 and Fiscal 2013, we made contributions to the Pension Plan of $11,131, $19,227 and $22,365, respectively. The minimum required contributions in Fiscal 2016 are not expected to be material.

UGI Utilities has established a Voluntary Employees' Beneficiary Association ("VEBA") trust to pay retiree health care and life insurance benefits by depositing into the VEBA the annual amount of postretirement benefits costs, if any, determined under GAAP. The difference between such amount and the amounts included in UGI Gas' and Electric Utility's rates is deferred for future recovery from, or refund to, ratepayers. The required contribution to the VEBA during Fiscal 2016, if any, are not expected to be material.

Expected payments for pension and other postretirement welfare benefits are as follows:

	Pension Benefits	Other Postretirement Benefits
Fiscal 2016	$ 24,900	$ 701
Fiscal 2017	26,130	635
Fiscal 2018	27,392	606
Fiscal 2019	28,643	595
Fiscal 2020	29,954	581
Fiscal 2021 - 2025	168,123	2,826

The assumed health care cost trend rates at September 30 are as follows:

	2015	2014
Health care cost trend rate assumed for next year	7.5%	7.0%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.0%	5.0%
Fiscal year that the rate reaches the ultimate trend rate	2026	2019

A one percentage point change in these assumed health care cost trend rates would not have had a material impact on Fiscal 2015 other postretirement benefit cost or the September 30, 2015, other postretirement benefit ABO.

We also sponsor unfunded and non-qualified supplemental executive retirement income plans. At September 30, 2015 and 2014, the PBOs of these plans were $2,835 and $2,866, respectively. We recorded expense for these plans of $445 in Fiscal 2015, $372 in Fiscal 2014 and $498 in Fiscal 2013.

Pension Plan and VEBA Assets. The assets of the Pension Plan and the VEBA are held in trust. The investment policies and asset allocation strategies for the assets in these trusts are determined by an investment committee comprising officers of UGI and UGI Utilities. The overall investment objective of the Pension Plan and the VEBA is to achieve the best long-term rates of return within prudent and reasonable levels of risk. To achieve the stated objective, investments are made principally in publicly traded, diversified equity and fixed income mutual funds and, to a much lesser extent, smallcap common stocks and UGI Common Stock.

The targets, target ranges and actual allocations for the Pension Plan and VEBA trust assets at September 30 are as follows:

	Actual		Target Asset	Permitted
Pension Plan:	2015	2014	Allocation	Range
Equity investments:				
Domestic	56.2%	55.6%	52.5%	40.0% - 65.0%
International	10.2%	11.3%	12.5%	7.5% - 17.5%
Total	66.4%	66.9%	65.0%	60.0% - 70.0%
Fixed income funds & cash equivalents	33.6%	33.1%	35.0%	30.0% - 40.0%
Total	100.0%	100.0%	100.0%	

	Actual		Target Asset	Permitted
VEBA:	2015	2014	Allocation	Range
Domestic equity investments	67.4%	67.9%	65.0%	60.0% - 70.0%
Fixed income funds & cash equivalents	32.6%	32.1%	35.0%	30.0% - 40.0%
Total	100.0%	100.0%	100.0%	

Domestic equity investments include investments in large-cap mutual funds indexed to the S&P 500 and actively managed mid- and small-cap mutual funds, and a self-directed portfolio of small-cap common stocks. Investments in international equity mutual funds seek to track performance of companies primarily in developed markets. The fixed income investments comprise investments designed to match the performance and duration of the Barclays U.S. Aggregate Index. According to statute, the aggregate holdings of all qualifying employer securities may not exceed 10% of the fair value of trust assets at the time of purchase. UGI Common Stock represented 10.1% and 9.6% of Pension Plan assets at September 30, 2015 and 2014, respectively.

The fair values of the Pension Plan and VEBA trust assets are derived from quoted market prices as substantially all of these instruments have active markets. Cash equivalents are valued at the fund's unit net asset value as reported by the trustee. The fair values of the U.S. Pension Plan and VEBA trust assets by asset class and level within the fair value hierarchy, as described in Note 2, as of September 30, 2015 and 2014 are as follows:

	Pension Plan			
	Level 1	Level 2	Level 3	Total
September 30, 2015:				
Domestic equity investments:				
S&P 500 Index equity mutual funds	$ 147,266	$ —	$ —	$ 147,266
Small and midcap equity mutual funds	40,625	—	—	40,625
Smallcap common stocks	10,727	—	—	10,727
UGI Corporation Common Stock	43,419	—	—	43,419
Total domestic equity investments	242,037	—	—	242,037
International index equity mutual funds	43,906	—	—	43,906
Fixed income investments:				
Bond index mutual funds	140,776	—	—	140,776
Cash equivalents	—	4,070	—	4,070
Total fixed income investments	140,776	4,070	—	144,846
Total	$ 426,719	$ 4,070	$ —	$ 430,789
September 30, 2014:				
Equity investments:				
S&P 500 Index equity mutual funds	$ 152,613	$ —	$ —	$ 152,613
Small and midcap equity mutual funds	41,417	—	—	41,417
Smallcap common stocks	9,325	—	—	9,325
UGI Corporation Common Stock	42,502	—	—	42,502
Total domestic equity investments	245,857	—	—	245,857
International index equity mutual funds	49,935	—	—	49,935
Fixed income investments:				
Bond index mutual funds	140,949	—	—	140,949
Cash equivalents	—	5,724	—	5,724
Total fixed income investments	140,949	5,724	—	146,673
Total	$ 436,741	$ 5,724	$ —	$ 442,465

	VEBA			
	Level 1	Level 2	Level 3	Total
September 30, 2015:				
S&P 500 Index equity mutual fund	$ 8,434	$ —	$ —	$ 8,434
Bond index mutual fund	3,832	—	—	3,832
Cash equivalents	—	257	—	257
Total	$ 12,266	$ 257	$ —	$ 12,523
September 30, 2014:				
S&P 500 Index equity mutual fund	$ 8,719	$ —	$ —	$ 8,719
Bond index mutual fund	3,727	—	—	3,727
Cash equivalents	—	402	—	402
Total	$ 12,446	$ 402	$ —	$ 12,848

The expected long-term rates of return on Pension Plan and VEBA trust assets have been developed using a best estimate of expected returns, volatilities and correlations for each asset class. The estimates are based on historical capital market performance data and future expectations provided by independent consultants. Future expectations are determined by using simulations that provide a wide range of scenarios of future market performance. The market conditions in these simulations consider the long-term relationships between equities and fixed income as well as current market conditions at the start of the simulation. The expected rate begins with a risk-free rate of return with other factors being added such as inflation, duration, credit spreads and equity risk premiums. The rates of return derived from this process are applied to our target asset allocation to develop a reasonable return assumption.

Defined Contribution Plan. We sponsor a 401(k) savings plan for eligible employees ("Utilities Savings Plan"). Generally, participants in the Utilities Savings Plan may contribute a portion of their compensation on a before-tax and after-tax basis. The Utilities Savings Plan provides for employer matching contributions. Those employees hired after December 31, 2008, who are not eligible to participate in the Pension Plan, receive employer matching contributions at a higher rate. The cost of benefits under the Utilities Savings Plan totaled $2,162 in Fiscal 2015, $1,916 in Fiscal 2014 and $1,762 in Fiscal 2013. We also sponsor a nonqualified supplemental defined contribution executive retirement plan. This plan generally provides supplemental benefits to certain executives that would otherwise be provided under retirement plans but are prohibited due to limitations imposed by the Internal Revenue Code. Costs associated with this plan were not material in Fiscal 2015, Fiscal 2014 or Fiscal 2013.

10. SERIES PREFERRED STOCK

We have 2,000,000 shares of Series Preferred Stock authorized for issuance, including both series subject to and series not subject to mandatory redemption. We had no shares of Series Preferred Stock outstanding at September 30, 2015 or 2014.

11. EQUITY-BASED COMPENSATION

Under UGI Corporation's 2013 Omnibus Incentive Compensation Plan (the "2013 OICP") and prior UGI equity compensation plans, certain key employees of UGI Utilities may be granted stock options to acquire shares of UGI Common Stock, stock appreciation rights ("SARs"), UGI Units (comprising "Stock Units" and "UGI Performance Units") and other equity-based awards. The exercise price for UGI stock options may not be less than the fair market value on the grant date. Awards granted under the 2013 OICP and the prior plans may vest immediately or ratably over a period of years (generally three-year periods), and stock options for UGI Common Stock can be exercised no later than ten years from the grant date. In addition, the 2013 OICP and the prior UGI equity compensation plans provide that awards of UGI Units may also provide for the crediting of dividend equivalents to participants' accounts. Except in the event of retirement, death or disability, each grant, unless paid, will terminate when the participant ceases to be employed. There are certain change of control and retirement eligibility conditions that, if met, generally result in accelerated vesting or elimination of further service requirements.

UGI Stock Unit and UGI Performance Unit awards entitle the grantee to shares of UGI Common Stock or cash once the service condition is met and, with respect to UGI Performance Unit awards, subject to market performance conditions. UGI Performance Unit grant recipients are awarded a target number of Performance Units. With respect to Performance Units awards, the actual number of UGI shares actually issued (or their cash equivalent) at the end of the performance period and the actual amount of dividend equivalents paid, may range from 0% to 200% of the target award based on UGI's Total Shareholder Return ("TSR") percentile rank relative to (i) companies in the Standard & Poor's Utilities Index for grants prior to January 1, 2011 and (ii) the Russell Midcap Utility Index, excluding telecommunication companies, for grants on or after January 1, 2011 (each a respective "UGI comparator group"). Dividend equivalents are paid in cash only on UGI Performance Units that eventually vest.

We use a Black-Scholes option-pricing model to estimate the fair value of UGI stock options. We use a Monte Carlo valuation approach to estimate the fair value of UGI Performance Unit awards. We recorded total net pre-tax equity-based compensation expense associated with both UGI Units and UGI stock options of $1,847 ($1,081 after-tax) during Fiscal 2015; $1,912 ($1,119 after-tax) during Fiscal 2014; and $1,078 ($631 after-tax) during Fiscal 2013.

As of September 30, 2015, there was $744 of unrecognized compensation cost related to non-vested UGI stock options that is expected to be recognized over a weighted-average period of 1.9 years. As of September 30, 2015, there was a total of $908 of unrecognized compensation expense associated with 60,583 UGI Unit awards that is expected to be recognized over a weighted average period of 1.8 years. At September 30, 2015 and 2014, total liabilities of $1,182 and $1,285, respectively, associated with UGI Unit awards are reflected in other current liabilities and other noncurrent liabilities on the Consolidated Balance Sheets.

The following table summarizes UGI Unit award activity for Fiscal 2015:

	Total		Vested		Non-Vested	
	Number of UGI Units	Weighted Average Grant Date Fair Value (per Unit)	Number of UGI Units	Weighted Average Grant Date Fair Value (per Unit)	Number of UGI Units	Weighted Average Grant Date Fair Value (per Unit)
September 30, 2014	84,522	$ 25.32	24,846	$ 22.52	59,676	$ 26.49
Granted	21,700	$ 38.62	1,858	$ 38.69	19,842	$ 38.61
Vested	—	$ —	20,604	$ 22.40	(20,604)	$ 22.40
Forfeitures & transfers	(13,689)	$ 29.10	—	$ —	(13,689)	$ 29.10
Unit awards paid	(31,950)	$ 20.05	(31,950)	$ 20.05	—	$ —
September 30, 2015	60,583	$ 32.01	15,358	$ 29.46	45,225	$ 32.88

12. COMMITMENTS AND CONTINGENCIES

Commitments

We lease various buildings and vehicles, computer and office equipment and other facilities under operating leases. Certain of our leases contain renewal and purchase options and also contain escalation clauses. Our aggregate rental expense for such leases was $7,956 in Fiscal 2015, $6,803 in Fiscal 2014 and $6,270 in Fiscal 2013.

Minimum future payments under operating leases that have initial or remaining noncancelable terms in excess of one year for the fiscal years ending September 30 are as follows: 2016— $6,438; 2017 — $4,818; 2018 — $3,869; 2019 — $1,621; 2020 — $591; after 2020 — $448.

Gas Utility has gas supply agreements with producers and marketers with terms not exceeding 16 months. Gas Utility also has agreements for firm pipeline transportation, natural gas storage and peaking service which Gas Utility may terminate at various dates through Fiscal 2030. Gas Utility’s costs associated with transportation and storage service agreements are included in its annual PGC filings with the PUC and are recoverable through PGC rates. In addition, Gas Utility has short-term gas supply agreements which permit it to purchase certain of its gas supply needs on a firm or interruptible basis at spot-market prices.

Electric Utility purchases its electricity needs under contracts with various suppliers and on the spot market. Contracts with producers for energy needs expire at various dates through Fiscal 2016.

Future contractual cash obligations under Gas Utility and Electric Utility supply, storage and service agreements existing at September 30, 2015, for fiscal years ending September 30 are as follows: 2016 — $204,881; 2017 — $118,795; 2018 — $87,254; 2019 — $74,621; 2020 — $56,983; after 2020 — $93,596.

Contingencies

Environmental Matters

CPG is party to a Consent Order and Agreement (“CPG-COA”) with the DEP requiring CPG to perform a specified level of activities associated with environmental investigation and remediation work at certain properties in Pennsylvania on which 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 September 30, 2015 and 2014, our accrued liabilities for environmental investigation and remediation costs related to the CPG-COA and the PNG-COA totaled $13,758 and $10,732, 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 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 receive ratemaking recognition of environmental investigation and remediation costs associated with their environmental sites. This ratemaking recognition balances the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites. At September 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.

13. FAIR VALUE MEASUREMENTS

The following table presents, on a gross basis, our financial 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 described in Note 2, as of September 30, 2015 and 2014:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
September 30, 2015				
Derivative instruments:				
Assets:				
Commodity contracts	$ 934	$ 373	$ —	$ 1,307
Liabilities:				
Commodity contracts	$ (4,560)	$ (1,388)	$ —	$ (5,948)
Interest rate contracts	$ —	$ (7,016)	$ —	$ (7,016)
September 30, 2014				
Derivative instruments:				
Assets:				
Commodity contracts	$ 679	$ 1,018	$ —	$ 1,697
Liabilities:				
Commodity contracts	$ (2,095)	$ (206)	$ —	$ (2,301)

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

Other Financial Instruments

The carrying amounts of other financial instruments included in current assets and current liabilities (except for current maturities of long-term debt) approximate their fair values because of their short-term nature. The carrying amount and estimated fair value of our long-term debt (including current maturities) at September 30, 2015, were $622,000 and $681,415, respectively. The carrying amount and estimated fair value of our long-term debt (including current maturities) at September 30, 2014, were $642,000 and $712,815, 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).

14. 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.

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 September 30, 2015 and 2014, the volumes of natural gas associated with Gas Utility’s unsettled NYMEX natural gas futures and option contracts totaled 18.9 million dekatherms and 16.9 million dekatherms, respectively. At September 30, 2015, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 12 months. Gains and losses on natural gas futures contracts and any gains on natural gas option contracts are recorded in regulatory assets or liabilities on the 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 4).

Electric Utility's DS tariffs permit the recovery of all prudently incurred costs of electricity it sells to DS customers, including the cost of financial instruments used to hedge electricity costs. Electric Utility enters into forward electricity purchase contracts to meet a substantial portion of its electricity supply needs. For such contracts entered into prior to March 1, 2015, Electric Utility chose 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 Consolidated Balance Sheets. Associated gains and losses on these forward contracts are recorded in regulatory assets and liabilities on the 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 4). 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 September 30, 2015 and 2014, the volumes of Electric Utility's forward electricity purchase contracts were 331.0 million kilowatt hours and 237.0 million kilowatt hours, respectively. At September 30, 2015, the maximum period over which these contracts extend is 8 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 4). At September 30, 2015 and 2014, the total volumes associated with FTRs totaled 277.1 million kilowatt hours and 232.1 million kilowatt hours, respectively. At September 30, 2015, the maximum period over which we are economically hedging electricity congestion is 8 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 IRPAs. We account for interest rate protection agreements ("IRPAs") as cash flow hedges. As of September 30, 2015, the total notional amounts of our unsettled IRPA contracts was $250,000. At September 30 2014, we had no unsettled IRPAs. Our September 30, 2015, unsettled IRPA contracts hedge forecasted interest payments expected to occur over ten- and thirty-year periods beginning in Fiscal 2016.

At September 30, 2015, the amount of net losses associated with IRPAs expected to be reclassified into earnings during the next twelve months based upon current fair values is $2,463.

Derivative Instrument Credit Risk

Our commodity exchange-traded futures contracts generally require cash deposits in margin accounts. At September 30, 2015, restricted cash in brokerage accounts totaled $6,602. At September 30, 2014, there was $3,592 of restricted cash in brokerage accounts.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities are presented net by counterparty on our 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 Consolidated Balance Sheets with our derivative counterparties are not included in the table below but could reduce our net exposure to such counterparties because such balances are subject to master netting or similar arrangements.

Fair Value of Derivative Instruments

The following table presents our derivative assets and liabilities, as well as the effects of offsetting, as of September 30, 2015 and 2014:

	2015	2014
Derivative assets:		
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	$ 1,307	$ 1,697
Total derivative assets - gross	1,307	1,697
Gross amounts offset in the balance sheet	(373)	(669)
Total derivative assets - net	$ 934	$ 1,028
Derivative liabilities:		
Derivatives designated as hedging instruments:		
Interest rate contracts	$ (7,016)	$ —
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	(5,584)	(2,210)
Derivatives not subject to PGC and DS mechanisms:		
Commodity contracts	(364)	(91)
Total derivative liabilities - gross	(12,964)	(2,301)
Gross amounts offset in the balance sheet	373	669
Total derivative liabilities - net	$ (12,591)	$ (1,632)

Effect of Derivative Instruments

The following table provides information on the effects of derivative instruments not subject to ratemaking mechanisms on the Consolidated Statements of Income and changes in AOCI for Fiscal 2015, Fiscal 2014 and Fiscal 2013:

	Gain (Loss) Recognized in AOCI			Loss Reclassified from AOCI into Income			Location of Loss Reclassified from AOCI into Income
	2015	2014	2013	2015	2014	2013	
Cash Flow Hedges:							
Interest rate contracts	$ (7,016)	$ —	$ 25,898	$ (2,674)	$ (2,679)	$ (805)	Interest expense

	Gain (Loss) Recognized in Income			Location of Gain (Loss) Recognized in Income
	2015	2014	2013	
Derivatives Not Subject to PGC and DS Mechanisms:				
Gasoline contracts	$ (761)	$ —	$ 45	Operating and administrative expenses/other income, net

The amounts of derivative gains and losses on cash flow hedges representing ineffectiveness were not material for all periods presented.

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 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.

15. ACCUMULATED OTHER COMPREHENSIVE INCOME

Other comprehensive income (loss) principally reflects losses on IRPAs qualifying as cash flow hedges and actuarial gains and losses on postretirement benefit plans, net of reclassifications to net income.

Changes in AOCI during Fiscal 2015 and Fiscal 2014 are as follows:

	Postretirement Benefit Plans	Derivative Instruments Net Losses	Total
September 30, 2013	$ (5,283)	$ (3,437)	$ (8,720)
Reclassifications of benefit plan actuarial losses and prior service costs	385	—	385
Reclassifications of net losses on IRPAs	—	1,567	1,567
Benefit plans, principally actuarial losses	(1,413)	—	(1,413)
September 30, 2014	$ (6,311)	$ (1,870)	$ (8,181)
Reclassifications of benefit plan actuarial losses and prior service costs	517	—	517
Reclassifications of net losses on IRPAs	—	1,565	1,565
Net losses on IRPAs	—	(4,105)	(4,105)
Benefit plans, principally actuarial losses	(3,482)	—	(3,482)
September 30, 2015	$ (9,276)	$ (4,410)	$ (13,686)

Amounts in the table above are net of tax.

Reclassifications of net losses on interest rate protection agreements are reflected in interest expense on the Consolidated Statements of Income.

16. 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. 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.

Financial information by business segment follows:

	Total	Gas Utility	Electric Utility	Other
2015				
Revenues	$ 1,041,581	$ 933,080	$ 107,577	$ 924
Cost of sales	$ 510,784	$ 448,617	$ 62,167	$ —
Depreciation and amortization	$ 63,590	$ 58,974	$ 4,616	$ —
Operating income	$ 241,667	$ 226,485	$ 14,153	$ 1,029
Interest expense	$ 41,128	$ 39,112	$ 2,016	$ —
Income before income taxes	$ 200,539	$ 187,373	$ 12,137	$ 1,029
Total assets	$ 2,508,178	$ 2,362,350	$ 145,828	$ —
Goodwill	$ 182,145	$ 182,145	$ —	$ —
Capital expenditures	$ 197,684	$ 189,671	$ 8,013	$ —
2014				
Revenues	$ 1,086,889	$ 977,333	$ 108,072	$ 1,484
Cost of sales	$ 562,942	$ 496,762	$ 66,180	$ —
Depreciation and amortization	$ 59,219	$ 54,816	$ 4,403	$ —
Operating income	$ 246,400	$ 236,219	$ 9,668	$ 513
Interest expense	$ 38,471	$ 36,602	$ 1,869	$ —
Income before income taxes	$ 207,929	$ 199,617	$ 7,799	$ 513
Total assets	$ 2,354,643	$ 2,214,118	$ 140,525	$ —
Goodwill	$ 182,145	$ 182,145	$ —	$ —
Capital expenditures	$ 164,180	$ 156,425	$ 7,755	$ —
2013				
Revenues	$ 940,712	$ 839,050	$ 99,986	$ 1,676
Cost of sales	$ 465,996	$ 407,222	$ 58,774	$ —
Depreciation and amortization	$ 55,716	$ 51,698	$ 4,018	$ —
Operating income	$ 210,319	$ 198,352	$ 11,385	$ 582
Interest expense	$ 39,309	$ 37,280	$ 2,029	$ —
Income before income taxes	$ 171,010	$ 161,072	$ 9,356	$ 582
Total assets	$ 2,210,322	$ 2,068,955	$ 141,367	$ —
Goodwill	$ 182,145	$ 182,145	$ —	$ —
Capital expenditures	$ 151,090	$ 144,399	$ 6,691	$ —

17. OTHER INCOME, NET

Other income, net, comprises the following:

	2015	2014	2013
Non-tariff service income	$ 4,760	$ 2,670	$ 2,706
Construction service income	2,175	—	—
Sale of HVAC Business	1,065	—	—
Interest income	—	1,388	500
Other, net	869	301	1,622
Total other income, net	$ 8,869	$ 4,359	$ 4,828

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

UGI Utilities is a party to SCAAs with Energy Services. At September 30, 2015, UGI Utilities was a party to two SCAAs with Energy Services, both of which expired October 31, 2015, and, during the periods covered by the financial statements, was a party to other SCAAs with Energy Services. Under the SCAAs, UGI Utilities has, among other things, and subject to recall for operational purposes, released certain storage and transportation contracts to Energy Services for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon the commencement of the SCAAs, receives a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the term of the SCAAs. Energy Services, in turn, provides a firm delivery service and makes certain payments to UGI Utilities for its various obligations under the SCAAs. UGI Utilities incurred costs associated with Energy Services' SCAAs totaling $16,849, $38,299 and $45,843 in Fiscal 2015, Fiscal 2014 and Fiscal 2013, 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 Consolidated Balance Sheets, was $10,700 and $10,600 at September 30, 2015 and 2014, respectively. Effective November 1, 2015, UGI Utilities entered into a new SCAA with Energy Services which has a term of three years.

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 September 30, 2015 and 2014, comprising approximately 5.0 bcf and 7.7 bcf of natural gas, were $12,889 and $33,057, respectively.

UGI Utilities has gas supply and delivery service agreements with Energy Services pursuant to which Energy Services provides certain gas supply and related delivery service to Gas Utility primarily during the heating season months of November through March. The aggregate amount of these transactions (exclusive of transactions pursuant to the SCAAs) during Fiscal 2015, Fiscal 2014 and Fiscal 2013 totaled $47,794, $35,810 and $32,526, respectively.

From time to time, the Company sells natural gas or pipeline capacity to Energy Services. During Fiscal 2015, Fiscal 2014 and Fiscal 2013, revenues associated with sales to Energy Services totaled $79,182, $109,913 and $69,087, 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 Fiscal 2015, Fiscal 2014 and Fiscal 2013, such purchases totaled $85,383, $128,076 and $77,017, respectively. These transactions did not have a material effect on the Company's financial position, results of operations or cash flows.

19. QUARTERLY DATA (unaudited)

The following quarterly information includes all adjustments (consisting only of normal recurring adjustments) which we consider necessary for a fair presentation of such information. Quarterly results fluctuate because of the seasonal nature of the Company's businesses.

	December 31,		March 31,		June 30,		September 30,	
	2014	2013	2015	2014	2015	2014	2015	2014
Revenues	$ 287,306	$ 298,899	$ 500,573	$ 513,956	$ 143,490	$ 152,694	$ 110,212	$ 121,340
Operating income	$ 75,640	$ 85,843	$ 142,699	$ 137,954	$ 20,184	$ 19,720	$ 3,144	$ 2,883
Net income (loss)	$ 38,839	$ 45,286	$ 79,589	$ 76,110	$ 7,307	$ 6,890	$ (4,680)	$ (4,180)

UGI UTILITIES, INC. AND SUBSIDIARIES

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

(Thousands of dollars)

	Balance at beginning of year	Charged to costs and expenses	Other	Balance at end of year
September 30, 2015				
Reserves deducted from assets in the consolidated balance sheet:				
Allowance for doubtful accounts	$ 6,992	$ 13,498	$ (14,891) (1)	$ 5,599
September 30, 2014				
Reserves deducted from assets in the consolidated balance sheet:				
Allowance for doubtful accounts	$ 5,519	$ 13,149	$ (11,676) (1)	$ 6,992
September 30, 2013				
Reserves deducted from assets in the consolidated balance sheet:				
Allowance for doubtful accounts	$ 3,588	$ 9,584	$ (7,653) (1)	$ 5,519

(1) Uncollectible accounts written off, net of recoveries

EXHIBIT INDEX

Exhibit No.	Description
10.18	Gas Supply and Delivery Service Agreement between UGI Energy Services, LLC and UGI Penn Natural Gas, Inc., effective November 1, 2015.
12.1	Computation of Ratio of Earnings to Fixed Charges
23.1	Consent of Ernst & Young LLP.
23.2	Consent of PricewaterhouseCoopers LLP.
31.1	Certification by the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act
31.2	Certification by the Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
32	Certification by the Chief Executive Officer and Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act
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

EXHIBIT 10.18

GAS SUPPLY AND DELIVERY SERVICE AGREEMENT

THIS **Gas Supply and Delivery Service Agreement** (“Agreement”) is made and entered into, effective as of November 1, 2015, by and between UGI Penn Natural Gas, Inc., (“Utility”) and UGI Energy Services, Inc. (“UGI ES”) (each referred to herein separately as a “Party” and jointly as the “Parties”).

WHEREAS, Utility is a local distribution company that is principally engaged in the business of distributing natural gas to residential, commercial and industrial end-use customers located within its service territory in Pennsylvania;

WHEREAS, UGI ES is an energy marketer and supplier that is principally engaged in the business of selling natural gas and managing assets for the sale and delivery of natural gas in Pennsylvania and other states; and

WHEREAS, Utility desires to receive, and UGI ES has agreed to provide certain gas supply and related delivery services to Utility, subject to the terms and conditions of this Agreement.

NOW THEREFORE, in consideration of the covenants contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

SECTION 1. Definitions

1.1 “Daily Nomination” shall mean a Nomination made for deliveries during the Delivery Day in accordance with Section 4 hereof.

1.2 “Dekatherm” or **“Dth”** shall mean one million British Thermal Units (MMBtu).

1.3 “Delivery Day” shall mean the day of actual gas flow and delivery applicable to a Nomination. The Parties shall observe the NAESB-defined gas day, which shall be one continuous twenty-four hour period, commencing at 10:00 a.m. ECT.

1.4 “Delivery Point” or **“Delivery Points”** shall mean the point or points of physical interconnection at Transcontinental Pipeline’s (“Transco”) Master Meter No. 1006691, a new interconnection with PNG’s distribution system located in Susquehanna County, PA., or any other mutually agreeable delivery points.

1.5 “Firm” shall mean, in reference to a Party’s obligation to deliver or receive Natural Gas, the requirement that the full quantity of Natural Gas nominated for receipt or delivery must be delivered or received by the obligated Party, except for reasons of Force Majeure under Section 7 or Waiver of Delivery under Section 3.4.

1.6 "Maximum Daily Quantity" or **"MDQ"** shall have the meaning set forth in Section 3.2 hereof.

1.7 "Natural Gas" shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state, including vaporized LNG and propane air.

1.8 "Nomination" shall mean a notice provided by the Utility to UGI ES setting forth its delivery requirements for a Delivery Day, pursuant to Section 4 hereof. The Parties shall maintain 24-hour contacts, seven days per week, for the purposes of providing and receiving Nominations

1.9 "Replacement Supply" shall mean Natural Gas quantities obtained by Utility to replace the portion of a Scheduled Quantity that UGI ES fails to deliver in accordance with a Daily Nomination.

1.10 "Scheduled Quantity" shall mean, for a particular Delivery Day, the quantity of Natural Gas that Utility requests in a Nomination and UGI ES confirms.

1.11 "Winter Season" shall refer to the period beginning at 10:00 a.m. ECT November 1 and ending 9:59 a.m. ECT the following April 1.

SECTION 2. Term

This Agreement shall be effective for a period commencing on and including the Delivery Day of November 1, 2015 and expiring on and including the Delivery Day of March 31, 2022 (the "Primary Term"). Utility shall have the right, in its sole discretion, to extend the Agreement for one or more subsequent years (with each such period referred to as a "Rollover Term") by providing written notice to UGI ES of its intent to extend the Agreement at least sixty days prior to the expiration of the Primary Term or any Rollover Term. If the Utility elects to extend the Agreement for one or more Rollover Terms, the MDQ and all terms and conditions of service shall remain unchanged unless expressly agreed to by the Parties; provided however, that the applicable reservation charge and the commodity charge for the Rollover Term will be adjusted in accordance with Section 5.3 hereof.

SECTION 3. Character of Service

3.1 Delivery Obligation. UGI ES shall sell and deliver and Utility shall have the option to purchase and the right to receive Natural Gas on any day during the winter season. UGI ES's obligation to deliver and Utility's obligation to receive Natural Gas shall be Firm for any Nomination quantity, up to the applicable MDQ. Service will be provided using primary firm pipeline transportation capacity held by UGI ES on Transco and Tennessee, or a reasonably acceptable asset-backed substitute.

3.2 Maximum Daily Quantity. The Maximum Daily Quantity or MDQ shall mean the maximum quantity of Natural Gas that Utility may require UGI ES to deliver on a Firm Basis, on any day during the Primary Term and any Rollover Term. The MDQ during the Primary Term and any Rollover Term shall be the sum of the following:

Winter Season	**MDQ**
November 1 through March 31	Up to 25,875 Dth/day delivered at Utility’s Transco Master Meter No. 1006691
November 1 through March 31	Up to 26, 120 Dth/day delivered at Utility’s distribution system in Susquehanna County, PA

3.3 Authorized Overruns. Utility shall have the right to nominate the higher of 1,000 Dth or 10% of the nominated volumes on an intraday basis including weekends and holidays. The quantity of gas delivered will be prorated based on the time remaining in the gas day.

3.4 Waiver of Delivery Obligation. On any Delivery Day, Utility shall maintain its distribution facilities downstream of the Delivery Point(s) in a way that permits UGI ES to deliver the Scheduled Quantities, otherwise UGI ES shall be relieved of its obligation to deliver the Scheduled Quantities for the period and to the extent that Utility’s distribution facilities do not permit such deliveries. Once the Utility’s distribution facilities have been corrected by Utility, UGI ES shall use commercially reasonable efforts to supply the entire amount nominated by Utility for that Delivery Day.

SECTION 4. Nomination Procedure

Utility may provide UGI ES with a written or verbal Nomination for service on any Delivery Day(s) consistent with the Intercontinental Exchange (“ICE”) trading schedule. Each such Nomination shall specify the Delivery Day and the quantity of Natural Gas required for delivery and the Delivery Point(s).

Utility shall have the right to nominate any quantity up to the MDQ on a month-ahead basis. Utility shall notify UGI ES by 10:00 a.m. two days prior to the expiration for the Henry Hub natural gas futures contract applicable to the month of delivery.

Utility shall have the right to nominate any quantity up to the MDQ on a day-ahead basis. Utility shall notify UGI ES by 9:00 a.m. on the day prior to the NAESB natural gas flow day(s).

Utility shall have the right to nominate the higher of 1,000 Dth or 10% of the nominated volumes on an intraday basis including weekends and holidays. The quantity of gas delivered will be prorated based on the time remaining in the gas day.

SECTION 5. Charges

5.1 Reservation Charge. Utility shall pay UGI ES a reservation charge for each Winter Season during the Primary Term, as follows:

Winter Season	Charge
November 1 through March 31	$6,672,000.00

The reservation charge above shall be paid in five equal installments of $1,334,400.00 due on or before the first of each month during the winter season. The reservation charge shall be billed and paid in accordance with Section 6.

5.2 Commodity Charge. Unless the Utility elects to lock a fixed price with UGI ES in accordance with paragraph (g), below, Utility shall not be obligated to purchase or receive any Natural Gas from UGI ES under this Agreement. For all quantities of Natural Gas sold and delivered by UGI ES, Utility shall pay a commodity charge, which shall be determined pursuant to the following alternatives:

(a) For all quantities up to 25,875 dth per day nominated on a month-ahead basis to PNG's Transco Master Meter, PNG shall pay the published *Platt's Inside FERC* price for Transco Leidy Line Receipts for the month of delivery plus $0.10 plus the applicable Transco maximum tariff rates for fuel and commodity on delivered quantities from Zone 6 to Zone 6.

(b) For all quantities up to 26,120 dth per day nominated on a month-ahead basis to a new interconnection with PNG's distribution system, PNG shall pay the published *Platt's Inside FERC* price for Tennessee Zone 4, 300 leg for the month of delivery plus the applicable Tennessee maximum tariff rates for fuel and commodity on delivered quantities from Zone 4 to Zone 4.

(c) For all quantities up to 25,875 dth per day nominated on a day-ahead basis to PNG's Transco Master Meter, PNG shall pay the published *Platt's Gas Daily* price for Transco Leidy Line Receipts on the day of delivery plus $0.10 plus the applicable Transco maximum tariff rates for fuel and commodity on delivered quantities from Zone 6 to Zone 6.

(d) For all quantities up to 26,120 dth per day nominated on a day-ahead basis to a new interconnection with PNG's distribution system, PNG shall pay the published *Platt's Gas Daily* price for Tennessee Zone 4, 300 leg on the day of delivery plus the applicable Tennessee maximum tariff rates for fuel and commodity on delivered quantities from Zone 4 to Zone 4.

(e) For all quantities up to 25,875 dth per day nominated on an intraday basis to PNG's Transco Master Meter, PNG shall pay the published *Platt's Gas Daily* price for Transco Leidy Line Receipts on the day of delivery plus $0.10 plus the applicable Transco maximum tariff rates for fuel and commodity on delivered quantities from Zone 6 to Zone 6.

(f) For all quantities up to 26,120 dth per day nominated on an intraday basis to a new interconnection with PNG's distribution system, PNG shall pay the published *Platt's Gas Daily price* for Tennessee Zone 4, 300 leg on the day of delivery plus the applicable Tennessee maximum tariff rates for fuel and commodity on delivered quantities from Zone 4 to Zone 4.

(g) Utility shall have the right at any time to lock-in a fixed commodity charge for any term and quantity up to the MDQ throughout the contract term. The commodity charges for locked-in quantities shall be as agreed to by the Parties based on prevailing market conditions at the time the lock-in is made. Utility's right to lock in a quantity of Natural Gas shall be limited as follows:

(i) The maximum quantity of Natural Gas for which the Utility may lock in a fixed commodity charge shall equal the MDQ * number of days remaining in the Winter Season, less any quantities previously locked in for the Winter Season.

(ii) Unless otherwise agreed, Utility shall notify UGI ES of its intention to lock-in the commodity charge by no later than 10:00 a.m. on the last trading day for the NYMEX natural gas contract to the month in which such lock-in will apply. Such notice shall identify the quantity of Natural Gas to be locked in for each month of delivery. UGI ES will promptly communicate to Utility any limitations on the lock-in quantity identified in Utility's notice, and the Parties will utilize commercially reasonable efforts to facilitate the lock in to the extent practicable.

(iii) If Utility has locked in a fixed price, Utility shall be required to purchase and take delivery of the quantity of Natural Gas for which a locked-in price is established.

The commodity charges determined in accordance with sub-paragraphs (a), (b), (c), (d), (e), (f), and (g) above, shall be billed and paid on a monthly basis, in accordance with Section 6.

5.3 Rollover Period Price Adjustment. In the event that Utility elects to extend the agreement for one or more Rollover Terms, the reservation charge applicable to such Rollover Term shall be escalated based on the U.S. Gross Domestic Product Implicit Price Deflator using 2021 as the base. For any subsequent term the escalation fee will be based on the U.S. Gross Domestic Product Implicit Price Deflator using the index from the year prior to the last year of the subsequent term. Unless otherwise locked in accordance with Section 5.2, the commodity charge applicable to the Rollover Term will be equal to the prevailing market price for supply delivered to the Utility's distribution system at the time of delivery. If Utility and UGI ES cannot agree on the market price for supply delivered to the Utility's distribution system, then the commodity charge shall be determined based on the average of up to three quotes received from reference market makers selected mutually by the parties.

SECTION 6. Billing and Payment

UGI ES will invoice Utility each month of the five month winter period for reservation charges and each month for all commodity charges applicable to service rendered during the prior month, plus any applicable taxes in accordance with Section 10 hereto. Utility shall pay UGI ES the full amount due no later than ten (10) days after receipt of such invoice. All payments shall be made by Wire Transfer (EFT) to UGI ES's banking institution, designated as follows:

Mellon Bank, N.A.
Pittsburgh, P A
Account No. XXX-XXXX
ACH No. XXXXXXXXX

SECTION 7. Force Majeure

7.1 Generally. Except as otherwise set forth herein, deliveries under this Agreement shall be Firm, and shall not be subject to curtailment, interruption or proration except as the result of Force Majeure. In the event either UGI ES or Utility is rendered unable, wholly or in part, by a Force Majeure Event to carry out its obligations under this Agreement, it is agreed that upon such Party's giving notice and full particulars of such Force Majeure Event, in accordance with Section 7.3, then the obligations of the Party giving such notice insofar as they are affected by such Force Majeure Event shall be suspended, from the inception, and during the continuance of any inability so caused but for no longer period. Notwithstanding the foregoing, a Party's obligation to pay money when due for service rendered during a prior period shall not be excused as a result of a Force Majeure Event for a period of longer than ten (10) days.

7.2 Included and Excluded Events. Force Majeure shall include, but not be limited to, the following: (i) physical events such as acts of God, landslides, lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe, except as provided in Section 11.3; (ii) interruption and/or curtailment of primary Firm transportation and/or storage by Transporters; (iii) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, terrorist actions, insurrections or wars; and (iv) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.

Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary Firm transportation; (ii) the contractual non-performance or negligence of any affiliate, independent contractor, agent or employee of Seller in operating or maintaining any upstream pipeline facilities utilized by Seller; (iii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; (iv) economic hardship, to include, without limitation, Seller’s ability to sell Gas at a higher or more advantageous price than the Contract Price, Buyer’s ability to purchase Gas at a lower or more advantageous price than the Contract Price, or a regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Agreement; (v) the loss of Buyer’s market(s) or Buyer’s inability to use or resell Gas purchased hereunder, except, in either case, as provided in Section 11.2; or (vi) the loss or failure of Seller’s gas supply, including but not limited to the failure of the Seller’s gas supply to be delivered to an upstream receipt point on Seller’s pipeline capacity, or depletion of reserves, except, in either case, as provided in Section 11.2. In addition to the foregoing, for supplies sourced from local Marcellus production wells, Seller shall not be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (x) any well failures or freeze-offs; and (y) any failure of conditioning equipment such as regulation, compression or dehydration equipment. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.

7.3 Notice. The Party asserting Force Majeure shall provide immediate written notice to the other Party of the occurrence of any Force Majeure Event. Notice shall include (i) a detailed explanation of the event that has occurred, (ii) the known or expected impact on the Party’s ability to perform, and (iii) the period of time during which the Party’s performance will be impacted. The Party asserting Force Majeure will remedy the Force Majeure Event and resume performance of its obligations hereunder as soon as reasonably possible.

SECTION 8. Failure to Deliver or Receive Gas

8.1 Failure to Deliver. Unless otherwise excused by the waiver of a delivery obligation under Section 3.4 or a Force Majeure Event under Section 7.2, if UGI ES fails to deliver all or a portion of a Scheduled Quantity on any Delivery Day, UGI ES shall pay Utility an amount equal to the difference between (i) the Nomination quantity for the Delivery Day and (ii) the quantity delivered during such Delivery Day (such difference being the "Deficiency Amount") times the positive difference between (iii) the applicable commodity charge as determined under Section 5.2 hereof and (iv) the cost of Replacement Supply as determined by Utility in a commercially reasonable manner within a reasonable time after UGI ES fails to deliver the Deficiency Amount.

8.2 Failure to Receive. Unless otherwise excused by the waiver of a delivery obligation under Section 3.4 or a Force Majeure Event under Section 7.2, if Utility fails to take all or a portion of the Scheduled Quantity for the Delivery Day, Utility shall pay UGI ES an amount equal to the "Deficiency Amount" times the positive difference between (i) the applicable commodity charge as determined under Section 5.2 hereof and (ii) the price received by UGI ES from the sale of the Deficiency Amount as determined by UGI ES in a commercially reasonable manner within a reasonable time after the Utility fails to take delivery of the Deficiency Amount.

8.3 Duty to Mitigate. Each Party has an affirmative duty to mitigate in good faith the extent of damages that may arise from the other Party's failure to discharge its receipt or delivery obligations under this Agreement. In the event a Party fails to properly discharge its duty to mitigate, any amounts otherwise due under Sections 8.1 and 8.2 hereunder shall be reduced by an amount that would not have been incurred had such duty been properly discharged.

8.4 Exclusive Remedy. The remedies set forth in Section 8.1 and 8.2 shall be the exclusive remedies available to a party for the other party's failure to discharge its firm receipt or delivery obligation hereunder.

SECTION 9. Indemnification

Except as otherwise limited pursuant to this Agreement, each Party shall indemnify, defend and hold harmless the other Party, the other Party's officers, employees, shareholders, directors, and agents and their respective successors and assigns, from and against any and all third party claims, demands, liabilities, losses, expenses, costs, obligations, recoveries or damages of any nature whatsoever, whether accrued, absolute, contingent or otherwise, including without limitation court costs and attorneys' fees (whether or not suit is brought), arising out of or resulting from or relating to (i) any breach of any of its obligations under this Agreement, (ii) any negligence, gross negligence, bad faith actions, or willful misconduct on its part in connection with this Agreement; and (iii) any Natural Gas while it is in the Party's control or possession; provided however, that a Party's responsibility for such claims and damages under this section shall be limited to the extent that such claims or damages result from the negligence, gross negligence, willful misconduct, or bad faith actions or omissions on the part of the other Party but only to the extent of such actions or omissions. This Section 9 shall survive termination of the Agreement.

SECTION 10. Taxes

10.1 Responsibility. Responsibility for payment of all kinds of taxes applicable to Natural Gas sold hereunder shall be allocated as follows: (a) UGI ES shall pay, or cause to be paid, and Utility shall be held harmless by UGI ES, for the payment of all taxes imposed on or with respect to the Natural Gas sold or delivered hereunder by UGI ES for which the taxable incident arises or occurs prior to delivery of the Natural Gas to the Delivery Point(s); and (b) Utility shall pay or cause to be paid, and UGI ES shall be held harmless by Utility, for the payment of all taxes imposed on or with respect to the Natural Gas sold or delivered by UGI ES hereunder for which the taxable incident arises or occurs upon delivery or after the Natural Gas is delivered to the Delivery Point(s).

10.2 Reimbursement. If a Party is required to remit or pay taxes that are the other Party's responsibility hereunder (including any tax, which would have been incurred by a Party absent this Agreement), the Party responsible for such taxes shall promptly reimburse the other Party therefore.

SECTION 11. Title and Warranties

11.1 Warranty of Title. UGI ES hereby warrants good and merchantable title to the Natural Gas sold by it hereunder or the right to sell the same, and warrants that all Natural Gas shall be delivered to Utility shall be free from all liens, encumbrances, and adverse claims. Upon delivery to Utility, title shall be passed, and shall be deemed to remain with Utility at all times.

11.2 Warranty Disclaimers. Except as expressly stated herein, neither Party provides any warranties to the other, expressed or implied, including the implied warranties of merchantability and fitness for a particular purpose.

SECTION 12. Notices

12.1 Generally. All invoices, payments and other communications made hereunder shall be delivered to the addresses specified in writing by the Parties from time to time.

12.2 Means of Delivery. Unless a specific means of notice is expressly stated herein, all notices required hereunder may be sent by mutually acceptable means, provided, however, that (i) notices shall be deemed given when received on a Business Day by the addressee, (ii) notices sent electronically shall be deemed received upon the sending Party's receipt of its facsimile machine's confirmation of successful transmission, and (iii) any facsimile or other notice received on other than a Business Day or after five p.m. Eastern Clock Time on a Business Day shall be deemed received at the start of the next following Business Day.

12.3 Addresses. Notices shall be provided to the Parties at the following addresses:

If to UGI Energy Services, Inc., to:

UGI Energy Services, Inc.
One Meridian Blvd. Suite 2C01
Wyomissing, PA 19610
Telephone: (610) 373-7999
Facsimile: (61 0) 374-4288
Attention: V.P. Asset and Supply

If to UGI Penn Natural Gas, Inc., to:

UGI Penn Natural Gas, Inc.
2525 North 12th Street, Suite 360
Reading, PA 19677
Telephone: (610) 796-3601
Facsimile: (610) 796-3595
Attention: V.P. Supply

SECTION 13. Assignment

This Agreement shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties; provided, however, that this Agreement shall not be transferred or assigned, by operation of law or otherwise, by UGI ES or Utility without the other Party's prior written consent, which consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, either Party may assign its rights and obligations hereunder to any parent, subsidiary or affiliate, upon prior written notice to the other Party.

SECTION 14. Confidentiality

The existence, terms and conditions of this Agreement shall be and remain confidential to the extent permitted by law.

SECTION 15. **Laws and Regulatory Bodies**

15.1 Generally. This Agreement shall be subject to all valid applicable federal and state laws and to the orders, rules and regulations of any duly constituted federal or state regulatory body or authority having jurisdiction. The interpretation and enforceability of this Agreement shall be governed by the laws of the Commonwealth of Pennsylvania, without recourse to its conflict of law principles.

15.2 Regulatory Event. In the event that any regulatory body directly or indirectly asserts jurisdiction over the Parties' obligations and as a result performance under the Agreement becomes commercially impracticable by either Party ("Regulatory Event"), then the Parties shall negotiate in good faith in order to amend the Agreement (and the Parties' obligations and rights thereunder) to cure the Regulatory Event. In the event the Regulatory Event cannot be reasonably cured to the satisfaction of the affected Party, the Party so affected shall have the right to terminate the Agreement upon thirty (30) days written notice to the other. A regulatory agency disallowing, in whole or in part, the pass through of costs resulting from this Agreement shall not constitute a Regulatory Event.

SECTION 16. **Limitation of Damages**

UNLESS EXPRESSLY PROVIDED HEREIN, A PARTY'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. THIS PARAGRAPH SHALL SURVIVE EXPIRATION OR TERMINATION OF THIS AGREEMENT.

SECTION 17. **Miscellaneous**

17.1 Waiver. No waiver of any breach hereof shall be held to be a waiver of any other or subsequent breach.

17.2 Set-offs. Each Party reserves to itself all rights, set-offs, counterclaims, and other defenses to which it is or may be entitled under applicable law.

17.3 Documentation. Each Party shall provide all documents necessary to effectuate this Agreement and the transactions that underlie this Agreement.

17.4 Amendments. This Agreement, including Appendices hereto, may be amended or modified only by a writing signed by duly authorized representatives of both Parties.

17.5 Authorizations. Utility and UGI ES each represents to the other its respective belief that it has obtained all necessary corporation and regulatory authorizations to execute and perform its obligations under this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate by their respective duly authorized officers as of the day and year first written above.

UGI PENN NATURAL GAS, INC. **UGI ENERGY SERVICES, INC.**

By: /s/ Robert F. Beard By: /s/ Bradley C. Hall
Robert F. Beard Bradley C. Hall
President and CEO President

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

	Year Ended September 30,				
	2015	2014	2013	2012	2011
Earnings:					
Earnings before income taxes	$ 200,539	$ 207,929	$ 171,010	$ 142,971	$ 168,693
Interest expense	40,400	37,897	38,578	41,599	41,668
Amortization of debt discount and expense	728	575	731	814	1,060
Estimated interest component of rental expense	2,728	2,398	2,090	2,121	1,740
	$ 244,395	$ 248,799	$ 212,409	$ 187,505	$ 213,161
Fixed Charges:					
Interest expense	$ 40,400	$ 37,897	$ 38,578	$ 41,599	$ 41,668
Amortization of debt discount and expense	728	575	731	814	1,060
Allowance for funds used during construction (capitalized interest)	407	227	286	10	90
Estimated interest component of rental expense	2,728	2,398	2,090	2,121	1,740
	$ 44,263	$ 41,097	$ 41,685	$ 44,544	$ 44,558
Ratio of earnings to fixed charges	5.52	6.05	5.10	4.21	4.78

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 333-150719) of UGI Utilities, Inc. of our reports dated November 25, 2015, with respect to the consolidated financial statements and schedule of UGI Utilities, Inc., and the effectiveness of internal control over financial reporting of UGI Utilities, Inc., included in this Annual Report (Form 10-K) for the year ended September 30, 2015.

/s/ Ernst & Young LLP
Philadelphia, Pennsylvania
November 25, 2015

EXHIBIT 23.2

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-150719) of UGI Utilities, Inc. of our report dated November 28, 2014 relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
November 25, 2015

EXHIBIT 31.1

CERTIFICATION

I, Robert F. Beard, certify that:

1. I have reviewed this annual report on Form 10-K 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: November 25, 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 annual report on Form 10-K 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: November 25, 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 annual report on Form 10-K for the period ended September 30, 2015 (the “Form 10-K”) 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-K 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: November 25, 2015	Date: November 25, 2015