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, 2018
Commission file number 1-1398

UGI UTILITIES, INC.

(Exact name of registrant as specified in its charter)

Pennsylvania	23-1174060
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

2525 N. 12th Street, Suite 360
Reading, PA 19612
(Address of Principal Executive Offices) (Zip Code)
(610) 796-3400
(Registrant's telephone number, including area code)

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 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

At November 13, 2018, there were 26,781,785 shares of UGI Utilities, Inc. Common Stock, par value $2.25 per share, outstanding, all of which were held, beneficially and of record, by UGI Corporation.

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 our Risk Factors included in Item 1A herein and the following important factors that could affect our future results and could cause those results to differ materially from those expressed in our forward-looking statements: (1) weather conditions resulting in reduced demand; (2) price volatility and availability of electricity and natural gas and the capacity to transport them to market areas; (3) changes in laws and regulations, including safety, tax, consumer protection, environmental, and accounting matters; (4) inability to timely recover costs through utility rate proceedings; (5) the impact of pending and future legal proceedings; (6) competitive pressures from the same and alternative energy sources; (7) liability for environmental claims; (8) customer conservation measures due to high energy prices and improvements in energy efficiency and technology resulting in reduced demand; (9) adverse labor relations; (10) customer, counterparty, supplier, or vendor defaults; (11) increased uncollectible accounts expense; (12) liability for uninsured claims and for claims in excess of insurance coverage, including those for personal injury and property damage arising from explosions, terrorism, natural disasters and other catastrophic events that may result from operating hazards and risks incidental to generating and distributing electricity and transporting, storing and distributing natural gas; (13) transmission or distribution system service interruptions; (14) political, regulatory and economic conditions in the United States; (15) capital market conditions, including reduced access to capital markets and interest rate fluctuations; (16) changes in commodity market prices resulting in significantly higher cash collateral requirements; (17) the interruption, disruption, failure or malfunction of our information technology systems, including due to cyber attack; and (18) continued analysis of recent tax legislation.

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 a natural gas distribution utility division that operates in Pennsylvania and portions of one Maryland county (“Gas Utility”) and an electric utility division that operates in Pennsylvania (“Electric Utility”). The Company is a wholly owned subsidiary of UGI Corporation (“UGI”).

Gas Utility consists of the regulated natural gas distribution businesses of UGI Utilities, which prior to October 1, 2018, was comprised of UGI Utilities and two separate, wholly owned natural gas distribution utility subsidiaries, UGI Penn Natural Gas, Inc. (“PNG”), and UGI Central Penn Gas, Inc. (“CPG”). UGI Utilities, PNG and CPG have been consolidated by merger effective October 1, 2018 (the “Utilities Merger”), with UGI Utilities as the surviving entity. Gas Utility serves more than 642,000 customers in eastern and central Pennsylvania and more than 500 customers in portions of one Maryland county. UGI Utilities’ natural gas distribution utility is referred to as “UGI Gas.” 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 (“PAPUC”) and, with respect to its several hundred customers in Maryland, the Maryland Public Service Commission (“MDPSC”). Electric Utility is regulated by the PAPUC.

UGI Utilities was incorporated in Pennsylvania in 1925. Our executive offices are located at 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 2019,” “Fiscal 2018,” “Fiscal 2017” and “Fiscal 2016” refer to the fiscal years ended September 30, 2019, September 30, 2018, September 30, 2017 and September 30, 2016, respectively.

GAS UTILITY

Service Area; Revenue Analysis

Gas Utility provides natural gas distribution services to more than 642,000 customers in certificated portions of 44 eastern and central Pennsylvania counties through its distribution system. Contemporary materials, such as plastic or coated steel, comprise approximately 90% of Gas Utility's 12,300 miles of gas mains, with bare steel pipe comprising approximately 8% and cast iron pipe comprising approximately 2% of Gas Utility's gas mains. In accordance with Gas Utility’s agreement with the PAPUC, Gas Utility will replace the cast iron portion of its gas mains by March 2027 and the bare steel portion of its gas mains 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, paper product manufacturing, and several power generation facilities. 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 2018 was approximately 264 billion cubic feet (“bcf”). System sales of gas accounted for approximately 23% of system throughput, while gas transported for residential, commercial and industrial customers who bought their gas from others accounted for approximately 77% 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 Marcellus, Gulf Coast, Mid-Continent, and Appalachian sources. For its transportation and storage functions, 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 2018, Gas Utility purchased approximately 92.8 bcf of natural gas for sale to retail 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. Nearly 94% of the volumes purchased were supplied under agreements with 10 suppliers. The remaining 6% of gas purchased by Gas Utility was supplied by 10 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. For Fiscal 2018, approximately 59% of Gas Utility's sales volume was supplied, and approximately 96% 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 recent years. 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 PAPUC or by law, to provide gas distribution services. All of Gas Utility's customers, including core-market customers, have the right to purchase gas supplies from entities other than natural gas distribution utility companies.

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 42% of Gas Utility's annual throughput volume for commercial and industrial customers includes non-interruptible customers with firm rates with locations that afford them the opportunity of seeking transportation service directly from interstate pipelines, thereby bypassing Gas Utility. In addition, nearly 17% 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 38 such customers, 35 of which have transportation contracts extending beyond Fiscal 2019. 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 2019. 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 2018, Gas Utility supplied transportation service to 10 electric generation facilities and installed new service to three co-generation facilities. Gas Utility continues to seek new residential, commercial, and industrial customers for both firm and interruptible service. In Fiscal 2018, Gas Utility connected approximately 1,900 new commercial and industrial customers. In the residential market sector, Gas Utility added over 12,000 residential heating customers during Fiscal 2018. Approximately 54% of these customers converted to natural gas heating from other energy sources, mainly oil and electricity. New home construction 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 2018.

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 providers of gas supply resources, and in proceedings before regulatory agencies, is to ensure 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 2018, approximately 56% of sales volume came from residential customers, 32% from commercial customers, and 12% 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 PAPUC. 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 2018, twelve 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 2018, 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 PAPUC 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 PAPUC. 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

UGI Gas Merger

On March 8, 2018, UGI Utilities and its wholly owned subsidiaries, PNG and CPG, filed an application with the PAPUC for permission (i) to merge PNG and CPG with and into UGI Utilities and (ii) for UGI Utilities to adopt the preexisting PNG and CPG tariffs, rates and terms and conditions of service for inclusion in the UGI Gas tariff, and (iii) thereafter operate as the UGI South (encompassing the former service territory of UGI Gas), UGI North rate district (formerly PNG) and UGI Central rate district (formerly CPG) rate districts of UGI Utilities, respectively. The authority to merge was granted in a September 20, 2018 PAPUC Opinion and Order, and the merger became effective October 1, 2018. The merger was also separately approved by the MDPSC.

Pennsylvania Public Utility Commission Jurisdiction

UGI Utilities' utility operations are subject to regulation by the PAPUC as to rates, terms and conditions of service, accounting matters, issuance of securities, contracts and other arrangements with affiliated entities, gas and electric safety 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 costs other than PGCs and electric default service costs are primarily established in general base rate proceedings.

Gas Utility Rates

In January 2016, UGI Utilities filed a request with the PAPUC for its first gas base rate increase in over 21 years. On October 14, 2016, the PAPUC approved a settlement that was effective October 19, 2016 and resulted in a $27.0 million increase in annual base rate revenues. The settlement permitted the Company to establish new reconcilable surcharges to permit the timely recovery of the costs of universal service programs designed to assist low income customers, and costs associated with a new energy efficiency and conservation program. The Company was also permitted to implement a new Technology and Economic Development Rider to provide additional flexibility in establishing the rates of smaller volume commercial and industrial customers to encourage cost-effective load growth.

On January 19, 2017, PNG (now known as the UGI North rate district) filed a rate request with the PAPUC to increase its base operating revenues for residential, commercial, and industrial customers by $21.7 million annually. On August 31, 2017, the PAPUC approved a settlement that permitted PNG to increase its annual base distribution rates by $11.3 million, effective October 20, 2017. The settlement also permitted PNG to recover costs associated with a new energy efficiency and conservation program and, similar to UGI Gas, also permitted PNG to implement a new Technology and Economic Development Rider to provide additional flexibility in establishing the rates of smaller volume commercial and industrial customers to encourage cost-effective load growth.

On February 20, 2014, the PAPUC 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. Each of the Company's gas businesses 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 PAPUC 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 PAPUC-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 PAPUC. 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 PAPUC.

Prior to the merger effective October 1, 2018, the PAPUC approved LTIIPs for UGI Gas, PNG, and CPG in 2014, and on June 30, 2016, approved a revised LTIIP for these entities that increased the projected spend on DSIC-eligible property for the 2016-2018 period from approximately $266.3 million to $402.8 million. On August 2, 2018, the PAPUC approved one-year extensions through December 31, 2019 to the existing UGI Gas, PNG and CPG LTIIPs. The modified LTIIPs provide for approximately $185.0 million of projected spend on DSIC-eligible property during calendar year 2019. The PAPUC also approved DSIC mechanisms for PNG and CPG in September 2014 and July 2015, respectively. On March 31, 2016, PNG and CPG filed petitions with the PAPUC seeking to increase the cap on their DSIC rate mechanisms from five percent to ten percent of billed distribution revenues. On May 10, 2017, the PAPUC issued a final Order to approve an increase of the maximum allowable DSIC to 7.5% of billed distribution revenues effective July 1, 2017, for PNG and CPG, pending reconsideration of each company's LTIIP filing.

On November 9, 2016, UGI Gas received PAPUC approval to establish a DSIC tariff mechanism effective January 1, 2017, subject to refund and recoupment based on the PAPUC's final resolution of certain matters set aside for hearing before an Administrative Law Judge. Those matters were subsequently resolved in a PAPUC Order entered on July 13, 2017, and UGI Gas commenced collections under its natural gas DSIC on July 1, 2018.

Currently, UGI South and UGI Central are collecting DSIC revenues, while UGI North will resume DSIC revenue collection once the UGI North rate district places into service a threshold level of DSIC eligible plant agreed upon in the settlement of its more recent base rate case.

The tariffs of UGI Gas' rate districts include PGC rates applicable to firm retail rate schedules for customers who do not obtain natural gas supply service from an alternative supplier. These PGC rates permit recovery of substantially all of the prudently incurred costs of natural gas that UGI Gas sells to its customers. PGC rates are reviewed and approved annually by the PAPUC. UGI Gas' rate districts 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 PAPUC and are subject to review during the next annual PGC filing. Each proposed annual PGC rate is required to be filed with the PAPUC six months prior to its effective date. During this period, the PAPUC 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 PAPUC issues an order permitting the collection of gas costs at levels that meet such standard. The PGC mechanism also provides for an annual reconciliation and for the payment or collection of interest on over and under collections. UGI Gas' rate districts may release or sell to and recover from alternative natural gas suppliers the costs of gas supply contracts and transportation capacity acquired to serve the needs of smaller volume customers who elect to receive their natural gas supply service from an alternative supplier.

On April 28, 2017, UGI Gas, PNG, and CPG filed the Gas Delivery Enhancement Rider ("GDE") with the PAPUC. The GDE provides a tariff mechanism to recover from certain non-choice transportation customers a portion of the costs associated with temporary mobile sources of gas supply and interstate pipeline demand charge enhancements (collectively, "GDE Charges") that are incurred to achieve least-cost timely solutions to system reinforcement needs or for pipeline integrity management activities. GDE Charges exclude costs that are recovered through existing PGC rate mechanisms as established in each company's annual 66 Pa.C.S. § 1307(f) PGC proceeding. On August 31, 2017, the PAPUC entered an order approving the GDE Rider for all three companies.

On June 23, 2016, Act 47 of 2016 was enacted. Act 47 revised the interest rates that applied to PGC over and under collections, removed the requirement that over and under collections be assessed to customers who leave default service to obtain natural gas from an alternative supplier by way of a so-called migration rider, provided additional assurance of cost recovery for PGC costs, and granted natural gas distribution companies the right to recover the reasonable costs incurred to implement customer choice on a full and current basis through a reconcilable rate mechanism. Gas Utility implemented the interest rate revision and migration rider provisions of Act 47 in December 2016.

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

On January 26, 2018, Electric Utility filed a request with the PAPUC for its first base rate increase in over 22 years. On October 25, 2018, the PAPUC entered an Opinion and Order authorizing a $3.2 million increase in annual base distribution rates effective October 27, 2018. The PAPUC also authorized Electric Utility to establish a new reconcilable surcharge to permit the timely recovery of the costs of universal service programs designed to assist low income customers and required the Company to refund approximately $0.21 million of tax benefits and associated interest relating to the Tax Cuts and Jobs Act (the "TCJA") through a one time bill credit.

Electric Utility's tariff includes rates, applicable to so-called "default service" customers who do not obtain electric generation service from an alternative supplier, incurred pursuant to a PAPUC-approved supply plan. These default service rates are reconcilable, may be adjusted quarterly, and are designed to permit Electric Utility to recover the full costs of providing default service in a full and timely manner. Electric Utility has received PAPUC approval of its current default service rules and supply plan through May 31, 2021. Electric Utility's default service rates include recovery of costs associated with compliance with 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.

On August 16, 2017, Electric Utility filed a Petition for Approval of its initial LTIIP with the PAPUC for the 2018-2022 time period, which was approved by a PAPUC Opinion and Order entered on December 21, 2017. Electric Utility's projected annual investment in distribution infrastructure replacement was approximately $7.6 million in Fiscal 2018, and will increase to $8.3 million by the fiscal year ending September 30, 2022. With the completion of its base rate case, Electric Utility is now eligible to file for permission to implement a DSIC.

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 PAPUC 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.

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.

Other Government Regulation

In addition to regulation by the PAPUC 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. See Note 12 to Consolidated Financial Statements.

Employees

At September 30, 2018, UGI Utilities had approximately 1,670 employees.

BUSINESS SEGMENT INFORMATION

The table stating the amounts of revenues, operating income and identifiable assets attributable to UGI Utilities' operating segments for Fiscal 2018, Fiscal 2017 and Fiscal 2016 appears in Note 16 to Consolidated Financial Statements included in this Report and is incorporated herein by reference.

ITEM 1A. RISK FACTORS

RISKS RELATED TO OUR BUSINESS

Regulators may not approve the rates we request and existing rates may be challenged, which may adversely affect our results of operations.

Our Gas Utility and Electric Utility are subject to regulation by the PAPUC. The PAPUC, 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 will periodically file requests with the PAPUC to increase base rates charged to 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 PAPUC, 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 of these and other incidents, we are sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business, including regulatory investigations, claims, lawsuits and other proceedings. Additionally, environmental contamination could result in future legal proceedings. There can be no assurance that our insurance coverage will be adequate to protect us from all material expenses related to pending and future claims or that such levels of insurance would be available in the future at economical prices. Moreover, defense and settlement costs may be substantial, even with respect to claims and investigations that have no merit. If we cannot resolve these matters favorably, our business, financial condition, results of operations and future prospects may be materially adversely affected.

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. We obtain our supply from local Marcellus Shale sources, as well as other trading points in the United States. If we experience physical capacity constraints on one or more of the interstate or intrastate natural gas pipelines that supply our business, we may not be able to supply our customers, which could have an adverse effect on 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, including as a result of overpressurization of or damage to natural gas pipelines. Operation of our transmission and distribution systems below our expectations may result in lost revenues or increased expenses, including higher maintenance costs, civil litigation and the risk of regulatory penalties.

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 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.

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, or we encounter other unforeseen difficulties in the operation of our information technology systems, our operations could be disrupted, our business and reputation may suffer, and our internal controls could be adversely affected.

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, or 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.

Moreover, the efficient execution of our business is dependent upon the proper functioning of its internal systems, such as the information technology systems that support our underlying business processes. Any significant failure or malfunction of such information technology systems may result in disruptions of our operations. In addition, the effectiveness of our internal controls could be adversely affected if we encounter unforeseen problems with respect to the operation of our information technology systems. While we have purchased cyber security insurance, there are no assurances that the coverage would be adequate in relation to any incurred losses.

Unforeseen difficulties with the implementation or operation of our information systems could adversely affect our internal controls and our business.

We contracted with third party consultants to assist us with the design and implementation of an enterprise resource planning system. The efficient execution of our business is dependent upon the proper functioning of our internal information systems. Any significant failure or malfunction of our information systems may result in disruptions to our operations. Our results of operations could be adversely affected if we encounter unforeseen problems with respect to the implementation and operation of this system.

INDUSTRY-SPECIFIC RISKS

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 and attrition. 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.

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 and vendors, 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, less favorable market conditions could restrict our ability to grow through acquisitions, 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 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.

The risk of natural disasters and catastrophic events, including terrorism, may adversely affect the economy and the price of natural gas.

Natural disasters and catastrophic events, such as fires, earthquakes, explosions, floods, tornadoes, hurricanes, terrorist attacks, political unrest and other similar occurrences, may adversely impact the availability of natural gas, which could adversely impact our financial condition and results of operations, our ability to raise capital and our future growth. The impact that the foregoing may have on our industries in general, and on us in particular, is not known at this time. A natural disaster or 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 natural disasters or terrorism could also affect our ability to raise capital.

In response to natural gas incidents 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 PAPUC 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.

Increased regulation of Greenhouse Gas (“GHG”) emissions, such as propane and methane, could impose significant additional costs on us, our suppliers and our customers. Some states have adopted laws and regulations regulating the emission of GHGs for some industry sectors. 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, which include certain facilities of our natural gas distribution business. These subject facilities have been required to monitor emissions since January 2011 and to submit detailed annual reports beginning in March 2012. In October 2015, the EPA promulgated the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the “Clean Power Plan”), which provides standards and guidelines for reducing existing power plants’ GHG emissions and related pollutants by 2030. However, in October 2017, the EPA announced its proposal to repeal the Clean Power Plan in its entirety on the grounds that it exceeds the EPA’s delegated authority under the Clean Air Act. At this time, we cannot predict the effect that climate change regulation may have on our business, financial condition or operations in the future.

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 $50.0 million in Fiscal 2018, $57.7 million in Fiscal 2017, and $47.0 million in Fiscal 2016.

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 Fiscal 2018 operating results benefited from temperatures that were near normal and followed two consecutive years of significantly warmer than normal weather. One of the highlights of our Fiscal 2018 performance was a significant increase in year-over-year total margin, after adjusting margin for the regulatory impacts of the Tax Cuts and Jobs Act ("TCJA"). The significant increase in margin was due to a number of factors including, among others, the return of near normal weather, the impact of the PNG (now UGI North rate district) rate case and customer growth. The significant increase in margin was partially offset by higher operating and administrative costs and lower other operating income as other operating income in the prior year included income from an environmental insurance settlement.

Our consolidated income taxes for Fiscal 2018 were impacted by the TCJA which was enacted on December 22, 2017. The significant changes resulting from the tax law that impact UGI Utilities include a reduction in the U.S. federal income tax rate from 35% to 21%, effective January 1, 2018 (resulting in a blended rate of 24.5% for Fiscal 2018) and the one-time immediate expensing of regulated utility property which for regulated utility companies will be eliminated beginning in Fiscal 2019. As a result of the TCJA, we adjusted our net federal deferred income tax liabilities to remeasure such tax liabilities at the lower corporate rate. Due to the effects of utility ratemaking, most of the remeasurement of UGI Utilities' deferred income tax assets and liabilities was not recognized immediately in income tax expense but has been reflected in regulatory assets and liabilities in accordance with utility ratemaking.

On May 17, 2018, in response to the TCJA, the PAPUC ordered each regulated utility currently not in a general base rate case proceeding to reduce their rates through the establishment of a negative surcharge applied to bills rendered on or after July 1, 2018. The PAPUC Order also required Pennsylvania utilities to establish a regulatory liability for tax benefits that accrued during the period beginning January 1, 2018 through June 30, 2018, resulting from the reduced federal tax rate. As a result of the PAPUC Order, during Fiscal 2018, Gas Utility reduced its revenues by $24.1 million to reflect (1) $17.1 million of tax benefits accrued during the period January 1, 2018, to June 30, 2018, plus (2) $7.0 million to reflect tax benefits expected to be generated by the future amortization of the regulatory liability. The impact of the PAPUC Order on revenues for the period July 1, 2018 to September 30, 2018 was not material.

We continued to add new Gas Utility customers through conversion activity and new home construction. This growth in the number of Gas Utility customers reflects continued high demand for natural gas across the residential and commercial customer segments. Our Gas Utility continued to execute on its infrastructure replacement and system betterment program with record capital expenditures in Fiscal 2018. Our total capital expenditures were nearly $340 million which included record spending on replacement and betterment capital expenditures. In addition to these distribution system expenditures, we spent more than $30 million on buildings and grounds improvements, including the renovation of existing buildings and a new LEED certified headquarters building which is scheduled to be completed in Fiscal 2019. We also made significant progress on our IT project to replace our core general ledger system. We will continue to invest in this and other technology changes during Fiscal 2019 and beyond, with a number of operations-related IT initiatives scheduled over the next several years.

In October 2017, UGI Utilities issued $125 million of variable-rate term loan debt to provide additional long-term financing of its infrastructure replacement and betterment capital program as well as IT initiatives. Later in Fiscal 2018, we increased the borrowing capacity under our revolving credit agreement to $450 million from $300 million previously (see Note 7 to Consolidated Financial Statements). We believe we have sufficient liquidity from our revolving credit facility, cash flow from operations and the ability to issue long-term debt at attractive rates to fund business operations during Fiscal 2019 (see "Financial Condition and Liquidity" below).

ANALYSIS OF RESULTS OF OPERATIONS

The following analyses compare the Company's results of operations for Fiscal 2018, Fiscal 2017 and Fiscal 2016.

Fiscal 2018 Compared with Fiscal 2017

(Dollars in millions)	2018	2017	Increase (Decrease)	
Gas Utility:				
Revenues (a)	$ 994.8	$ 799.1	$ 195.7	24.5 %
Total margin (a)(b)	$ 527.3	$ 480.8	$ 46.5	9.7 %
Operating and administrative expenses	$ 219.7	$ 202.0	$ 17.7	8.8 %
Operating income (a)	$ 230.4	$ 219.6	$ 10.8	4.9 %
Income before income taxes (a)	$ 189.0	$ 181.3	$ 7.7	4.2 %
Net income (a)	$ 146.7	$ 110.1	$ 36.6	33.2 %
System throughput — billions of cubic feet (“bcf”)				
Core market	80.2	70.4	9.8	13.9 %
Total	264.0	243.1	20.9	8.6 %
Degree days — % (warmer) than normal (c)	(2.1)%	(11.1)%	—	—
Electric Utility:				
Revenues	$ 97.6	$ 88.5	$ 9.1	10.3 %
Total margin (b)	$ 37.2	$ 34.8	$ 2.4	6.9 %
Operating and administrative expenses	$ 24.9	$ 21.2	$ 3.7	17.5 %
Operating income	$ 7.1	$ 8.7	$ (1.6)	(18.4)%
Income before income taxes	$ 5.6	$ 6.8	$ (1.2)	(17.6)%
Distribution sales — millions of kilowatt hours (“gwh”)	1,005.9	950.6	55.3	5.8 %

(a) Gas Utility revenues, total margin, operating income and income before income taxes were reduced by $24.1 million to record the effects of income tax savings that accrued during the period January 1, 2018 to June 30, 2018, in accordance with a PAPUC Order issued May 17, 2018, related to the TCJA (see Notes 4 and 8 to Consolidated Financial Statements). Although Gas Utility’s income before income taxes for Fiscal 2018 was negatively impacted by this reduction in revenues, the after-tax impact of this reduction was offset by a reduction in Fiscal 2018 income tax expense principally as a result of the lower federal income tax rate. The impact of the PAPUC Order on revenues for the period July 1, 2018 to September 30, 2018 was not material.

(b) Gas Utility’s total margin represents total revenues less total cost of sales. Electric Utility’s total margin represents total revenues less total cost of sales and Electric Utility gross receipts taxes, of $5.0 million and $4.7 million during Fiscal 2018 and Fiscal 2017, respectively. For financial statement purposes, Electric Utility gross receipts taxes are included in “Operating and administrative expenses” on the Consolidated Statements of Income (but are excluded from Electric Utility operating expenses presented above).

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

Temperatures in Gas Utility’s service territory during Fiscal 2018 were 2.1% warmer than normal but 10.1% colder than Fiscal 2017. Gas Utility core market volumes increased 9.8 bcf (13.9%) reflecting, among other things, the effects of the colder weather and growth in the number of core market customers. Total Gas Utility distribution system throughput increased 20.9 bcf principally reflecting higher large firm delivery service volumes and the higher core market volumes. Gas Utility’s core market customers comprise firm- residential, commercial and industrial (“retail core-market”) customers who purchase their gas from Gas Utility and, to a much lesser extent, residential and small commercial customers who purchase their gas from others. These increases were partially offset by lower interruptible delivery service volumes. Electric Utility kilowatt-hour sales were 5.8% higher than Fiscal 2017, principally reflecting the effects of colder heating-season weather on heating-related sales, and the effects of warmer summer weather on air-conditioning sales.

UGI Utilities revenues increased $204.8 million reflecting a $195.7 million increase in Gas Utility revenues and a $9.1 million increase in Electric Utility revenues. In accordance with a PAPUC Order issued May 17, 2018, during Fiscal 2018 Gas Utility’s revenues were reduced by $24.1 million, and an associated regulatory liability was established, to record the effects of tax savings that accrued during the period January 1, 2018 to June 30, 2018 as a result of the TCJA. Excluding the impact on revenues from the PAPUC Order, Gas Utility revenues increased $218.8 million principally reflecting an increase in core market revenues ($143.0 million), higher off-system sales revenues ($54.6 million), and higher large firm delivery service revenues ($21.2 million).

The $143.0 million increase in Gas Utility core market revenues principally reflects the effects of the higher core market throughput ($70.7 million), higher average retail core market purchased gas cost ("PGC") rates ($61.4 million) and the increase in PNG base rates effective October 20, 2017 ($10.9 million). The increase in Electric Utility revenues principally reflects higher Electric Utility distribution system sales ($6.1 million) and higher average default service ("DS") rates ($2.6 million). Because Gas Utility and Electric Utility are subject to reconcilable PGC and DS recovery mechanisms, increases or decreases in the actual cost of gas or electricity associated with customers who purchase their gas or electricity from UGI Utilities impact revenues and cost of sales but have no direct effect on retail core-market margin (see Note 4 to Consolidated Financial Statements for a discussion of these recovery mechanisms). UGI Utilities cost of sales was $522.9 million in Fiscal 2018 compared with $367.3 million in Fiscal 2017, principally reflecting higher Gas Utility cost of sales ($149.3 million) and higher Electric Utility cost of sales ($6.3 million). The higher Gas Utility cost of sales principally reflects higher average retail core market PGC rates ($61.4 million), higher cost of sales associated with Gas Utility off-system sales ($54.6 million), and higher retail core-market volumes ($26.8 million). The higher Electric Utility cost of sales reflects the higher electricity sales.

UGI Utilities total margin increased $48.9 million principally reflecting higher total margin from Gas Utility core market customers ($53.9 million) and higher large firm delivery service total margin ($15.8 million) offset by the reduction in margin resulting from the PAPUC's May 17, 2018 Order regarding the effects of the TCJA. The increase in Gas Utility core market margin principally reflects the higher core market throughput ($44.6 million) and the increase in PNG base rates effective October 20, 2017 ($9.3 million). Electric Utility total margin increased $2.4 million principally reflecting the higher distribution system sales.

UGI Utilities operating income increased $9.2 million principally reflecting the increase in total margin ($48.9 million) partially offset by higher operating and administrative expenses ($21.4 million), greater depreciation expense ($12.3 million) associated with increased distribution system and IT capital expenditure activity, and lower other operating income ($6.1 million). The increase in UGI Utilities operating and administrative expenses principally reflects higher uncollectible accounts expense ($9.9 million), higher contractor and outside services expenses ($5.0 million), higher IT maintenance and consulting expenses ($4.0 million) and higher compensation and benefits expenses ($2.6 million). The decrease in other operating income principally reflects the absence of $5.8 million of income from an environmental insurance settlement recorded in Fiscal 2017. UGI Utilities income before income taxes increased $6.5 million reflecting the increase in UGI Utilities operating income ($9.2 million) partially offset by higher interest expense.

Interest Expense and Income Taxes

Interest expense in Fiscal 2018 increased $2.7 million primarily reflecting incremental interest on higher average long-term debt outstanding, higher average short-term debt outstanding and higher short-term interest rates. Our income taxes as a percentage of pretax income for Fiscal 2018 was 23.5% compared to an effective tax rate of 38.3% in Fiscal 2017. Our consolidated income taxes for Fiscal 2018 were impacted by the enactment of the TCJA. As previously mentioned, we are subject to a blended federal tax rate of 24.5% for Fiscal 2018. As a result of the TCJA, we adjusted our net federal deferred income tax liabilities to remeasure such tax liabilities at the lower federal corporate rate. Certain of these adjustments reduced income tax expense, and increased net income, by $8.0 million. In addition to these adjustments that impacted our Fiscal 2018 net income, our income taxes were further reduced by $23.4 million principally reflecting the impact of the lower Fiscal 2018 income tax rate and, to a much lesser extent, the amortization of excess deferred federal income taxes.

Fiscal 2017 Compared with Fiscal 2016

(Dollars in millions)	2017	2016	Increase (Decrease)	
Gas Utility:				
Revenues	$ 799.1	$ 677.4	$ 121.7	18.0 %
Total margin (a)	$ 480.8	$ 438.2	$ 42.6	9.7 %
Operating and administrative expenses	$ 202.0	$ 184.0	$ 18.0	9.8 %
Operating income	$ 219.6	$ 189.4	$ 30.2	15.9 %
Income before income taxes	$ 181.3	$ 153.6	$ 27.7	18.0 %
System throughput — bcf				
Core market	70.4	66.2	4.2	6.3 %
Total	243.1	212.4	30.7	14.5 %
Degree days — % (warmer) colder than normal (b)	(11.1)%	(13.6)%	—	—
Electric Utility:				
Revenues	$ 88.5	$ 91.1	$ (2.6)	(2.9)%
Total margin (a)	$ 34.8	$ 35.6	$ (0.8)	(2.2)%
Operating and administrative expenses	$ 21.2	$ 19.3	$ 1.9	9.8 %
Operating income	$ 8.7	$ 11.5	$ (2.8)	(24.3)%
Income before income taxes	$ 6.8	$ 9.6	$ (2.8)	(29.2)%
Distribution sales — gwh	950.6	961.6	(11.0)	(1.1)%

(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 Electric Utility gross receipts taxes of $4.7 million and $4.8 million during Fiscal 2017 and Fiscal 2016, respectively. For financial statement purposes, Electric Utility gross receipts taxes are included in "Operating and administrative expenses" on the Consolidated Statements of Income (but are excluded from Electric Utility operating expenses presented above).

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

Temperatures in Gas Utility's service territory during Fiscal 2017 were 11.1% warmer than normal but 2.6% colder than during Fiscal 2016. Gas Utility core market volumes increased 4.2 bcf (6.3%) principally reflecting the effects of the slightly colder Fiscal 2017 weather and growth in the number of core market customers. Total Gas Utility distribution system throughput increased 30.7 bcf reflecting significantly higher large firm delivery service volumes principally associated with service to a new natural gas-fired generation facility and the higher core market volumes. These increases were partially offset by lower interruptible delivery service volumes. Electric Utility kilowatt-hour sales were 1.1% lower than in the prior year, principally reflecting the impact on air-conditioning sales from cooler summer temperatures.

UGI Utilities Fiscal 2017 revenues increased $119.1 million reflecting a $121.7 million increase in Gas Utility revenues partially offset by slightly lower Electric Utility revenues. The higher Gas Utility revenues principally reflect an increase in core market revenues ($85.1 million), higher large firm delivery service revenues ($14.3 million) and higher off-system sales revenues ($25.0 million). The $85.1 million increase in Gas Utility core market revenues reflects higher average retail core market PGC rates ($37.0 million), the effects of the higher core market throughput ($28.0 million) and the increase in UGI Gas base rates effective October 19, 2016 ($20.1 million). The decrease in Electric Utility revenues principally reflects the lower Electric Utility volumes ($1.8 million), slightly lower average DS rates ($0.5 million) and lower transmission revenue ($0.4 million). UGI Utilities cost of sales was $367.3 million in Fiscal 2017 compared with $289.8 million in Fiscal 2016, principally reflecting higher average retail core market PGC rates ($37.0 million), the higher Gas Utility retail core-market volumes ($14.0 million) and higher cost of sales associated with Gas Utility off-system sales ($25.0 million). The higher Gas Utility cost of sales is partially offset by a decrease in Electric Utility cost of sales of $1.5 million reflecting the lower volumes sold and the slightly lower DS rates.

UGI Utilities total margin increased $41.7 million principally reflecting higher total margin from Gas Utility core market customers ($32.7 million) and higher large firm delivery service total margin ($11.4 million) partially offset by lower other margin. The increase in Gas Utility core market margin principally reflects the increase in UGI Gas base rates effective October 19, 2016 ($20.1

million) and the higher core market throughput ($12.6 million). Electric Utility total margin decreased $0.8 million principally reflecting the lower volume sales and lower transmission revenue.

UGI Utilities Fiscal 2017 operating income increased $27.4 million, principally reflecting the increase in total margin ($41.7 million) and higher other operating income, net ($10.3 million). These increases in operating income were reduced by higher operating and administrative expenses ($19.9 million) and higher depreciation expense ($5.0 million) associated with increased capital expenditure activity. The higher other operating income, net, reflects a $5.8 million environmental insurance settlement, the absence of a charge recorded in the prior year related to environmental matters ($2.5 million), and lower interest on PGC overcollections ($1.6 million). The increase in UGI Utilities operating and administrative expenses reflects higher pension and employee benefits expenses ($7.0 million), higher customer accounts expense ($4.2 million) and higher regulatory asset amortization expense related to environmental remediation expenses ($1.9 million). The increase in Fiscal 2017 operating and administrative expenses also reflects the fact that Fiscal 2016 expenses were reduced by the capitalization of $5.4 million of development stage IT project costs that had been expensed in prior periods but qualified for capitalization during Fiscal 2016. UGI Utilities income before income taxes increased $24.8 million reflecting the increase in UGI Utilities operating income ($27.4 million) partially offset by higher interest expense.

Interest Expense and Income Taxes. Interest expense in Fiscal 2017 increased principally reflecting higher average long-term debt outstanding. Our income taxes as a percentage of pre-tax income for Fiscal 2017 was 38.3% compared to an effective income tax rate of 40.4% in Fiscal 2016. The lower Fiscal 2017 effective income tax rate is due primarily to the impact of excess tax benefits on share-based payments resulting from the adoption of new accounting guidance effective October 1, 2016 and the beneficial effects of higher flow through of accelerated state tax depreciation.

FINANCIAL CONDITION AND LIQUIDITY

Capitalization and Liquidity

UGI Utilities total debt outstanding was $1,027.5 million at September 30, 2018, which includes $189.5 million of short-term borrowings, compared with total debt outstanding of $921.1 million at September 30, 2017, which includes $170 million of short-term borrowings. UGI Utilities' total long-term debt outstanding at September 30, 2018, comprises $675.0 million of Senior Notes, a $120.3 million variable-rate term loan, $40.0 million of Medium-Term Notes and $6.8 million of other long-term debt, and is net of $4.1 million of unamortized debt issuance costs.

In October 2017, UGI Utilities entered into a $125 million unsecured variable-rate term loan agreement (the "Term Loan") with a group of banks. Proceeds from the Term Loan were used to repay revolving credit agreement borrowings and for general corporate purposes. The Term Loan is payable in equal quarterly installments of $1.6 million, commencing in March 2018, with the balance of the principal being due and payable in full on October 30, 2022 Under the Term Loan, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.875% and is based upon the credit ratings of certain indebtedness of UGI Utilities. In July 2018, UGI Utilities entered into a forward-starting pay-fixed, receive-variable interest rate swap that generally fixes the underlying prevailing market interest rates on Term Loan borrowings at approximately 3.00% through July 2022. This forward-starting interest rate swap commences September 30, 2019. We have designated this forward-starting interest rate swap as a cash flow hedge.

In September 2018, UGI Utilities entered into an Increasing Lender Commitment and Acceptance (the "Commitment and Acceptance") under its existing unsecured, revolving credit agreement (the "Credit Agreement"). The Commitment and Acceptance increases the amount of loan commitments under the Credit Agreement to $450 million from $300 million (including a $100 million sublimit for letters of credit) which expires in March 2020. Borrowings under the Credit Agreement are classified as short-term borrowings on the Consolidated Balance Sheets. During Fiscal 2018 and Fiscal 2017, average daily short-term borrowings under the Credit Agreement were $150.4 million and $80.7 million, respectively, and peak short-term borrowings totaled $215.0 million and $178.0 million, respectively. Peak short-term borrowings typically occur during the heating season months of December and January when UGI Utilities' investment in working capital, principally accounts receivable, is generally greatest.

Based upon cash expected to be generated from operations and borrowings under the Credit Agreement, management believes the Company will be able to meet its anticipated contractual and projected cash commitments during Fiscal 2019. 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 the Credit Agreement to manage seasonal cash flow needs.

Cash provided by operating activities was $288.6 million in Fiscal 2018, $243.6 million in Fiscal 2017 and $205.4 million in Fiscal 2016. Cash provided by operating activities before changes in operating working capital was $330.7 million in Fiscal 2018, $288.7 million in Fiscal 2017 and $204.9 million in Fiscal 2016. The increase in cash flow from operating activities in Fiscal 2018 compared with Fiscal 2017 principally reflects the impact of the improved operating results. The increase in cash flow from operating activities in Fiscal 2017 compared with Fiscal 2016 principally reflects the impact of improved operating results and the absence of a $36.0 million cash settlement of interest rate protection agreements ("IRPAs") paid in Fiscal 2016. Changes in operating working capital (used) provided $(42.1) million of cash in Fiscal 2018, $(45.1) million of cash in Fiscal 2017 and $0.5 million of cash in Fiscal 2016. Cash used to fund changes in operating working capital in Fiscal 2018 includes an increase in accounts receivable reflecting in large part the impact of higher natural gas prices, and estimated federal income tax overpayments resulting from TCJA regulations released late in Fiscal 2018 regarding bonus depreciation for utility assets. These uses of cash were partially offset by higher cash from net deferred fuel cost overcollections. Cash used to fund changes in operating working capital in Fiscal 2017 includes the impact of higher natural gas prices on changes in accounts receivable and inventories, and net deferred fuel cost refunds.

Investing activities. Cash used by investing activities was $331.7 million in Fiscal 2018, $320.5 million in Fiscal 2017, and $252.5 million in Fiscal 2016. The increase in capital expenditures in Fiscal 2018 compared to Fiscal 2017 principally reflects higher expenditures associated with buildings and grounds improvements and higher replacement and betterment capital expenditures, partially offset by lower IT capital expenditures. The increase in capital expenditures in Fiscal 2017 compared to Fiscal 2016 principally reflects higher capital expenditures associated with a pipeline expansion project and higher IT capital expenditures. Fiscal 2018 cash flow from investing activities includes a $1.9 million decrease in restricted cash in futures brokerage accounts compared to a $2.5 million increase in Fiscal 2017 and a $6.0 million decrease in Fiscal 2016. Changes in restricted cash in futures brokerage accounts are generally the result of changes in underlying commodity prices.

Financing activities. Cash provided by financing activities was $48.2 million in Fiscal 2018, $79.3 million in Fiscal 2017 and $46.9 million in Fiscal 2016. 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. In Fiscal 2018, UGI Utilities entered into a $125 million unsecured term loan agreement and used the net proceeds principally to reduce revolving credit balances and for general corporate purposes. Also in Fiscal 2018, UGI Utilities repaid $40 million of maturing Medium-Term Notes and $4.7 million of Term Loan debt. During Fiscal 2017, UGI Utilities issued $100 million of Senior Notes and used the net proceeds principally to fund infrastructure replacement and betterment capital expenditures, IT initiatives and for general corporate purposes. Fiscal 2016 includes the issuance of $300 million of senior notes, the proceeds of which were used to repay maturing long-term debt and short-term borrowings.

Capital Expenditures

In the following table, we present capital expenditures by business segment for Fiscal 2018, Fiscal 2017 and Fiscal 2016. We also provide amounts we expect to spend in Fiscal 2019. We expect to finance a substantial portion of our Fiscal 2019 capital expenditures from cash generated by operations and borrowings under the Credit Agreement.

(Millions of dollars)	2019	2018	2017	2016
	(estimate)			
Gas Utility	$ 344.0	$ 320.0	$ 306.2	$ 251.3
Electric Utility	31.0	18.5	11.5	11.2
	$ 375.0	$ 338.5	$ 317.7	$ 262.5

Fiscal 2018 Gas Utility capital expenditures include amounts associated with construction of a new headquarters building. Fiscal 2019 estimated capital expenditures at Gas Utility include slightly higher main replacement and system improvement capital expenditures, expenditures associated with buildings and grounds improvements, and IT expenditures associated with the replacement of an Enterprise Risk Management ("ERP") system. The increase in estimated Fiscal 2019 Electric Utility capital expenditures includes infrastructure replacement and upgrade expenditures and facility improvements.

Contractual Cash Obligations and Commitments

UGI Utilities has contractual cash obligations that extend beyond Fiscal 2018, including scheduled repayments of long-term debt and interest, operating lease obligations, unconditional purchase obligations for pipeline transportation and natural gas storage services, and commitments to purchase natural gas and electricity. The following table presents significant contractual cash obligations under agreements existing as of September 30, 2018:

	Payments Due by Period				
(Millions of dollars)	Total	Fiscal 2019	Fiscal 2020 - 2021	Fiscal 2022 - 2023	Thereafter
Long-term debt (a)	$ 842.1	$ 9.0	$ 16.1	$ 102.1	$ 714.9
Interest on long-term fixed rate debt (b)	761.4	36.3	72.0	71.2	581.9
Operating leases	5.3	2.2	1.9	1.1	0.1
UGI Utilities supply, storage and transportation contracts	743.1	183.0	235.0	137.6	187.5
Total	$ 2,351.9	$ 230.5	$ 325.0	$ 312.0	$ 1,484.4

(a) Based upon stated maturity dates.
(b) Based upon stated interest rates.

The components of the “Other noncurrent liabilities” included in our Consolidated Balance Sheet at September 30, 2018, 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 2019 will not be material. Contributions to the pension plan in years beyond Fiscal 2019 will depend in large part on the impacts of future returns on pension plan assets and interest rates on pension plan liabilities. 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 $531.7 million and $498.1 million at September 30, 2018 and 2017, respectively. At September 30, 2018 and 2017, the underfunded positions of the Pension Plan, defined as the excess of the projected benefit obligations (“PBOs”) over the Pension Plan’s assets, were $79.5 million and $141.2 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 Pension Plan in Fiscal 2019 are not expected to be material. Pre-tax pension cost associated with the Pension Plan in Fiscal 2018 was $11.7 million. Pre-tax pension cost associated with Pension Plan in Fiscal 2019 is expected to be approximately $5.5 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, 2018, we have recorded cumulative after-tax charges to stockholder’s equity of $4.9 million and regulatory assets of $87.1 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

Utilities Merger. On March 8, 2018 and March 13, 2018, the Company filed merger authorization requests with the PAPUC and MDPSC, respectively, to merge PNG and CPG into UGI Utilities, with a targeted effective date of October 1, 2018. After receiving all necessary FERC, MDPSC, and PAPUC approvals, CPG and PNG were merged into UGI Utilities effective October 1, 2018. Consistent with the MDPSC order issued July 25, 2018, and the PAPUC order issued September, 26, 2018, the former CPG, PNG and UGI Utilities, Inc. Gas Division service territories, respectively, became the UGI Central, UGI North and UGI South rate districts of the UGI Utilities, Inc. Gas Division, without any ratemaking changes. The Company’s obligations under the settlement approved by the PAPUC include various non-monetary conditions requiring the Company to maintain separate accounting-type schedules for limited future ratemaking purposes.

Base Rate Filings. On January 26, 2018, Electric Utility filed a rate request with the PAPUC to increase its annual base distribution revenues by $9.2 million, which was later reduced by the Company to $7.7 million to reflect the impact of the TCJA and other adjustments. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable electric service. On October 25, 2018, the PAPUC approved a final order providing for a $3.2 million annual base distribution rate increase for Electric Utility. The increase became effective on October 27, 2018. As part of the final order, the Company is required to provide customers with a one-time $0.2 million billing credit associated with 2018 TCJA tax benefits.

On August 31, 2017, the PAPUC approved a previously filed Joint Petition for Approval of Settlement of all issues providing for an $11.3 million base distribution rate increase for PNG (now the UGI North rate district of Gas Utility). The increase became effective October 20, 2017.

On October 14, 2016, the PAPUC approved a previously filed Joint Petition for Approval of Settlement of all issues providing for a $27.0 million annual base distribution rate increase for UGI Gas (now the UGI South rate district of Gas Utility). The increase became effective on October 19, 2016.

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

PNG and CPG received PAPUC approval on a DSIC tariff, initially set at zero, in 2014. PNG and CPG began charging a DSIC at a rate other than zero, beginning on April 1, 2015 and April 1, 2016, respectively. In May 2017, the PAPUC issued a final Order to approve an increase of the maximum allowable DSIC to 7.5% of billed distribution revenues effective July 1, 2017, for PNG and CPG, pending reconsideration at each company’s Long-Term Infrastructure Improvement Plan filing. PNG’s DSIC has been reset to zero as a result of its most recent base rate case. The DSIC rate for PNG will resume under the UGI North rate district upon exceeding the threshold amount of DSIC-eligible plant in service agreed upon in the settlement of its most recent base rate case.

In November 2016, UGI Gas received PAPUC approval to establish a DSIC tariff mechanism, capped at 5% of distribution charges billed to customers, effective January 1, 2017. UGI Gas began recovering revenue under the mechanism effective July 1, 2018, as it exceeded the threshold amount of DSIC-eligible plant agreed upon in the settlement of its recent base rate case during the third quarter of Fiscal 2018.

Manor Township, Pennsylvania Natural Gas Incident Complaint. In connection with a July 2, 2017, explosion in Manor Township, Lancaster County, PA, that resulted in the death of one Company employee and injuries to two Company employees and one sewer authority employee, and destroyed two residences and damaged several other homes, the PAPUC Bureau of Investigation and Enforcement (“BIE”) filed a formal complaint at the PAPUC in which BIE alleges that the Company committed multiple violations of federal and state gas pipeline regulations in connection with its emergency response leading up to the explosion, and requested that the PAPUC order the Company to pay approximately $2.1 million in civil penalties, which is the maximum allowable fine. On November 16, 2018, the Company filed its formal written answer contesting the BIE complaint.

MANUFACTURED GAS PLANTS

From the late 1800s through the mid-1900s, UGI Utilities and its current and former subsidiaries owned and operated a number of manufactured gas plants (“MGPs”) prior to the general availability of natural gas. Some constituents of coal tars and other residues of the manufactured gas process are today considered hazardous substances under the Superfund Law and may be present on the sites of former MGPs. Between 1882 and 1953, UGI Utilities owned the stock of subsidiary gas companies in Pennsylvania and elsewhere and also operated the businesses of some gas companies under agreement. By the early 1950s, UGI Utilities divested all of its utility operations other than certain Pennsylvania operations, including those now constituting UGI Gas and Electric Utility. Beginning in 2006 and 2008, UGI Utilities also owned and operated two acquired subsidiaries (CPG and PNG) with similar histories of owning, and in some cases operating, MGPs in Pennsylvania. PNG and CPG were merged into UGI Utilities effective October 1, 2018.

Prior to the Utilities Merger, each of UGI Utilities and its subsidiaries, CPG and PNG, were subject to a consent order and agreement (“COA”) with the Pennsylvania Department of Environmental Protection (“PADEP”) to address the remediation of specified former MGP sites in Pennsylvania. In accordance with the COAs, as amended to recognize the merger, UGI Utilities, as the successor to CPG and PNG, is required to either obtain a certain number of points per calendar year based on defined eligible environmental investigatory and/or remedial activities at the MGPs and in the case of one COA, an additional obligation to plug specific natural gas wells, or make expenditures for such activities in an amount equal to an annual environmental cost cap. The cost cap of the three COAs, in the aggregate, is $5.4 million. The three COAs are scheduled to terminate at the end of 2031, 2020, and 2020. At September 30, 2018 and 2017, our aggregate estimated accrued liabilities for environmental investigation and remediation costs related to the COAs totaled $51.0 million and $54.3 million, respectively. UGI Utilities has recorded associated regulatory assets for these costs because recovery of these costs from customers is probable. (See Note 4 to the Consolidated Financial Statements).

UGI Utilities does not expect the costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to its results of operations because UGI Utilities receives ratemaking recovery of actual environmental investigation and remediation costs associated with the sites covered by the COAs. This ratemaking recognition reconciles the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites.

From time to time, UGI Utilities is notified of sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by UGI Utilities or owned or operated by a former subsidiary. Such parties generally investigate the extent of environmental contamination or perform environmental remediation. Management believes that under applicable law, UGI Utilities should not be liable in those instances in which a former subsidiary owned or operated an MGP. There could be, however, significant future costs of an uncertain amount associated with environmental damage caused by MGPs outside Pennsylvania that UGI Utilities directly operated, or that were owned or operated by a former subsidiary of UGI Utilities if a court were to conclude that (1) the subsidiary's separate corporate form should be disregarded, or (2) UGI Utilities should be considered to have been an operator because of its conduct with respect to its subsidiary's MGP. At September 30, 2018 and 2017, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Utilities' MGP sites outside Pennsylvania was material.

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 PAPUC in past rate case proceedings and management audits as a reasonable method of allocating such expenses. UGI Utilities also engages in other services with various other affiliates pursuant to arrangements authorized by the PAPUC using similar allocation or market-based pricing methods. 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 PAPUC affiliated interest agreements. Amounts billed to these entities by UGI Utilities during Fiscal 2018, Fiscal 2017 and Fiscal 2016 totaled $5.3 million, $4.3 million and $5.1 million, respectively.

From time to time, UGI Utilities is a party to storage contract administrative agreements ("SCAAs") with UGI Energy Services, LLC ("Energy Services") which have terms of up to three years. At September 30, 2018, UGI Utilities was a party to four SCAAs with Energy Services, 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, released certain storage and transportation contracts (subject to recall for operational purposes) to Energy Services for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon the commencement of the SCAAs, receives a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the term of the SCAAs. UGI Utilities incurred costs associated with Energy Services' SCAAs during Fiscal 2018, Fiscal 2017 and Fiscal 2016 totaling $19.9 million, $21.4 million and $12.7 million, respectively. Energy Services, in turn, provides a firm delivery service and makes certain payments to UGI Utilities for its various obligations under the SCAAs. During Fiscal 2018, Fiscal 2017 and Fiscal 2016, these payments totaled $2.8 million, $2.7 million and $2.0 million, respectively. In conjunction with the SCAAs, UGI Utilities received security deposits from Energy Services. At September 30, 2018 and 2017, the amounts of such security deposits, which are included in "Other current liabilities" on the Consolidated Balance Sheets, were $11.0 million.

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." At September 30, 2018 and 2017, the carrying values of these gas storage inventories, comprising approximately 6.7 bcf and 6.8 bcf of natural gas, were $17.7 million and $19.3 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 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 2018, Fiscal 2017 and Fiscal 2016 totaled $93.6 million, $76.0 million and $63.3 million, respectively.

From time to time, UGI Utilities sells natural gas or pipeline capacity to Energy Services. During Fiscal 2018, Fiscal 2017 and Fiscal 2016, revenues associated with such sales to Energy Services totaled $103.7 million, $50.9 million and $30.7 million, respectively. Also from time to time, UGI Utilities purchases natural gas, pipeline capacity and electricity from Energy Services (in addition to those transactions already described above) and purchases a firm storage service from UGI Storage Company, a subsidiary of Energy Services, under one-year agreements. During Fiscal 2018, Fiscal 2017 and Fiscal 2016, such purchases totaled $156.8 million, $84.4 million and $35.1 million, respectively.

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 retail core-market customers, including the cost of financial instruments used to hedge purchased gas costs. The recovery clauses provide for periodic adjustments for the difference between the total amounts actually collected from customers through purchased gas cost ("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, 2018, Gas Utility had $1.2 million of restricted cash in brokerage accounts. At September 30, 2018, the fair values of our natural gas futures and option contracts were gains of $2.9 million.

Electric Utility's DS tariffs contain clauses which permit recovery of all prudently incurred power costs, including the cost of financial instruments used to hedge electricity costs, through the application of default service ("DS") rates. Because of this ratemaking mechanism, there is limited power cost risk, including the cost of forward electricity purchase contracts, associated with our Electric Utility operations. At September 30, 2018, all of our Electric Utility's forward electricity purchase contracts were subject to the normal purchase and normal sale ("NPNS") exception.

In addition, Gas Utility and Electric Utility from time to time enter into exchange-traded gasoline futures contracts for a portion of gasoline volumes expected to be used in their operations. These gasoline futures contracts are recorded at fair value with changes in fair value reflected in "Operating and administrative expenses" on the Consolidated Statements of Income. The amount of unrealized gains on these contracts and associated volumes under contract at September 30, 2018 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 and UGI Utilities Term Loan. The Credit 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 2018, an increase in short-term interest rates of 100 basis points (1%) would have increased annual interest expense by approximately $1.8 million. The UGI Utilities' Term Loan also has a variable interest rate. In July 2018, UGI Utilities entered into a forward-starting, amortizing, pay-fixed, receive-variable interest rate swap that generally fixes the underlying prevailing market interest rates on Term Loan borrowings at approximately 3.00% beginning September 30, 2019 through July 2022.

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 $86 million at September 30, 2018. A 100 basis point decrease in market interest rates would result in increases in the fair value of this fixed-rate debt of approximately $105 million at September 30, 2018.

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"). There were no unsettled IRPAs outstanding at September 30, 2018.

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, which discusses the significant accounting policies that we have selected from acceptable alternatives.

Goodwill Impairment Evaluation. 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. 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. From time to time, we may assess qualitative factors to determine whether it is more likely than not that the fair value of such reporting unit is less than its carrying amount. From time to time, we may bypass the qualitative assessment and perform the quantitative assessment by comparing the fair values of the reporting units with their carrying amounts, including goodwill. We determine fair values 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 units. The market approach requires judgment to determine the appropriate valuation multiples. If the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized in an amount equal to such excess but not to exceed the total amount of the goodwill of the reporting unit. As of September 30, 2018, our goodwill totaled $182.1 million. We did not record any impairments of goodwill in Fiscal 2018, Fiscal 2017 or Fiscal 2016.

Litigation Accruals and Environmental Remediation Liabilities. We are involved in litigation that arises in the normal course of business. 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 record a reserve when it is probable that a liability exists and the amount or range of amounts related to such liability can be reasonably estimated. When there is a range of possible loss with equal likelihood, liabilities recorded are based upon the low end of such range. The likelihood of a loss with respect to a particular contingency is often difficult to predict and determining a reasonable estimate of the loss or a range of possible loss may not be practicable based upon the information available and the potential effects of future events and decisions by third parties that will determine the ultimate resolution of the contingency. Reasonable estimates involve management judgments based on a broad range of information and prior experience and include an evaluation of the nature of the claim, the procedural status of the matter, the probability or likelihood of success of prosecuting or defending the claim, the information available with respect to the claim, the opinions and views of outside counsel and other advisors, and past experience in similar matters. These judgments are reviewed quarterly as more information is received, and the amounts reserved are updated as necessary. Our estimated reserves may differ materially from the ultimate liability and such reserves may change materially as more information becomes available.

Regulatory Assets and Liabilities. Gas Utility and Electric Utility are subject to regulation by the PAPUC and with respect to Gas Utility, also the MDPSC. 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 PAPUC, 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, 2018, our regulatory assets and regulatory liabilities totaled $301.0 million and $390.2 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. Assets of the Pension Plan are held in trust and consist principally of equity and fixed income mutual funds and investments in UGI Corporation 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 6.80% would result in an increase in pre-tax pension cost of approximately $2.2 million in Fiscal 2019. A decrease in the discount rate of 50 basis points to a rate of 3.90% would result in an increase in pre-tax pension cost of approximately $3.4 million in Fiscal 2019. For additional information on our Pension Plan, see Note 9 to Consolidated Financial Statements.

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 Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. The Company’s management, with the participation of the Company’s Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company’s disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures, as of September 30, 2018, 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, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria").

Internal control over financial reporting refers to the process, designed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, and effected by the Company's Board of Directors, 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 GAAP and includes 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 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.

Based on its assessment, management has concluded that the Company's internal control over financial reporting was effective as of September 30, 2018, based on the COSO criteria. 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, 2018, 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 2018 and Fiscal 2017, were as follows:

	2018	2017
Audit Fees (1)	$ 1,162,172	$ 915,301
Audit-Related Fees (2)	97,496	480,458
Tax Fees (3)	5,731	71,926
All Other Fees (4)	28,601	66,711
Total Fees for Services Provided	$ 1,293,999	$ 1,534,396

(1) Audit fees for Fiscal 2018 and Fiscal 2017 were for audit services, including (i) the annual audit of the consolidated financial statements of the Company, (ii) regulatory-basis financial statements, and (iii) review of the interim financial statements included in the Quarterly Reports on Form 10-Q of the Company.
(2) Audit-Related Fees for Fiscal 2018 and 2017 related to pre-implementation reviews of the Company's new information technology system.
(3) Tax Fees for Fiscal 2018 and 2017 were for tax compliance or advisory services at the Company.
(4) All Other Fees for Fiscal 2018 and 2017 were for software license fees services provided for the implementation of ASC 606.

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. The Audit Committee has also delegated approval authority to its chair, such authority to be exercised in the intervals between meetings, in accordance with the Audit Committee’s pre-approval policy.

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

Consolidated Balance Sheets as of September 30, 2018 and 2017

Consolidated Statements of Income for the years ended September 30, 2018, 2017 and 2016

Consolidated Statements of Comprehensive Income for the years ended September 30, 2018, 2017 and 2016

Consolidated Statements of Cash Flows for the years ended September 30, 2018, 2017 and 2016

Consolidated Statements of Stockholder’s Equity for the years ended September 30, 2018, 2017 and 2016

Notes to Consolidated Financial Statements

(2) Financial Statement Schedule:

For the years ended September 30, 2018, 2017 and 2016

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, Inc., as amended and restated as of July 25, 2017.	Utilities	Form 8-K (7/25/17)	3.1
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' Amended and Restated Articles of Incorporation and Amended and Restated 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
4.12	Note Purchase Agreement dated April 22, 2016 between the Company and the purchasers listed as signatories thereto.	Utilities	Form 8-K (4/28/16)	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 September 5, 2014.	UGI	Form 10-K (9/30/16)	10.25
10.2**	UGI Corporation 2004 Omnibus Equity Compensation Plan Amended and Restated as of September 5, 2014 - Terms and Conditions as effective January 1, 2016.	UGI	Form 10-K (9/30/16)	10.26
10.3**	UGI Corporation 2013 Omnibus Incentive Compensation Plan, effective as of September 5, 2014.	UGI	Form 10-K (9/30/16)	10.30
10.4**	UGI Corporation 2013 Omnibus Incentive Compensation Plan, effective as of September 5, 2014 - Terms and Conditions for Non-Employee Directors effective January 1, 2016.	UGI	Form 10-K (9/30/16)	10.31
10.5**	UGI Corporation 2009 Deferral Plan, as Amended and Restated effective June 15, 2017.	UGI	Form 10-Q (6/30/17)	10.6
10.6**	UGI Corporation Senior Executive Employee Severance Plan, as amended and restated as of June 15, 2017.	UGI	Form 10-Q (6/30/17)	10.7
10.7**	UGI Corporation Supplemental Executive Retirement Plan and Supplemental Savings Plan, as Amended and Restated effective April 1, 2015.	UGI	Form 10-K (9/30/17)	10.26
10.8**	UGI Corporation 2009 Supplemental Executive Retirement Plan for New Employees, as Amended and Restated effective June 15, 2017.	UGI	Form 10-Q (6/30/17)	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 Utilities, Inc. Senior Executive Employee Severance Plan, as amended as of July 10, 2017.	Utilities	Form 10-Q (6/30/17)	10.1
10.11**	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
10.12**	Form of UGI Corporation 2013 Omnibus Incentive Compensation Plan Nonqualified Stock Option Grant Letter for UGI, Utilities and AmeriGas Employees, dated January 1, 2018.	Utilities	Form 10-Q (3/31/18)	10.1
10.13**	Form of UGI Corporation 2013 Omnibus Incentive Compensation Plan Performance Unit Grant Letter for UGI and Utilities Employees, dated January 1, 2018.	Utilities	Form 10-Q (3/31/18)	10.2
10.14	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
10.15	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
10.16	Gas Supply and Delivery Service Agreement between UGI Utilities, Inc. and UGI Energy Services, LLC, effective November 1, 2015.	Utilities	Form 10-K (9/30/16)	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 the other financial institutions from time to time parties thereto.	Utilities	Form 8-K (3/27/15)	10.1

Incorporation by Reference

Exhibit No.	Exhibit	Registrant	Filing	Exhibit
10.18	Credit Agreement, dated October 31, 2017, by and among UGI Utilities, Inc., PNC Bank National Association, as administrative agent, The Bank of New York Mellon, as syndication agent, and certain other lenders named therein.	Utilities	Form 8-K (10/31/17)	10.1
10.19	Increasing Lender Commitment and Acceptance, dated as of September 21, 2018, among UGI Utilities, Inc., as borrower, PNC Bank, National Association, as administrative agent, and each of the entities listed under the caption "Increasing Lenders" on the signature pages thereto.	Utilities	Form 8-K (9/21/18)	10.1

		Incorporation by Reference		
Exhibit No.	**Exhibit**	**Registrant**	**Filing**	**Exhibit**
14	Code of Ethics for principal executive, financial and accounting officers.	UGI	Form 10-K (9/30/03)	14
*23	Consent of Ernst & Young 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, 2018 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
*31.2	Certification by the Chief Financial Officer relating to the Registrant's Report on Form 10-K for the fiscal year ended September 30, 2018 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.			
*32	Certification by the Chief Executive Officer and the Chief Financial Officer relating to the Registrant's Report on Form 10-K for the fiscal year ended September 30, 2018, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
*101.INS	XBRL Instance			
*101.SCH	XBRL Taxonomy Extension Schema			
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase			
*101.DEF	XBRL Taxonomy Extension Definition Linkbase			
*101.LAB	XBRL Taxonomy Extension Labels Linkbase			
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase			

* Filed herewith.

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

ITEM 16. FORM 10-K SUMMARY

None.

EXHIBIT INDEX

Exhibit No.	Description
23	Consent of Ernst & Young LLP.
31.1	Certification by the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act
31.2	Certification by the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
32	Certification by the Chief Executive Officer and Chief 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

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 20, 2018	By: /s/ Daniel J. Platt
	Daniel J. Platt
	Vice President - Finance and Chief Financial Officer, Assistant Secretary and Treasurer (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on November 20, 2018 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/ Daniel J. Platt Daniel J. Platt	Vice President — Finance and Chief Financial Officer, Assistant Secretary and Treasurer (Principal Financial Officer)
/s/ Megan Mattern Megan Mattern	Controller (Principal Accounting Officer)
/s/ Marvin O. Schlanger Marvin O. Schlanger	Chairman and Director
/s/ John L. Walsh John L. Walsh	Vice Chairman and Director
/s/ M. Shawn Bort M. Shawn Bort	Director
/s/ Theodore A. Dosch Theodore A. Dosch	Director
/s/ Richard W. Gochnauer Richard W. Gochnauer	Director
/s/ Alan N. Harris Alan N. Harris	Director
/s/ Frank S. Hermance Frank S. Hermance	Director
/s/ Anne Pol Anne Pol	Director
/s/ James B. Stallings, Jr. James B. Stallings, Jr.	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 2018.

UGI UTILITIES, INC. AND SUBSIDIARIES

FINANCIAL INFORMATION

FOR INCLUSION IN ANNUAL REPORT ON FORM 10-K

YEAR ENDED SEPTEMBER 30, 2018

UGI UTILITIES, INC. AND SUBSIDIARIES

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

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

Opinion on Internal Control over Financial Reporting

We have audited UGI Utilities, Inc. and subsidiaries internal control over financial reporting as of September 30, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway (2013 framework) (the COSO criteria). In our opinion, UGI Utilities, Inc. and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of September 30, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of UGI Utilities, Inc. and subsidiaries as of September 30, 2018 and 2017, and the related consolidated statements of income, comprehensive income, stockholder's equity and cash flows for each of the three years in the period ended September 30, 2018, and the related notes and schedule and our report dated November 20, 2018, expressed an unqualified opinion thereon.

Basis for Opinion

The Company'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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control Over Financial Reporting

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 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.

/s/ Ernst & Young LLP
Philadelphia, Pennsylvania
November 20, 2018

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of UGI Utilities, Inc. and subsidiaries as of September 30, 2018 and 2017, the related consolidated statements of income, comprehensive income, stockholder's equity and cash flows for each of the three years in the period ended September 30, 2018, and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at September 30, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of September 30, 2018, 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 20, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2014.

Philadelphia, Pennsylvania
November 20, 2018

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

	September 30, 2018	September 30, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,314	$ 5,203
Restricted cash	1,190	3,046
Accounts receivable (less allowances for doubtful accounts of $9,760 and $4,052, respectively)	71,507	53,720
Accounts receivable — related parties	2,273	2,807
Accrued utility revenues	13,977	13,296
Inventories	52,413	53,309
Prepaid income taxes	53,857	7,711
Regulatory assets	7,475	8,338
Derivative instruments	3,004	1,354
Prepaid expenses	9,006	8,450
Other current assets	8,003	7,956
Total current assets	233,019	165,190
Property, plant and equipment	3,616,289	3,285,329
Less accumulated depreciation	(1,074,521)	(1,010,781)
Net property, plant and equipment	2,541,768	2,274,548
Goodwill	182,145	182,145
Regulatory assets	293,527	360,591
Other assets	16,117	11,541
Total assets	$ 3,266,576	$ 2,994,015
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 9,001	$ 39,996
Short-term borrowings	189,500	170,000
Accounts payable — trade	87,861	71,559
Accounts payable — related parties	9,585	6,890
Employee compensation and benefits accrued	19,081	21,851
Interest accrued	15,716	16,200
Customer deposits and advances	36,363	35,278
Derivative instruments	—	1,071
Regulatory liabilities	40,131	12,988
Other current liabilities	43,096	37,649
Total current liabilities	450,334	413,482
Long-term debt	828,995	711,105
Deferred income taxes	400,939	635,465
Deferred investment tax credits	2,631	2,950
Pension and other postretirement benefit obligations	81,590	143,674
Regulatory liabilities	350,044	36,242
Other noncurrent liabilities	58,755	63,192
Total liabilities	2,173,288	2,006,110
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	473,580	473,580
Retained earnings	579,778	480,857
Accumulated other comprehensive loss	(20,329)	(26,791)
Total common stockholder's equity	1,093,288	987,905
Total liabilities and stockholder's equity	$ 3,266,576	$ 2,994,015

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended September 30,		
	2018	2017	2016
Revenues	$ 1,092,381	$ 887,588	$ 768,484
Costs and expenses:			
Cost of sales — gas and purchased power (excluding depreciation shown below)	522,911	367,279	289,786
Operating and administrative expenses	235,334	215,645	196,631
Operating and administrative expenses — related parties	14,234	12,354	11,863
Depreciation	84,644	72,332	67,303
Other operating (income) expense, net	(2,264)	(8,329)	2,000
	854,859	659,281	567,583
Operating income	237,522	228,307	200,901
Interest expense	42,890	40,212	37,630
Income before income taxes	194,632	188,095	163,271
Income taxes	45,711	72,054	65,898
Net income	$ 148,921	$ 116,041	$ 97,373

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended September 30,		
	2018	2017	2016
Net income	$ 148,921	$ 116,041	$ 97,373
Net gains (losses) on derivative instruments (net of tax of $(10), $0 and $12,016, respectively)	20	—	(16,942)
Reclassifications of net losses on derivative instruments (net of tax of $(1,118), $(1,409) and $(1,112), respectively)	2,367	1,988	1,568
Benefit plans, principally actuarial gains (losses) (net of tax of $(1,512), $(1,336) and $2,267, respectively)	3,203	1,883	(3,197)
Reclassifications of benefit plans actuarial losses and net prior service benefits (net of tax of $(411), $(678) and $(454), respectively)	872	956	639
Other comprehensive income (loss)	6,462	4,827	(17,932)
Comprehensive income	$ 155,383	$ 120,868	$ 79,441

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended September 30,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 148,921	$ 116,041	$ 97,373
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	84,644	72,332	67,303
Deferred income taxes, net	61,934	78,568	76,938
Pension contributions, net of pension cost	(3,408)	4,017	1,580
Settlement of interest rate protection agreements	—	—	(35,975)
Provision for uncollectible accounts	17,970	8,030	7,760
Regulatory liability resulting from tax reform	24,430	—	—
Other, net	(3,778)	9,664	(10,112)
Net change in:			
Accounts receivable and accrued utility revenues	(35,903)	(25,253)	1,120
Inventories	896	(10,969)	9,376
Deferred fuel and power costs, net of changes in unsettled derivatives	31,077	(15,385)	(22,740)
Accounts payable	3,987	2,107	(3,053)
Prepaid income taxes	(46,146)	(5,755)	8,070
Other current assets	5,402	3,647	(8,140)
Other current liabilities	(1,409)	6,550	15,870
Net cash provided by operating activities	288,617	243,594	205,370
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for property, plant and equipment	(323,538)	(305,311)	(250,584)
Net costs of property, plant and equipment disposals	(10,061)	(12,735)	(7,940)
Decrease (increase) in restricted cash	1,856	(2,463)	6,019
Net cash used by investing activities	(331,743)	(320,509)	(252,505)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payment of dividends	(50,000)	(57,700)	(47,000)
Increase in short-term borrowings	19,500	57,500	40,800
Issuances of long-term debt, net of issuance costs	124,404	99,499	298,379
Repayments of long-term debt	(45,667)	(20,000)	(247,000)
Excess tax benefits from equity-based payment arrangements	—	—	1,676
Net cash provided by financing activities	48,237	79,299	46,855
Cash and cash equivalents increase (decrease)	$ 5,111	$ 2,384	$ (280)
CASH AND CASH EQUIVALENTS:			
End of year	$ 10,314	$ 5,203	$ 2,819
Beginning of year	5,203	2,819	3,099
Increase (decrease)	$ 5,111	$ 2,384	$ (280)
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid (received) for:			
Interest	$ 42,343	$ 29,449	$ 36,155
Income taxes	$ 24,306	$ 2,080	$ (19,758)

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,		
	2018	2017	2016
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	$ 480,857	$ 422,516	$ 372,143
Net income	148,921	116,041	97,373
Cash dividends — Common Stock	(50,000)	(57,700)	(47,000)
Balance, end of year	$ 579,778	$ 480,857	$ 422,516
Additional paid-in capital			
Balance, beginning of year	$ 473,580	$ 473,580	$ 471,904
Excess tax benefits on equity-based compensation	—	—	1,676
Balance, end of year	$ 473,580	$ 473,580	$ 473,580
Accumulated other comprehensive income (loss)			
Balance, beginning of year	$ (26,791)	$ (31,618)	$ (13,686)
Net gains (losses) on derivative instruments	20	—	(16,942)
Reclassifications of net losses on derivative instruments	2,367	1,988	1,568
Benefit plans, principally actuarial gains (losses)	3,203	1,883	(3,197)
Reclassifications of benefit plans actuarial losses and net prior service benefits	872	956	639
Balance, end of year	$ (20,329)	$ (26,791)	$ (31,618)
Total UGI Utilities, Inc. stockholder's equity	$ 1,093,288	$ 987,905	$ 924,737

See accompanying Notes to Consolidated Financial Statements.

1. NATURE OF OPERATIONS

UGI Utilities, Inc. ("UGI Utilities"), a wholly owned subsidiary of UGI Corporation ("UGI"), owns and operates a natural gas distribution utility business ("Gas Utility") directly and, prior to their merger with and into UGI Utilities effective October 1, 2018 (see Note 4), through its wholly owned subsidiaries UGI Penn Natural Gas, Inc. and UGI Central Penn Gas, Inc. The terms "PNG" and "CPG" are used herein as abbreviated references to UGI Penn Natural Gas, Inc. and UGI Central Penn Gas, Inc., respectively, or to their associated natural gas utilities. UGI Utilities' natural gas distribution utility is referred to as "UGI Gas." UGI Utilities also owns and operates an electric distribution utility in northeastern Pennsylvania ("Electric Utility"). Gas Utility is subject to regulation by the Pennsylvania Public Utility Commission ("PAPUC") and, with respect to a small service territory in one Maryland county, the Maryland Public Service Commission ("MDPSC"). Electric Utility is subject to regulation by the PAPUC and the Federal Energy Regulatory Commission ("FERC"). UGI Utilities is used herein as an abbreviated reference to UGI Utilities, Inc. or, collectively, UGI Utilities, Inc. and its subsidiaries.

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 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 intercompany accounts and transactions 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, "Regulated Operations." 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 and regulatory liabilities are amortized into expense and income over the periods 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, on a nonrecurring basis. Fair value in GAAP is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. 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 on the Consolidated Balance Sheets at their fair values, unless the normal purchase and normal sale (“NPNS”) exception is elected. The accounting for changes in fair value depends upon the purpose of the derivative instrument, whether it is subject to regulatory ratemaking mechanisms or if it qualifies and is designated as a hedge for accounting purposes.

Gains and losses on substantially all of the derivative instruments used by UGI Utilities to hedge commodity prices (for which NPNS has not been elected) are included in regulatory assets and liabilities. From time to time, we enter into derivative instruments that qualify and are designated as cash flow hedges. For cash flow hedges, changes in the fair values of the derivative financial instruments are recorded in accumulated other comprehensive income (loss) (“AOCI”), to the extent effective at offsetting changes in the hedged item, until earnings are affected by the hedged item. We discontinue cash flow hedge accounting if occurrence of the forecasted transaction is determined to be no longer probable. Hedge accounting is also discontinued for derivatives that cease to be highly effective. 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 rendered and commodities delivered 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 tax 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 UGI Utilities' plant additions over the service lives of the related property. UGI 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 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.

The Tax Cuts and Jobs Act ("TCJA") was enacted on December 22, 2017, and includes a broad range of tax reform provisions affecting the Company, including, among other things, changes in the U.S. corporate income tax rate. The TCJA reduces the corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. We are subject to a 24.5% blended U.S. federal income tax rate for Fiscal 2018 because our fiscal year contains the effective date of the rate change from 35% to 21%. In accordance with GAAP, at the date of enactment of the TCJA our federal deferred income taxes, including deferred income taxes related to items included in AOCI, were remeasured based upon the new corporate income tax rate. For further information regarding the impact of the TCJA, including the impact on our regulatory assets and liabilities, see Notes 4 and 8.

Cash and Cash Equivalents

For cash flow purposes, cash and cash equivalents include cash on hand, cash in banks and highly liquid investments with maturities of three months or less when purchased.

Restricted Cash

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

Inventories

Our inventories are stated at the lower of cost or net realizable value. We determine cost using an average cost method for substantially all of our inventory.

Property, Plant and Equipment and Related Depreciation

We record property, plant and equipment at original cost. Capitalized costs include labor, materials and other direct and indirect costs, and allowance for funds used during construction ("AFUDC"). 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 based upon projected service lives of the various classes of its depreciable property. The estimated useful lives of the classes of depreciable property are reviewed by a third party and adjusted, if necessary, as part of periodic service life studies required by the PAPUC. The average composite depreciation rates at our Gas Utility and Electric Utility for Fiscal 2018, 2017 and 2016 were as follows:

	2018	2017	2016
Gas Utility	2.3%	2.2%	2.2%
Electric Utility	2.2%	2.4%	2.5%

We include in property, plant and equipment costs associated with computer software we develop or obtain for use in our business. Information technology ("IT") costs associated with major system installations, conversions and improvements, such as software training, data conversion, business process reengineering costs, preliminary project stage costs and cloud computing are deferred as a regulatory asset and included as a component of property, plant and equipment. As of September 30, 2018, approximately $6,300 of these costs have been deferred as a regulatory asset and have not yet been requested in a rate proceeding. We amortize computer software and related IT system installation 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.

We classify amortization of computer software costs and IT regulatory assets included in property, plant and equipment as depreciation expense in the Consolidated Statements of Income.

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 five years, consistent with prior ratemaking treatment (See Note 4).

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. 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. From time to time, we may assess qualitative factors to determine whether it is more likely than not that the fair value of such reporting unit is less than its carrying amount. From time to time, we may bypass the qualitative assessment and perform the quantitative assessment by comparing the fair values of the reporting units with their carrying amounts, including goodwill. We determine fair values 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 our reporting units. The market approach requires judgment to determine the appropriate valuation multiples. If the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized in an amount equal to such excess but not to exceed the total amount of the goodwill of the reporting unit.

No provisions for goodwill impairments were recorded during Fiscal 2018, Fiscal 2017 or Fiscal 2016.

Impairment of Long-Lived Assets

We evaluate long-lived assets for impairment 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 2018, Fiscal 2017 or Fiscal 2016.

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 ("UGI 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. We account for forfeitures of equity-based payments when they occur.

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 be reasonably 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. Under GAAP, if the amount and timing of cash payments associated with environmental investigation and cleanup are reliably determinable, such liabilities are discounted to reflect the time value of money. We intend to pursue recovery of incurred costs through all appropriate means, including regulatory relief. UGI Utilities receives 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

New Accounting Standards Adopted Effective October 1, 2018

Revenue Recognition. In May 2014, the FASB issued Accounting Standards Update (“ASU”) No. 2014-09, “Revenue from Contracts with Customers” (“ASU 2014-09”). The guidance provided under this ASU, as amended, supersedes the revenue recognition requirements in ASC No. 605, “Revenue Recognition,” and most industry-specific guidance included in the ASC. ASU 2014-09 requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In addition, the new guidance requires enhanced disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers and requires, among other things, the disaggregation of revenues into categories that show how economic factors affect the nature, timing and uncertainty of revenues and cash flows. We adopted this ASU effective October 1, 2018, using the modified retrospective transition method.

The Company has completed the process of analyzing the impact of the new guidance using an integrated approach which includes evaluating differences in the amount and timing of revenue recognition from applying the requirements of the new guidance, reviewing its accounting policies and practices, and assessing the need for changes to its processes, accounting systems and design of internal controls. Although the impact of the adoption of the new revenue recognition guidance will not have a material impact on our financial statements, certain performance obligations associated the release of capacity contracts will be reflected on a gross, rather than net, basis beginning October 1, 2018, and revenues from certain other negotiated rate contracts will be reflected on a straight-line basis.

Cloud Computing Implementation Costs. In August 2018, the FASB issued ASU No. 2018-15, “Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract.” The new guidance requires a customer in a cloud computing arrangement that is a service contract to capitalize certain implementation costs as if the arrangement was an internal-use software project. These deferred implementation costs are expensed over the fixed, noncancelable term of the service arrangement plus any reasonably certain renewal periods. The new guidance also requires the entity to present the expense related to the capitalized implementation costs in the same income statement line as the hosting service fees; to classify payments for capitalized implementation costs in the statement of cash flows in the same manner as payments for hosting service fees; and to present the capitalized implementation costs in the balance sheet in the same line item in which prepaid hosting service fees are presented. The new guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We adopted this ASU effective October 1, 2018, and applied the guidance prospectively to all implementation costs associated with cloud computing arrangements that are service contracts incurred after October 1, 2018.

Stranded Tax Effects in Accumulated Other Comprehensive Income. In February 2018, the FASB issued ASU No. 2018-02, "Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income." This ASU provides that the stranded tax effects in AOCI resulting from the remeasurement of deferred income taxes associated with items included in AOCI due to the enactment of the TCJA may be reclassified to retained earnings, at the election of the entity, in the period the ASU is adopted. We adopted this ASU effective October 1, 2018. The amount of stranded tax benefits reclassified from AOCI to retained earnings as of October 1, 2018 was not material.

Pension and Other Postretirement Benefit Costs. In March 2017, the FASB issued ASU No. 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." This ASU requires entities to disaggregate the service cost component from the other components of net periodic benefit costs and present it with compensation costs for related employees in the income statement. The other components are required to be presented elsewhere in the income statement and outside of income from operations. The amendments in this ASU permit only the service cost component to be eligible for capitalization, when applicable. For entities subject to rate regulation, the ASU recognized that in the event a regulator continues to require capitalization of all net periodic benefit costs prospectively, the difference would result in the recognition of a regulatory asset or liability. Upon adoption, UGI Utilities will capitalize the non-service cost components of postretirement benefit costs as a regulatory asset. The new guidance became effective for us on October 1, 2018 with a retrospective adoption for income statement presentation and a prospective adoption for capitalization. Other than the presentation of the non-service cost components on the statement of income, the adoption of this new guidance will not have a material impact on our consolidated financial statements.

Statement of Cash flows - Restricted Cash. In November 2016, the FASB issued ASU No. 2016-18, "Statement of Cash Flows: Restricted Cash." The guidance in this ASU requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, as well as restricted cash or restricted cash equivalents. As a result, amounts generally described as restricted cash and restricted cash equivalents will be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts on the statement of cash flows. The amendments in the ASU are required to be adopted on a retrospective basis. We adopted this ASU effective October 1, 2018. Adoption of this new guidance will result in a change in presentation of restricted cash on the Consolidated Statement of Cash Flows; otherwise this guidance will not have a significant impact on our Consolidated Statement of Cash Flows and disclosures.

Other Accounting Principles Not Yet Adopted

Pension and Other Postretirement Benefit Costs Disclosures. In August 2018, the FASB issued ASU No. 2018-14, "Changes to the Disclosure Requirements for Defined Benefit Plans." This ASU modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans by removing and adding certain disclosures for these plans. The amendments in this ASU are effective for interim and annual periods ending after December 15, 2020 (Fiscal 2021). The guidance shall be adopted retrospectively for all periods presented in the financial statements. Early adoption is permitted. The Company is in the process of assessing the impact on its financial statement disclosures from the adoption of the new guidance and determining the period in which the new guidance will be adopted.

Fair Value Measurements Disclosures. In August 2018, the FASB issued ASU No. 2018-13, "Changes to the Disclosure Requirements for Fair Value Measurement." This ASU modifies the disclosure requirements for fair value measurements by removing, modifying, or adding certain disclosures. The amendments in this ASU are effective for annual periods beginning after December 15, 2019 (Fiscal 2021). The guidance regarding removed and modified disclosures will be adopted on a retrospective basis and the guidance regarding new disclosures will be adopted on a prospective basis. Early adoption is permitted. The Company is in the process of assessing the impact on its financial statement disclosures from the adoption of the new guidance and determining the period in which the new guidance will be adopted.

Derivatives and Hedging. In August 2017, the FASB issued ASU No. 2017-12, "Targeted Improvements to Accounting for Hedging Activities." This ASU amends and simplifies existing guidance to allow companies to more accurately present the economic effects of risk management activities in the financial statements. The amendments in this ASU are effective for the Company for interim and annual periods beginning October 1, 2019 (Fiscal 2020). Early adoption is permitted. For cash flow and net investment hedges as of the adoption date, the guidance requires a modified retrospective approach. The amended presentation and disclosure guidance is required only prospectively. The Company is in the process of assessing the impact on its financial statements from the adoption of the new guidance and determining the period in which the new guidance will be adopted.

Leases. In February 2016, the FASB issued ASU No. 2016-02, "Leases." This ASU, as subsequently updated, amends existing guidance to require entities that lease assets to recognize the assets and liabilities for the rights and obligations created by those leases on the balance sheet. The new guidance also requires additional disclosures about the amount, timing and uncertainty of cash flows from leases. The amendments in this ASU are effective for the Company for interim and annual periods beginning October 1, 2019 (Fiscal 2020). Early adoption is permitted. Lessees must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements unless an entity chooses the transition option in ASU 2018-11, “Leases: Targeted Improvements” which, among other things, provides entities with a transition option to recognize the cumulative-effect adjustment from the modified retrospective application to the opening balance of retained earnings in the period of adoption. We will adopt ASU No. 2016-02, as updated, effective October 1, 2019 and expect to adopt the transition option which would allow the Company to maintain historical presentation for periods before October 1, 2019. The Company has completed a preliminary assessment for evaluating the impact of the guidance and anticipates that its adoption will result in a significant amount of right-of-use assets and lease liabilities for leases in effect at the adoption date. The Company has begun implementation activities including accumulating contracts and lease data in formats compatible with a new lease management system that will assist with the initial adoption of the standard.

4. REGULATORY ASSETS AND LIABILITIES AND REGULATORY MATTERS

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

	2018	2017
Regulatory assets:		
Income taxes recoverable	$ 110,129	$ 121,421
Underfunded pension and postretirement plans	87,106	141,310
Environmental costs	58,836	61,566
Deferred fuel and power costs	—	7,685
Removal costs, net	32,025	30,996
Other	12,906	5,951
Total regulatory assets	$ 301,002	$ 368,929
Regulatory liabilities:		
Postretirement benefits overcollections	$ 17,781	$ 17,493
Deferred fuel and power refunds	36,723	10,621
State income tax benefits — distribution system repairs	22,611	18,430
PAPUC temporary rates order (a)	24,430	—
Excess federal deferred income taxes (b)	285,221	—
Other	3,409	2,686
Total regulatory liabilities	$ 390,175	$ 49,230

(a) Balance at September 30, 2018, comprises tax savings for the period January 1, 2018 to June 30, 2018, plus interest, resulting from the enactment of the TCJA (see “PAPUC Temporary Rates Order” below and Note 8).
(b) Balance at September 30, 2018, comprises excess federal deferred income taxes resulting from the enactment of the TCJA (see “Excess federal deferred income taxes” below and Note 8).

Other than removal costs, UGI Utilities currently does not recover a rate of return on the regulatory assets included in the table above.

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. UGI 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 net actuarial losses and prior service costs (credits) 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 principally represent estimated probable future environmental remediation and investigation costs that Gas Utility expects to incur, primarily at Manufactured Gas Plant ("MGP") sites in Pennsylvania, in conjunction with remediation consent orders and agreements with the Pennsylvania Department of Environmental Protection ("PADEP"). Pursuant to base rate orders, Gas Utility receives ratemaking recognition of its estimated environmental investigation and remediation costs associated with their environmental sites. This ratemaking recognition balances the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites. At September 30, 2018, the period over which Gas Utility expects to recover these costs will depend upon future remediation activity. For additional information on environmental costs, see Note 12.

Removal costs, net. This regulatory asset represents costs incurred, net of salvage, associated with the retirement of depreciable utility plant. As required by PAPUC ratemaking, removal costs include actual costs incurred associated with asset retirement obligations. Consistent with prior ratemaking treatment, Gas Utility expects to recover these costs over five years.

***Postretirement benefit overcollections*.** This regulatory liability represents the difference between amounts recovered through rates by Gas Utility and Electric Utility and actual costs incurred in accordance with accounting for postretirement benefits. With respect to Gas Utility, postretirement benefit overcollections are generally being refunded to customers over a ten-year period beginning October 19, 2016, the date UGI Gas' Joint Petition pursuant to its January 19, 2016 base rate filing became effective (see "Base Rate Filings" below). With respect to Electric Utility, the overcollections will be refunded to ratepayers over a 20-year period effective October 27, 2018.

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

Gas Utility uses derivative instruments to reduce volatility in the cost of gas it purchases for firm- residential, commercial and industrial ("retail core-market") customers. Realized and unrealized gains or losses on natural gas derivative instruments are included in deferred fuel costs or refunds. Net unrealized gains on such contracts at September 30, 2018 and 2017, were $2,856 and $146, respectively.

State income tax benefits — distribution system repairs. This regulatory liability represents Pennsylvania state income tax benefits, net of federal benefit, 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.

PAPUC Temporary Rates Order. By Secretarial Letter dated January 12, 2018, the PAPUC initiated a review into whether public utility rates should be adjusted to reflect the tax savings from the change in the federal income tax rate from 35% to 21% for the period beginning January 1, 2018. Thereafter, on March 15, 2018, the PAPUC entered a Temporary Rates Order that converted commission-approved rates of most large Pennsylvania public utilities, including Gas Utility, into "temporary rates" for a period of no more than 12 months while the PAPUC reviewed the data and comments in response to the Secretarial Letter.

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

In its May 17, 2018 Order, the PAPUC also required Pennsylvania utilities to establish a regulatory liability for tax benefits that accrued during the period beginning January 1, 2018 through June 30, 2018, resulting from the reduced federal tax rate. Gas Utility reduced its combined utility revenues by $24,098, and recorded a regulatory liability in an equal amount. The total reduction in revenues Fiscal 2018 reflects (1) $17,135 of tax benefits accrued during the previously mentioned six-month period plus (2) $6,963 to reflect tax benefits expected to be generated by the future amortization of the regulatory liability. The rate treatment of this regulatory liability, plus accrued interest, for each Gas Utility rate district will be addressed in a future proceeding and the Company cannot predict the ultimate treatment of this liability. Like other similarly situated utilities, if Gas Utility has not filed a general base rate proceeding within three years of the Temporary Rates Order, Gas Utility will be required to file a petition to propose how to distribute the balance of these regulatory liabilities.

For Pennsylvania utilities that were in a general base rate proceeding, including Electric Utility, no negative surcharge will apply. The tax benefits that accrued during the period January 1, 2018 through October 26, 2018, the date before Electric Utility's base rate case became effective (see below), will be refunded to Electric Utility ratepayers through a one-time bill credit.

Excess federal deferred income taxes. This regulatory liability is the result of remeasuring UGI Utilities' federal deferred income tax liabilities on utility plant due to the enactment of the TCJA on December 22, 2017 (see Note 8). In order for our utility assets to continue to be eligible for accelerated tax depreciation, current law requires that excess federal deferred income taxes resulting from the remeasurement be amortized no more rapidly than over the remaining lives of the assets that gave rise to the excess federal deferred income taxes, ranging from 1 year to approximately 65 years. This regulatory liability has been increased to reflect the tax benefit generated by the amortization of the excess deferred federal income taxes and is being amortized and credited to tax expense.

Other. Other regulatory assets and liabilities comprise a number of deferred items including, among others, over or under refunds of tax benefits related to TCJA for periods after June 30, 2018, certain information technology costs, energy efficiency conservation costs and rate case expenses.

Other Regulatory Matters

Utilities Merger. On March 8, 2018 and March 13, 2018, the Company filed merger authorization requests with the PAPUC and MDPSC, respectively, to merge PNG and CPG into UGI Utilities, with a targeted effective date of October 1, 2018. After receiving all necessary Federal Energy Regulatory Commission ("FERC"), MDPSC, and PAPUC approvals, CPG and PNG were merged into UGI Utilities effective October 1, 2018. Consistent with the MDPSC order issued July 25, 2018, and the PAPUC order issued September, 26, 2018, the former CPG, PNG and UGI Utilities, Inc. Gas Division service territories, respectively, became the UGI Central, UGI North and UGI South rate districts of the UGI Utilities, Inc. Gas Division, without any ratemaking changes. The Company's obligations under the settlement approved by the PAPUC include various non-monetary conditions requiring the Company to maintain separate accounting-type schedules for limited future ratemaking purposes.

Base Rate Filings. On January 26, 2018, Electric Utility filed a rate request with the PAPUC to increase its annual base distribution revenues by $9,200, which was later reduced by the Company to $7,700 to reflect the impact of the TCJA and other adjustments. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable electric service. On October 25, 2018, the PAPUC approved a final order providing for a $3,201 annual base distribution rate increase for Electric Utility. The increase became effective on October 27, 2018. As part of the final order, the Company is required to provide customers with a one-time $210 billing credit associated with 2018 TCJA tax benefits.

On January 19, 2017, PNG (now the UGI North rate district of Gas Utility) filed a rate request with the PAPUC to increase PNG's annual base operating revenues for residential, commercial and industrial customers by $21,700 annually. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. On June 30, 2017, all active parties supported the filing of a Joint Petition for Approval of Settlement of all issues with the PAPUC providing for an $11,250 PNG annual base distribution rate increase. On August 31, 2017, the PAPUC approved the Joint Petition and the increase became effective on October 20, 2017.

On January 19, 2016, UGI Utilities (now the UGI South rate district of Gas Utility) filed a rate request with the PAPUC to increase UGI Gas's annual base operating revenues for residential, commercial and industrial customers by $58,600. The increased revenues would fund ongoing system improvements and operations necessary to maintain safe and reliable natural gas service. On June 30, 2016, a Joint Petition for Approval of Settlement of all issues providing for a $27,000 UGI Gas annual base distribution rate increase, to be effective October 19, 2016, was filed with the PAPUC ("Joint Petition"). On October 14, 2016, the PAPUC approved the Joint Petition with minor modification which had no effect on the $27,000 base distribution rate increase. The increase became effective on October 19, 2016.

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

PNG and CPG received PAPUC approval on a DSIC tariff, initially set at zero, in 2014. PNG and CPG began charging a DSIC at a rate other than zero, beginning on April 1, 2015 and April 1, 2016, respectively. In May 2017, the PAPUC issued a final Order to approve an increase of the maximum allowable DSIC to 7.5% of billed distribution revenues effective July 1, 2017, for PNG and CPG, pending reconsideration at each company's Long-Term Infrastructure Improvement Plan filing. PNG's DSIC has been reset to zero as a result of its most recent base rate case. The DSIC rate for PNG will resume under the UGI North rate district upon exceeding the threshold amount of DSIC-eligible plant in service agreed upon in the settlement of its most recent base rate case.

In November 2016, UGI Gas received PAPUC approval to establish a DSIC tariff mechanism, capped at 5% of distribution charges billed to customers, effective January 1, 2017. UGI Gas began recovering revenue under the mechanism effective July 1, 2018, as it exceeded the threshold amount of DSIC-eligible plant agreed upon in the settlement of its recent base rate case during the third quarter of Fiscal 2018.

Manor Township, Pennsylvania Natural Gas Incident Complaint. In connection with a July 2, 2017, explosion in Manor Township, Lancaster County, PA, that resulted in the death of one Company employee and injuries to two Company employees and one sewer authority employee, and destroyed two residences and damaged several other homes, the PAPUC Bureau of Investigation and Enforcement ("BIE") filed a formal complaint at the PAPUC in which BIE alleges that the Company committed multiple violations of federal and state gas pipeline regulations in connection with its emergency response leading up to the explosion, and requested that the PAPUC order the Company to pay approximately $2,100 in civil penalties which is the maximum allowable fine. On November 16, 2018, the Company filed its formal written answer contesting the BIE complaint.

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

5. INVENTORIES

Inventories comprise the following at September 30:

	2018	2017
Gas Utility natural gas	$ 37,287	$ 39,486
Materials, supplies and other	15,126	13,823
Total inventories	$ 52,413	$ 53,309

At September 30, 2018, UGI Utilities was a party to five principal storage contract administrative agreements ("SCAAs") having terms ranging from one to three years. Four of the SCAAs were with UGI Energy Services, LLC ("Energy Services"), a second-tier, wholly owned subsidiary of UGI (see Note 18), and one of the SCAAs was with a non-affiliate. Pursuant to SCAAs, UGI Utilities has, among other things, released certain storage and transportation contracts for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon commencement of the SCAAs, will receive a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the terms of the SCAAs. The historical cost of natural gas storage inventories released under the SCAAs, which represents a portion of Gas Utility's total natural gas storage inventories, and any exchange receivable (representing amounts of natural gas inventories used by the other parties to the agreement but not yet replenished for which UGI Utilities has the rights), are included in the caption "Gas Utility natural gas" in the table above.

The carrying values of gas storage inventories released under the SCAAs at September 30, 2018 and 2017, comprising 9.0 billion cubic feet ("bcf") and 9.1 bcf of natural gas, were $23,136 and $26,064, respectively. At September 30, 2018 and 2017, UGI Utilities held a total of $13,840 and $15,040, respectively, of security deposits received from its SCAA counterparties. These amounts are included in "Other current liabilities" on the Consolidated Balance Sheets.

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:

	2018	2017
Distribution	$ 3,106,599	$ 2,835,339
Transmission	97,075	96,430
Computer equipment and software	127,201	113,017
Construction in process	130,893	112,563
General and other	154,521	127,980
Total property, plant and equipment	$ 3,616,289	$ 3,285,329

7. DEBT

Long-term debt comprises the following at September 30:

	2018	2017
Senior Notes:		
4.12%, due September 2046	$ 200,000	$ 200,000
4.98%, due March 2044	175,000	175,000
4.12%, due October 2046	100,000	100,000
6.21%, due September 2036	100,000	100,000
2.95%, due June 2026	100,000	100,000
Medium-Term Notes:		
7.25%, due November 2017	—	20,000
5.67%, due January 2018	—	20,000
6.50%, due August 2033	20,000	20,000
6.13%, due October 2034	20,000	20,000
Variable-rate term loan, due through October 2022	120,313	—
Capital lease obligations	6,817	—
Total long-term debt	842,130	755,000
Less: unamortized debt issuance costs	(4,134)	(3,899)
Less: current maturities	(9,001)	(39,996)
Total long-term debt due after one year	$ 828,995	$ 711,105

Scheduled principal repayments of long-term debt for each of the next five fiscal years ending September 30 are as follows: $9,001 is due in Fiscal 2019; $8,225 is due in Fiscal 2020; $7,841 is due in Fiscal 2021; $6,751 is due in Fiscal 2022; and $95,313 is due in Fiscal 2023.

In April 2016, UGI Utilities entered into a Note Purchase Agreement (the "2016 Note Purchase Agreement") with a consortium of lenders. Pursuant to the 2016 Note Purchase Agreement, UGI Utilities issued $100,000 aggregate principal amount of 2.95% Senior Notes due June 2026 and $200,000 aggregate principal amount of 4.12% Senior Notes due September 2046 in June 2016 and September 2016, respectively. In October 2016, UGI Utilities issued $100,000 aggregate principal amount of 4.12% Senior Notes due October 2046 (the "4.12% Senior Notes"). The net proceeds of the issuance of these senior notes were used (1) to repay UGI Utilities' maturing 5.75% Senior Notes, 7.37% Medium-term Notes and 5.64% Medium-term Notes; (2) to provide additional financing for UGI Utilities' infrastructure replacement and betterment capital program and IT initiatives and (3) for general corporate purposes. These senior notes are unsecured and rank equally with UGI Utilities' existing outstanding senior debt.

In October 2017, UGI Utilities entered into a $125,000 unsecured variable-rate term loan agreement (the "Term Loan") with a group of banks. Proceeds from the Term Loan were used to repay revolving credit agreement borrowings and for general corporate purposes. The Term Loan is payable in equal quarterly installments of $1,563, commencing in March 2018, with the balance of the principal being due and payable in full on October 30, 2022. Under the Term Loan, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.875% and is based upon the credit ratings of certain indebtedness of UGI Utilities. The Term Loan requires that UGI Utilities not exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined. In July 2018, UGI Utilities entered into forward-starting pay-fixed, receive-variable interest rate swap that generally fixes the underlying prevailing market interest rates on Term Loan borrowings at approximately 3.00% through July 2022. This forward-starting interest rate swap commences September 30, 2019. We have designated this forward-starting interest rate swap as a cash flow hedge. The effective interest rate on this term loan at September 30, 2018, was 2.76%.

In September 2018, UGI Utilities entered into an Increasing Lender Commitment and Acceptance (the "Commitment and Acceptance") under its existing unsecured, revolving credit agreement (the "Credit Agreement"). The Commitment and Acceptance increases the amount of loan commitments under the Credit Agreement to $450,000 from $300,000. After entering into the Commitment and Acceptance, the Credit Agreement provides for borrowings of up to $450,000 (including a $100,000 sublimit for letters of credit) and expires in March 2020. 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 Agreement, which we classify as "Short-term borrowings" on the Consolidated Balance Sheets, totaling $189,500 and $170,000 at September 30, 2018 and 2017, respectively. The weighted-average interest rates on the credit agreement borrowings at September 30, 2018 and 2017 were 3.03% and 2.11%, respectively. Issued and outstanding letters of credit, which reduce available borrowings under the credit agreements, totaled $2,000 and $2,009 at September 30, 2018 and 2017, respectively.

Restrictive Covenants. Certain of UGI Utilities 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. These 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 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:

	2018	2017	2016
Current expense (benefit):			
Federal	$ (26,952)	$ (12,253)	$ (17,845)
State	10,729	5,739	6,805
Total current (benefit) expense	(16,223)	(6,514)	(11,040)
Deferred expense (benefit):			
Federal	60,766	70,293	71,005
State	1,486	8,593	6,262
Investment tax credit amortization	(318)	(318)	(329)
Total deferred expense	61,934	78,568	76,938
Total income tax expense	$ 45,711	$ 72,054	$ 65,898

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

	2018	2017	2016
U.S. federal statutory tax rate	24.5 %	35.0 %	35.0%
Difference in tax rate due to:			
State income taxes, net of federal benefit	4.7	5.0	5.2
Effect of tax rate changes - TCJA	(3.8)	—	—
Excess tax benefits on share-based payments	(0.5)	(0.9)	—
Other, net	(1.4)	(0.8)	0.2
Effective tax rate	23.5 %	38.3 %	40.4%

On December 22, 2017, the TCJA was enacted into law. The significant changes resulting from the law that impacted UGI Utilities included a reduction in the U.S. federal income tax rate from 35% to 21%, effective January 1, 2018 (resulting in a blended rate of 24.5% for Fiscal 2018) and eliminated bonus depreciation on regulated utility property beginning in Fiscal 2019.

As a result of the TCJA, we reduced our net deferred income tax liabilities by $296,677 during Fiscal 2018 due to the remeasuring of our existing federal deferred income tax assets and liabilities from 35% to 21%. Because a significant amount of the reduction relates to our regulated utility plant assets, most of the reduction to our deferred income taxes is not being recognized immediately in income tax expense. For the fiscal year ended September 30, 2018, the amount of the reduction in our net deferred income tax liabilities that reduced income tax expense, including adjustments to provisional amounts previously recorded, totaled $7,315.

At September 30, 2018, the accounting for certain income tax effects of the TCJA with respect to existing deferred tax balances reflect provisional amounts. We have made a reasonable estimate of the effects in accordance with U.S. Securities and Exchange Commission Staff Accounting Bulletin No. 118 and are still analyzing certain aspects of the TCJA and refining our calculations, which could potentially result in changes to our current estimates. Revisions to our estimates, if any, will be made by the first quarter of the fiscal year ending September 30, 2019.

In order for utility assets to continue to be eligible for accelerated tax depreciation, current law requires that excess deferred federal income taxes resulting from the measurement of deferred taxes on regulated utility plant be amortized no more rapidly than over the remaining lives of the assets that gave rise to the excess deferred income taxes. For Fiscal 2018, we initially recorded a net regulatory liability of $205,759 associated with the excess deferred federal income taxes related to our regulated utility plant assets. This regulatory liability was increased, and a federal deferred income tax asset recorded, in the amount of $83,603 to reflect the tax benefit generated by the amortization of the excess deferred federal income taxes. This regulatory liability is being amortized to income tax expense over the remaining lives of the assets that gave rise to the excess deferred income taxes. For further information on these regulatory assets and liabilities, see Note 4.

As further described in Note 4, on May 17, 2018, the PUC issued a Temporary Rates Order for all PUC-regulated utilities with regard to the TCJA. Among other things, the Temporary Rates Order required Pennsylvania utilities to establish a regulatory liability for tax benefits that accrued during the period January 1, 2018 through June 30, 2018, resulting from the change in the federal income tax rate from 35% to 21%. In order to reflect the effects of the tax savings from the change in the federal income tax rate for the period January 1, 2018 to June 30, 2018, during Fiscal 2018, UGI Utilities reduced its combined utility revenues by $24,098, and recorded a regulatory liability in an equal amount. The reduction reflects (1) $17,135 of tax benefits accrued during the period January 1, 2018, to June 30, 2018, plus (2) $6,963 to reflect tax benefits expected to be generated by the future amortization of the regulatory liability.

Pennsylvania utility ratemaking practice permits the flow through to ratepayers of state tax benefits resulting from accelerated tax depreciation. For Fiscal 2018, Fiscal 2017 and Fiscal 2016, the beneficial effects of state tax flow through of accelerated depreciation reduced tax expense by $4,211, $2,537 and $1,344, respectively.

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

	2018	2017
Excess book basis over tax basis of property, plant and equipment	$ 441,154	$ 564,327
Goodwill	37,414	49,588
Derivative financial instruments	579	—
Regulatory assets	90,022	136,093
Other	3,375	3,140
Gross deferred tax liabilities	572,544	753,148
Pension plan liabilities	(19,831)	(57,011)
Allowance for doubtful accounts	(2,820)	(1,681)
Deferred investment tax credits	(760)	(1,224)
Employee-related expenses	(4,581)	(6,793)
Regulatory liabilities	(118,506)	(12,780)
Environmental liabilities	(14,551)	(22,224)
Derivative financial instruments	—	(354)
Other	(10,571)	(15,616)
Gross deferred tax assets	(171,620)	(117,683)
Net deferred tax liabilities	$ 400,924	$ 635,465

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 2014.

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 2018, Fiscal 2017 and Fiscal 2016, interest expense (income) of $6, $(73) and $204, respectively, was recognized in income taxes in the Consolidated Statements of Income.

As of September 30, 2018, we have unrecognized income tax benefits totaling $688 including related accrued interest of $6. If these unrecognized tax benefits were subsequently recognized, $688 would be recorded as a benefit to income taxes on the Consolidated Statement of Income and, therefore, would impact the reported effective tax rate. Generally, a net reduction in unrecognized tax benefits could occur because of the expiration of the statute of limitations in certain jurisdictions or as a result of settlements with tax authorities. There is no material change expected in unrecognized tax benefits and related interest in the next twelve months.

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

	2018	2017	2016
Unrecognized tax benefits – beginning of year	$ 1,829	$ 2,055	$ —
Additions for tax positions taken in prior years	6	604	2,055
Settlements with tax authorities/statute lapses	(1,147)	(830)	—
Unrecognized tax benefits – end of year	$ 688	$ 1,829	$ 2,055

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 limited postretirement health care benefits to certain retirees and postretirement life insurance benefits to certain active and retired employees ("Other Postretirement Plans").

The following table provides a reconciliation of the projected benefit obligations ("PBOs") of the Pension Plan, the accumulated benefit obligations ("ABOs") of the Other Postretirement Plans, plan assets and the funded status of the Pension Plan and Other Postretirement Plans as of September 30, 2018 and 2017. 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	
	2018	2017	2018	2017
Change in benefit obligations:				
Benefit obligations — beginning of year	$ 639,245	$ 645,444	$ 11,904	$ 12,075
Service cost	8,469	9,038	147	303
Interest cost	25,358	24,394	448	460
Actuarial gain	(36,050)	(14,575)	(1,348)	(512)
Benefits paid	(25,831)	(25,056)	(467)	(422)
Benefit obligations — end of year	$ 611,191	$ 639,245	$ 10,684	$ 11,904
Change in plan assets:				
Fair value of plan assets — beginning of year	$ 498,080	$ 463,432	$ 14,771	$ 13,715
Actual gain on assets	44,408	48,309	913	1,333
Employer contributions	15,079	11,395	—	85
Benefits paid	(25,831)	(25,056)	(335)	(362)
Fair value of plan assets — end of year	$ 531,736	$ 498,080	$ 15,349	$ 14,771
Funded status of the plans — end of year	$ (79,455)	$ (141,165)	$ 4,665	$ 2,867
Assets (liabilities) recorded in the balance sheet:				
Assets in excess of liabilities – included in other noncurrent assets	$ —	$ —	$ 6,729	$ 5,382
Unfunded liabilities – included in other noncurrent liabilities	(79,455)	(141,165)	(2,064)	(2,514)
Net amount recognized	$ (79,455)	$ (141,165)	$ 4,665	$ 2,868
Amounts recorded in stockholder's equity (pre-tax):				
Prior service cost (benefit)	$ 80	$ 105	$ (12)	$ (23)
Net actuarial loss (gain)	9,490	15,106	(368)	(46)
Total	$ 9,570	$ 15,211	$ (380)	$ (69)
Amounts recorded in regulatory assets and liabilities (pre-tax):				
Prior service cost (benefit)	$ 720	$ 970	$ (1,163)	$ (1,605)
Net actuarial loss (gain)	85,746	139,505	(135)	1,192
Total	$ 86,466	$ 140,475	$ (1,298)	$ (413)

In Fiscal 2019, we estimate that we will amortize approximately $7,000 of net actuarial losses, primarily associated with Pension Plan, and $200 of net prior service benefits 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:	2018	2017	2016	2018	2017	2016
Discount rate – benefit obligations	4.40%	4.00%	3.80%	4.40%	4.00%	3.80%
Discount rate – benefit cost	4.00%	3.80%	4.60%	4.00%	3.80%	4.70%
Expected return on plan assets	7.40%	7.50%	7.55%	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 $572,801 and $605,237 as of September 30, 2018 and 2017, respectively. Included in the end of year Pension Plan PBOs above are $60,904 at September 30, 2018, and $62,458 at September 30, 2017, relating to employees of UGI and certain of its other subsidiaries. Included in the end of year Other Postretirement Plans ABOs above are $880 at September 30, 2018, and $996 at September 30, 2017, 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		
	2018	2017	2016	2018	2017	2016
Service cost	$ 7,525	$ 8,091	$ 6,927	$ 267	$ 273	$ 183
Interest cost	23,067	22,157	23,270	447	431	465
Expected return on assets	(31,107)	(29,986)	(28,668)	(709)	(656)	(596)
Amortization of:						
Prior service cost (benefit)	250	325	348	(440)	(641)	(641)
Actuarial loss	11,936	14,825	9,571	94	108	98
Net benefit cost (benefit)	11,671	15,412	11,448	(341)	(485)	(491)
Change in associated regulatory liabilities	—	—	—	(490)	(490)	971
Net benefit cost (benefit) after change in regulatory liabilities	$ 11,671	$ 15,412	$ 11,448	$ (831)	$ (975)	$ 480

Pension Plan assets are held in trust and consist principally of publicly traded, diversified equity and fixed income mutual funds and, to a much lesser extent, UGI Common Stock. It is our general policy to fund amounts for Pension Plan benefits equal to at least the minimum contribution required by ERISA. From time to time we may, at our discretion, contribute additional amounts. During Fiscal 2018, Fiscal 2017 and Fiscal 2016, we made contributions to the Pension Plan of $15,079, $11,395 and $9,869, respectively. The minimum required contributions in Fiscal 2019 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, if any, is deferred for future recovery from, or refund to, ratepayers. The required contributions to the VEBA during Fiscal 2019, 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 2019	$ 28,183	$ 556
Fiscal 2020	29,602	544
Fiscal 2021	30,889	529
Fiscal 2022	32,166	531
Fiscal 2023	33,567	518
Fiscal 2024 - 2028	185,205	2,683

Because the postretirement health care benefit generally comprises a fixed amount per covered participant, changes in health care cost trend rates would not impact other postretirement benefit costs or the September 30, 2018, other postretirement benefit ABO.

We also sponsor unfunded and non-qualified supplemental executive defined benefit retirement income plans. At September 30, 2018 and 2017, the PBOs of these plans were $3,803 and $4,222, respectively. We recorded expense for these plans of $355 in Fiscal 2018, $605 in Fiscal 2017 and $353 in Fiscal 2016.

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 index mutual funds 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:	2018	2017	Allocation	Range
Equity investments:				
Domestic	58.2%	55.2%	52.5%	40.0% – 65.0%
International	11.8%	12.4%	12.5%	7.5% – 17.5%
Total	70.0%	67.6%	65.0%	60.0% – 70.0%
Fixed income funds & cash equivalents	30.0%	32.4%	35.0%	30.0% – 40.0%
Total	100.0%	100.0%	100.0%	

	Actual		Target Asset	Permitted
VEBA:	2018	2017	Allocation	Range
Domestic equity investments	65.6%	63.1%	65.0%	60.0% – 70.0%
Fixed income funds & cash equivalents	34.4%	36.9%	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 mid- and small-cap index mutual funds. 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 8.5% and 7.7% of Pension Plan assets at September 30, 2018 and 2017, 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 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, 2018 and 2017 are as follows:

	Pension Plan				
	Level 1	Level 2	Level 3	Other[(a)]	Total
September 30, 2018:					
Domestic equity investments:					
S&P 500 Index equity mutual funds	$ 188,437	$ —	$ —	$ —	$ 188,437
Small and midcap equity mutual funds	75,675	—	—	—	75,675
UGI Corporation Common Stock	45,152	—	—	—	45,152
Total domestic equity investments	309,264	—	—	—	309,264
International index equity mutual funds	62,907	—	—	—	62,907
Fixed income investments:					
Bond index mutual funds	154,345	—	—	—	154,345
Cash equivalents	—	—	—	5,198	5,198
Total fixed income investments	154,345	—	—	5,198	159,543
Total	$ 526,516	$ —	$ —	$ 5,198	$ 531,714
September 30, 2017:					
Equity investments:					
S&P 500 Index equity mutual funds	$ 171,600	$ —	$ —	$ —	$ 171,600
Small and midcap equity mutual funds	65,167	—	—	—	65,167
UGI Corporation Common Stock	38,137	—	—	—	38,137
Total domestic equity investments	274,904	—	—	—	274,904
International index equity mutual funds	61,613	—	—	—	61,613
Fixed income investments:					
Bond index mutual funds	156,228	—	—	—	156,228
Cash equivalents	—	—	—	5,332	5,332
Total fixed income investments	156,228	—	—	5,332	161,560
Total	$ 492,745	$ —	$ —	$ 5,332	$ 498,077

	VEBA				
	Level 1	Level 2	Level 3	Other[(a)]	Total
September 30, 2018:					
S&P 500 Index equity mutual fund	$ 10,074	$ —	$ —	$ —	$ 10,074
Bond index mutual fund	4,973	—	—	—	4,973
Cash equivalents	—	—	—	301	301
Total	$ 15,047	$ —	$ —	$ 301	$ 15,348
September 30, 2017:					
S&P 500 Index equity mutual fund	$ 9,318	$ —	$ —	$ —	$ 9,318
Bond index mutual fund	5,044	—	—	—	5,044
Cash equivalents	—	—	—	409	409
Total	$ 14,362	$ —	$ —	$ 409	$ 14,771

(a) Assets measured at net asset value ("NAV") and therefore excluded from the fair value hierarchy.

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 $3,391 in Fiscal 2018, $2,829 in Fiscal 2017 and $2,409 in Fiscal 2016. 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 2018, Fiscal 2017 and Fiscal 2016.

10. SERIES PREFERRED STOCK

The Company has 2,000,000 shares of Series Preferred Stock authorized for issuance, including both series subject to and series not subject to mandatory redemption. The Company had no shares of Series Preferred Stock outstanding at September 30, 2018 or 2017.

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 UGI 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 the Russell Midcap Utility Index, excluding telecommunication companies ("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 $2,259 ($1,534 after-tax) during Fiscal 2018; $1,461 ($855 after-tax) during Fiscal 2017; and $1,924 ($1,126 after-tax) during Fiscal 2016.

As of September 30, 2018, there was $1,306 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, 2018, there was a total of $1,074 of unrecognized compensation expense associated with 52,441 UGI Unit awards that is expected to be recognized over a weighted average period of 1.8 years. At September 30, 2018 and 2017, total liabilities of $1,200 and $533, 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 2018:

	UGI Units	Weighted-Average Grant-Date Fair Value (per Unit)
Total UGI Units at September 30, 2017 (a)	52,224	$ 40.72
Granted	17,050	$ 53.90
Performance criteria not met	(4,456)	$ 38.69
UGI Unit awards paid	(12,377)	$ 38.54
Total UGI Units at September 30, 2018 (a)	52,441	$ 45.69

(a) Total UGI Units includes UGI Performance Units and UGI Stock Units issued to retirement-eligible employees that vest on an accelerated basis. Total vested restricted units at September 30, 2018 and September 30, 2017 were 9,056 and 6,636, respectively.

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 $6,702 in Fiscal 2018, $7,276 in Fiscal 2017 and $7,669 in Fiscal 2016.

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: 2019— $2,215; 2020 — $1,146; 2021 — $797; 2022 — $739; 2023 — $409; after 2023 — $54.

Contingencies

Environmental Matters

From the late 1800s through the mid-1900s, UGI Utilities and its current and former subsidiaries owned and operated a number of MGPs prior to the general availability of natural gas. Some constituents of coal tars and other residues of the manufactured gas process are today considered hazardous substances under the Superfund Law and may be present on the sites of former MGPs. Between 1882 and 1953, UGI Utilities owned the stock of subsidiary gas companies in Pennsylvania and elsewhere and also operated the businesses of some gas companies under agreement. By the early 1950s, UGI Utilities divested all of its utility operations other than certain Pennsylvania operations, including those now constituting UGI Gas and Electric Utility. Beginning in 2006 and 2008, UGI Utilities also owned and operated two acquired subsidiaries (CPG and PNG) with similar histories of owning, and in some cases operating, MGPs in Pennsylvania. CPG and PNG were merged into UGI Utilities effective October 1, 2018 (“Utilities Merger”).

Prior to the Utilities Merger, each of UGI Utilities and its subsidiaries, CPG and PNG, were subject to a consent order and agreement (“COA”) with the PADEP to address the remediation of specified former MGP sites in Pennsylvania. In accordance with the COAs, as amended to recognize the merger, UGI Utilities, as the successor to CPG and PNG, is required to either obtain a certain number of points per calendar year based on defined eligible environmental investigatory and/or remedial activities at the MGPs and in the case of one COA, an additional obligation to plug specific natural gas wells, or make expenditures for such activities in an amount equal to an annual environmental cost cap. The cost cap of the three COAs, in the aggregate, is $5,350. The three COAs are scheduled to terminate at the end of 2031, 2020, and 2020. At September 30, 2018 and 2017, our aggregate estimated accrued liabilities for environmental investigation and remediation costs related to the COAs totaled $50,970 and $54,250, respectively. UGI Utilities has recorded associated regulatory assets for these costs because recovery of these costs from customers is probable. (See Note 4).

UGI Utilities does not expect the costs for investigation and remediation of hazardous substances at Pennsylvania MGP sites to be material to its results of operations because UGI Utilities receives ratemaking recovery of actual environmental investigation and remediation costs associated with the sites covered by the COAs. This ratemaking recognition reconciles the accumulated difference between historical costs and rate recoveries with an estimate of future costs associated with the sites.

From time to time, UGI Utilities is notified of sites outside Pennsylvania on which private parties allege MGPs were formerly owned or operated by UGI Utilities or owned or operated by a former subsidiary. Such parties generally investigate the extent of environmental contamination or perform environmental remediation. Management believes that under applicable law, UGI Utilities should not be liable in those instances in which a former subsidiary owned or operated an MGP. There could be, however, significant future costs of an uncertain amount associated with environmental damage caused by MGPs outside Pennsylvania that UGI Utilities directly operated, or that were owned or operated by a former subsidiary of UGI Utilities if a court were to conclude that (1) the subsidiary's separate corporate form should be disregarded, or (2) UGI Utilities should be considered to have been an operator because of its conduct with respect to its subsidiary's MGP. At September 30, 2018 and 2017, neither the undiscounted nor the accrued liability for environmental investigation and cleanup costs for UGI Utilities' MGP sites outside Pennsylvania was material.

Other Matters

Manor Township, Pennsylvania Natural Gas Explosion. On July 2, 2017, an explosion occurred in Manor Township, Pennsylvania which resulted in the death of one Company employee and injuries to two other Company employees and an employee of the local sewer authority, and significant property damage. The National Transportation Safety Board ("NTSB") and the BIE are investigating the Manor Township incident. The NTSB investigative team includes representatives from the Company, the BIE, the local fire department and the Pipeline and Hazardous Materials Safety Administration and the Company is cooperating with the investigation. The Company continues to provide information requested by the investigating parties. The Occupational Safety and Health Administration has closed its investigation with no findings. The BIE filed a formal complaint at the PAPUC in which the BIE alleges that the Company committed multiple violations of federal and state gas pipeline regulations in connection with its emergency response leading up to the explosion and requested that the PAPUC order the Company to pay approximately $2,100 in civil penalties, which is the maximum allowable fine. On November 16, 2018, the Company filed its formal written answer contesting the BIE complaint.

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

In addition to the matters described above, there are other pending claims and legal actions arising in the normal course of our businesses. Although we cannot predict the final results of these pending claims and legal actions, we believe, after consultation with counsel, that the final outcome of these matters will not have a material effect on our consolidated financial statements.

13. FAIR VALUE MEASUREMENTS

Derivative Instruments

The following table presents, on a gross basis, our derivative assets and liabilities including both current and noncurrent portions, that are measured at fair value on a recurring basis within the fair value hierarchy as described in Note 2, as of September 30, 2018 and 2017:

	Asset (Liability)			
	Level 1	Level 2	Level 3	Total
September 30, 2018				
Derivative instruments:				
Assets:				
Commodity contracts	$ 3,154	$ —	$ —	$ 3,154
Interest rate contracts	$ —	$ 30	$ —	$ 30
Liabilities:				
Commodity contracts	$ (146)	$ —	$ —	$ (146)
September 30, 2017				
Derivative instruments:				
Assets:				
Commodity contracts	$ 1,735	$ 72	$ —	$ 1,807
Liabilities:				
Commodity contracts	$ (1,447)	$ (73)	$ —	$ (1,520)

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

Other Financial Instruments

The carrying amounts of other financial instruments included in current assets and current liabilities (except for current maturities of long-term debt) approximate their fair values because of their short-term nature. We estimate the fair value of long-term debt by using current market rates and by discounting future cash flows using rates available for similar types of debt (Level 2). The carrying amount and estimated fair value of our long-term debt (including current maturities but excluding unamortized debt issuance costs) at September 30, 2018 and 2017, were as follows:

	2018	2017
Carrying amount	$ 842,130	$ 755,000
Estimated fair value	$ 826,470	$ 791,378

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 PAPUC 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, 2018 and 2017, the volumes of natural gas associated with Gas Utility's unsettled NYMEX natural gas futures and option contracts totaled 23.2 million dekatherms and 14.8 million dekatherms, respectively. At September 30, 2018, the maximum period over which Gas Utility is economically hedging natural gas market price risk is 13 months. Gains and losses on natural gas futures contracts and 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. At September 30, 2018 and 2017, all Electric Utility forward electricity purchase contracts were subject to the NPNS exception.

In order to reduce operating expense volatility, UGI Utilities from time to time enters into NYMEX gasoline futures contracts for a portion of gasoline volumes expected to be used in the operation of its vehicles and equipment. At September 30, 2018 and 2017, the total volumes associated with gasoline futures contracts were not material.

Interest Rate Risk

As previously mentioned in Note 7, in October 2017, UGI Utilities entered into the $125,000 variable-rate Term Loan. Under the Term Loan, UGI Utilities may borrow at various prevailing market interest rates, including LIBOR and the banks' prime rate, plus a margin. In July 2018, UGI Utilities entered into a forward starting, amortizing, pay-fixed, receive-variable interest rate swap that generally fixes the underlying prevailing market interest rates on Term Loan borrowings at 3.00% beginning September 30, 2019 through July 2022.We have designated this forward-starting interest rate swap as a cash flow hedge. The initial notional amount of Term Loan debt subject to this interest rate swap agreement is $114,063.

Our long-term debt typically is issued at fixed rates of interest. As these long-term debt issues mature, we typically refinance such debt with new debt having interest rates reflecting then-current market conditions. In order to reduce market rate risk on the underlying benchmark rate of interest associated with near- to medium-term forecasted issuances of fixed-rate debt, from time to time we enter into interest rate protection agreements ("IRPAs"). We account for IRPAs as cash flow hedges. On March 31, 2016, concurrent with the pricing of UGI Utilities' Senior Notes to be issued under the 2016 Note Purchase Agreement, UGI Utilities settled all of its then-existing IRPA contracts associated with such debt at a loss of $35,975. Because these IRPA contracts qualified for and were designated as cash flow hedges, the loss recognized in connection with the settled IRPAs was recorded in AOCI and is being recognized in interest expense as the associated future interest expense impacts earnings. At September 30, 2018 and 2017, we had no unsettled IRPAs.

At September 30, 2018, the amount of net losses associated with IRPAs expected to be reclassified into earnings during the next twelve months is $3,485.

Derivative Instrument Credit Risk

Our commodity exchange-traded futures contracts generally require cash deposits in margin accounts. At September 30, 2018 and 2017, restricted cash in brokerage accounts totaled $1,190 and $3,046, respectively.

Offsetting Derivative Assets and Liabilities

Derivative assets and liabilities are presented net by counterparty on the Consolidated Balance Sheets if the right of offset exists. Our derivative instruments include both those that are executed on an exchange through brokers and centrally cleared and over-the-counter transactions. Exchange contracts utilize a financial intermediary, exchange or clearinghouse to enter, execute or clear the transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Certain over-the-counter and exchange contracts contain contractual rights of offset through master netting arrangements, derivative clearing agreements and contract default provisions. In addition, the contracts are subject to conditional rights of offset through counterparty nonperformance, insolvency or other conditions.

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

Fair Value of Derivative Instruments

The following table presents the Company’s derivative assets and liabilities, as well as the effects of offsetting, as of September 30, 2018 and 2017:

	2018	2017
Derivative assets:		
Derivatives designated as hedging instruments:		
Interest rate contracts	$ 30	$ —
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	3,002	1,665
Derivatives not designated as hedging instruments:		
Commodity contracts	152	142
Total derivative assets – gross	3,184	1,807
Gross amounts offset in the balance sheet	(146)	(450)
Total derivative assets – net (a)	$ 3,038	$ 1,357
Derivative liabilities:		
Derivatives subject to PGC and DS mechanisms:		
Commodity contracts	$ (146)	$ (1,520)
Total derivative liabilities – gross	(146)	(1,520)
Gross amounts offset in the balance sheet	146	450
Total derivative liabilities – net (a)	$ —	$ (1,070)

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

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 2018, Fiscal 2017 and Fiscal 2016:

	Gain (loss) Recognized in AOCI			Loss Reclassified from AOCI into Income			Location of
	2018	2017	2016	2018	2017	2016	Loss Reclassified from AOCI into Income
Cash Flow Hedges:							
Interest rate contracts	$ 30	$ —	$ (28,958)	$ (3,485)	$ (3,397)	$ (2,680)	Interest expense

	Gain (Loss) Recognized in Income			Location of Gain (Loss)
	2018	2017	2016	Recognized in Income
Derivatives Not Subject to PGC and DS Mechanisms:				
Gasoline contracts	$ 319	$ 174	$ (88)	Operating and administrative expenses/other operating 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 electricity, and service contracts that require the counterparty to provide commodity storage, transportation or capacity service to meet our normal sales commitments. Although many of these contracts have the requisite elements of a derivative instrument, these contracts qualify for NPNS exception accounting because they provide for the delivery of products or services in quantities that are expected to be used in the normal course of operating our business and the price in the contract is based on an underlying that is directly associated with the price of the product or service being purchased or sold.

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, net of tax, during Fiscal 2018, Fiscal 2017 and Fiscal 2016 are as follows:

	Postretirement Benefit Plans	Derivative Instruments	Total
AOCI - September 30, 2015	$ (9,276)	$ (4,410)	$ (13,686)
Reclassifications of benefit plans actuarial losses and net prior service benefits	639	—	639
Reclassifications of net losses on IRPAs	—	1,568	1,568
Net losses on IRPAs	—	(16,942)	(16,942)
Benefit plans, principally actuarial losses	(3,197)	—	(3,197)
AOCI - September 30, 2016	$ (11,834)	$ (19,784)	$ (31,618)
Reclassifications of benefit plans actuarial losses and net prior service benefits	956	—	956
Reclassifications of net losses on IRPAs	—	1,988	1,988
Benefit plans, principally actuarial gains	1,883	—	1,883
AOCI - September 30, 2017	$ (8,995)	$ (17,796)	$ (26,791)
Reclassifications of benefit plans actuarial losses and net prior service benefits	872	—	872
Reclassifications of net losses on IRPAs	—	2,367	2,367
Net gains on interest rate swaps	—	20	20
Benefit plans, principally actuarial gains	3,203	—	3,203
AOCI - September 30, 2018	$ (4,920)	$ (15,409)	$ (20,329)

Reclassifications of net losses on IRPAs 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 and central Pennsylvania. Electric Utility derives its revenues principally from the sale and distribution of electricity in two northeastern Pennsylvania counties.

The accounting policies of our reportable segments are the same as those described in Note 2. Our Chief Operating Decision Maker evaluates 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
2018			
Revenues	$ 1,092,381	$ 994,814	$ 97,567
Cost of sales	$ 522,911	$ 467,528	$ 55,383
Depreciation	$ 84,644	$ 79,124	$ 5,520
Operating income	$ 237,522	$ 230,430	$ 7,092
Interest expense	$ 42,890	$ 41,414	$ 1,476
Income before income taxes	$ 194,632	$ 189,016	$ 5,616
Total assets	$ 3,266,576	$ 3,075,992	$ 190,584
Goodwill	$ 182,145	$ 182,145	$ —
Capital expenditures (including the effects of accruals)	$ 338,548	$ 320,018	$ 18,530
2017			
Revenues	$ 887,588	$ 799,054	$ 88,534
Cost of sales	$ 367,279	$ 318,210	$ 49,069
Depreciation	$ 72,332	$ 67,357	$ 4,975
Operating income	$ 228,307	$ 219,561	$ 8,746
Interest expense	$ 40,212	$ 38,218	$ 1,994
Income before income taxes	$ 188,095	$ 181,343	$ 6,752
Total assets	$ 2,994,015	$ 2,833,423	$ 160,592
Goodwill	$ 182,145	$ 182,145	$ —
Capital expenditures (including the effects of accruals)	$ 317,722	$ 306,243	$ 11,479
2016			
Revenues	$ 768,484	$ 677,387	$ 91,097
Cost of sales	$ 289,786	$ 239,163	$ 50,623
Depreciation	$ 67,303	$ 62,451	$ 4,852
Operating income	$ 200,901	$ 189,412	$ 11,489
Interest expense	$ 37,630	$ 35,786	$ 1,844
Income before income taxes	$ 163,271	$ 153,626	$ 9,645
Total assets	$ 2,743,091	$ 2,570,297	$ 172,794
Goodwill	$ 182,145	$ 182,145	$ —
Capital expenditures (including the effects of accruals)	$ 262,503	$ 251,261	$ 11,242

17. OTHER OPERATING INCOME (EXPENSE), NET

Other operating income (expense), net, comprises the following:

	2018	2017	2016
Non-tariff service income	$ 2,830	$ 1,491	$ 2,633
Environmental matters	—	6,155	(2,918)
Net interest on PGC overcollections	(1,403)	(130)	(1,740)
Other, net	837	813	25
Total other operating income (expense), net	$ 2,264	$ 8,329	$ (2,000)

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 PAPUC in past rate case proceedings and management audits as a reasonable method of allocating such expenses. UGI Utilities also engages in other services with various other affiliates pursuant to arrangements authorized by the PAPUC using similar allocation or market-based pricing methods. 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 PAPUC affiliated interest agreements. Amounts billed to these entities by UGI Utilities during Fiscal 2018, Fiscal 2017 and Fiscal 2016 totaled $5,305, $4,346 and $5,069, respectively.

UGI Utilities is a party to SCAAs with Energy Services which have terms of up to three years. At September 30, 2018, UGI Utilities was a party to four SCAAs with Energy Services, 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, released certain storage and transportation contracts (subject to recall for operational purposes) to Energy Services for the terms of the SCAAs. UGI Utilities also transferred certain associated storage inventories upon the commencement of the SCAAs, receives a transfer of storage inventories at the end of the SCAAs, and makes payments associated with refilling storage inventories during the term of the SCAAs. UGI Utilities incurred costs associated with Energy Services' SCAAs during Fiscal 2018, Fiscal 2017 and Fiscal 2016 totaling $19,854, $21,424 and $12,739, respectively. Energy Services, in turn, provides a firm delivery service and makes certain payments to UGI Utilities for its various obligations under the SCAAs. During Fiscal 2018, Fiscal 2017 and Fiscal 2016, these payments totaled $2,824, $2,747 and $2,002, respectively. In conjunction with the SCAAs, UGI Utilities received security deposits from Energy Services. At September 30, 2018 and 2017, the amounts of such security deposits, which are included in "Other current liabilities" on the Consolidated Balance Sheets, were $11,040.

UGI Utilities reflects the historical cost of the gas storage inventories and any exchange receivable from Energy Services (representing amounts of natural gas inventories used but not yet replenished by Energy Services) on its balance sheet under the caption "Inventories." At September 30, 2018 and 2017, the carrying values of these gas storage inventories, comprising approximately 6.7 bcf and 6.8 bcf of natural gas, were $17,701 and $19,323, 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 2018, Fiscal 2017 and Fiscal 2016 totaled $93,577, $76,010 and $63,331, respectively.

From time to time, UGI Utilities sells natural gas or pipeline capacity to Energy Services. During Fiscal 2018, Fiscal 2017 and Fiscal 2016, revenues associated with such sales to Energy Services totaled $103,667, $50,948 and $30,743, respectively. Also from time to time, UGI Utilities purchases natural gas, pipeline capacity and electricity from Energy Services (in addition to those transactions already described above) and purchases a firm storage service from UGI Storage Company, a subsidiary of Energy Services, under one-year agreements. During Fiscal 2018, Fiscal 2017 and Fiscal 2016, such purchases totaled $156,794, $84,402 and $35,067, respectively.

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,	
	2017	2016	2018	2017	2018	2017	2018	2017
Revenues	$ 323,105	$ 261,413	$ 483,261	$ 359,940	$ 159,934	$ 146,692	$ 126,081	$ 119,543
Operating income	$ 96,295	$ 82,236	$ 135,127	$ 116,408	$ 3,914	$ 27,671	$ 2,186	$ 1,992
Net income (loss)	$ 68,303	$ 44,265	$ 89,184	$ 65,125	$ (3,023)	$ 10,697	$ (5,543)	$ (4,046)

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, 2018				
Reserves deducted from assets in the consolidated balance sheet:				
Allowance for doubtful accounts	$ 4,052	$ 17,970	$ (12,262) [1]	$ 9,760
September 30, 2017				
Reserves deducted from assets in the consolidated balance sheet:				
Allowance for doubtful accounts	$ 3,946	$ 8,030	$ (7,924) [1]	$ 4,052
September 30, 2016				
Reserves deducted from assets in the consolidated balance sheet:				
Allowance for doubtful accounts	$ 5,599	$ 7,760	$ (9,413) [1]	$ 3,946

(1) Uncollectible accounts written off, net of recoveries

EXHIBIT 23

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 20, 2018, 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, 2018.

/s/ Ernst & Young LLP
Philadelphia, Pennsylvania
November 20, 2018

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 20, 2018

/s/ Robert F. Beard

Robert F. Beard
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Daniel J. Platt, certify that:

1. I have reviewed this 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 20, 2018

/s/ Daniel J. Platt

Daniel J. Platt
Vice President - Finance and Chief Financial Officer

EXHIBIT 32

Certification by the Chief Executive Officer and Chief Financial Officer

Relating to a Periodic Report Containing Financial Statements

I, Robert F. Beard, Chief Executive Officer, and I, Daniel J. Platt, Chief Financial Officer, of UGI Utilities, Inc., a Pennsylvania corporation (the "Company"), hereby certify that to our knowledge:

(1) The Company's annual report on Form 10-K for the period ended September 30, 2018 (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	CHIEF FINANCIAL OFFICER
/s/ Robert F. Beard	/s/ Daniel J. Platt
Robert F. Beard	Daniel J. Platt
Date: November 20, 2018	Date: November 20, 2018