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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended: December 31, 2018

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

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

State of Delaware	**51-0064146**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including zip code)

302-734-6799
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock—par value per share $0.4867	New York Stock Exchange, Inc.

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 every Interactive Data File required to be submitted 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	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2018, the last business day of its most recently completed second fiscal quarter, based on the last sale price on that date, as reported by the New York Stock Exchange, was approximately $1.3 billion.

The number of shares of Chesapeake Utilities Corporation's common stock outstanding as of February 15, 2019 was 16,378,821.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2019 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III, which Proxy Statement shall be filed with the Securities and Exchange Commission within 120 days after the end of registrant's fiscal year ended December 31, 2018.

CHESAPEAKE UTILITIES CORPORATION

FORM 10-K

YEAR ENDED DECEMBER 31, 2018

TABLE OF CONTENTS

GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

CDD: Cooling Degree-Day

Chesapeake or Chesapeake Utilities: Chesapeake Utilities Corporation, its divisions and subsidiaries, as appropriate in the context of the disclosure

CHP: Combined Heat and Power Plant

Company: Chesapeake Utilities Corporation, its divisions and subsidiaries, as appropriate in the context of the disclosure

Degree-day: A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am) falls above or below 65 degrees Fahrenheit

Delmarva Peninsula: A peninsula on the east coast of the U. S. occupied by Delaware and portions of Maryland and Virginia

Dt(s): Dekatherm(s), which is a natural gas unit of measurement that includes a standard measure for heating value

Dts/d: Dekatherms per day

Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned subsidiary of Chesapeake Utilities

Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake's OnSight Services, LLC

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

FGT: Florida Gas Transmission Company

Flo-gas: Flo-gas Corporation, a wholly-owned subsidiary of Chesapeake Utilities

FPL: Florida Power & Light Company, an unaffiliated electric company that supplies electricity to FPU

FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake Utilities

GAAP: Generally Accepted Accounting Principles

GRIP: Gas Reliability Infrastructure Program

Gross Margin: a non-GAAP measure defined as operating revenues less the cost of sales. The Company's cost of sales includes purchased fuel cost for natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities and excludes depreciation, amortization and accretion

Gulfstream: Gulfstream Natural Gas System, LLC, an unaffiliated pipeline network that supplies natural gas to FPU

HDD: Heating Degree Day

MetLife: MetLife Investment Advisors, an institutional debt investment management firm, with which Chesapeake Utilities has entered into a Shelf Agreement

MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use

MTM: Mark-to-Market (fair value accounting)

MW: Megawatt, which is a unit of measurement for electric base load power or capacity

NYL: New York Life Investors LLC, an institutional debt investment management firm, with which Chesapeake Utilities has entered into a Shelf Agreement and issued Shelf Notes

Peninsula Pipeline: Peninsula Pipeline Company, Inc., a wholly-owned subsidiary of Chesapeake Utilities

PESCO: Peninsula Energy Services Company, Inc., a wholly-owned subsidiary of Chesapeake Utilities

Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which Chesapeake Utilities has entered into a Shelf Agreement and issued Shelf Notes

PSC: Public Service Commission, which is the state agency that regulates utility rates and/or services in certain of our jurisdictions

Rayonier: Rayonier Performance Fibers, LLC, the company that owns the property on which Eight Flags' CHP plant is located and a customer of the steam generated by the CHP plant

Revolver: Our unsecured revolving credit facility with certain lenders

Sandpiper: Sandpiper Energy, Inc., a wholly-owned subsidiary of Chesapeake Utilities

SEC: Securities and Exchange Commission

Senior Notes: Our unsecured long-term debt issued primarily to insurance companies on various dates

Sharp: Sharp Energy, Inc., a wholly-owned subsidiary of Chesapeake Utilities

Shelf Agreement: An agreement entered into by Chesapeake Utilities and a counterparty pursuant to which Chesapeake Utilities may request that the counterparty purchase our unsecured senior debt with a fixed interest rate and a maturity date not to exceed 20 years from the date of issuance

Shelf Notes: Unsecured senior promissory notes issuable under the Shelf Agreement executed with various counterparties

SICP: 2013 Stock and Incentive Compensation Plan

TCJA: Tax Cuts and Jobs Act enacted on December 22, 2017

TETLP: Texas Eastern Transmission, LP

U.S.: The United States of America

Xeron: Xeron, Inc., an inactive subsidiary of Chesapeake Utilities

PART I

References in this document to “Chesapeake,” “Chesapeake Utilities,” the “Company,” “we,” “us” and “our” mean Chesapeake Utilities Corporation, its divisions and/or its wholly-owned subsidiaries, as appropriate in the context of the disclosure.

Safe Harbor for Forward-Looking Statements

We make statements in this Annual Report on Form 10-K that do not directly or exclusively relate to historical facts. Such statements are “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as “project,” “believe,” “expect,” “anticipate,” “intend,” “plan,” “estimate,” “continue,” “potential,” “forecast” or other similar words, or future or conditional verbs such as “may,” “will,” “should,” “would” or “could.” These statements represent our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. Forward-looking statements speak only as of the date they are made or as of the date indicated and we do not undertake any obligation to update forward-looking statements as a result of new information, future events or otherwise. These statements are subject to many risks and uncertainties. In addition to the risk factors described under *Item 1A, Risk Factors*, the following important factors, among others, could cause actual future results to differ materially from those expressed in the forward-looking statements:

- state and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed and the degree to which competition enters the electric and natural gas industries;
- the outcomes of regulatory, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the related costs are adequately covered by insurance or recoverable in rates;
- the impact of significant changes to current tax regulations and rates;
- the timing of certification authorizations associated with new capital projects and the ability to construct facilities at or below estimated costs;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now, or may in the future, own or operate;
- possible increased federal, state and local regulation of the safety of our operations;
- the economy in our service territories or markets, the nation, and worldwide, including the impact of economic conditions (which we do not control) on demand for electricity, natural gas, propane or other fuels;
- risks related to cyber-attacks or cyber-terrorism that could disrupt our business operations or result in failure of information technology systems;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- customers' preferred energy sources;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the effect of competition on our businesses;
- the timing and extent of changes in commodity prices and interest rates;
- the effect of spot, forward and future market prices on our various energy businesses;
- the extent of our success in connecting natural gas and electric supplies to transmission systems, establishing and maintaining key supply sources; and expanding natural gas and electric markets;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the capital-intensive nature of our regulated energy businesses;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the ability to successfully execute, manage and integrate a merger, acquisition or divestiture of assets or businesses and the related regulatory or other conditions associated with the merger, acquisition or divestiture;
- the impact on our costs and funding obligations, under our pension and other post-retirement benefit plans, of potential downturns in the financial markets, lower discount rates, and costs associated with health care legislation and regulation;
- the ability to continue to hire, train and retain appropriately qualified personnel; and
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies.

ITEM 1. Business.

Corporate Overview and Strategy

Chesapeake Utilities Corporation is a Delaware corporation formed in 1947 with operations primarily in the Mid-Atlantic region and in Florida, Pennsylvania and Ohio. We are an energy delivery company engaged in the distribution of natural gas, propane and electricity; the transmission of natural gas; the generation of electricity and steam, and in providing related services to our customers.

Our strategy is to consistently produce industry leading total shareholder return by profitably investing capital into opportunities that leverage our skills and expertise in energy distribution and transmission to achieve high levels of service and growth. The key elements of our strategy include:

- capital investment in growth opportunities that generate our target returns;
- expanding our energy distribution and transmission operations within our existing service areas as well as into new geographic areas;
- providing new services in our current service areas;
- expanding our footprint in potential growth markets through strategic acquisitions;
- entering new energy markets and businesses that complement our existing operations and growth strategy; and
- operating as a customer-centric full-service energy supplier/partner/provider, while providing safe and reliable service.

Our employees strive to build meaningful connections that generate opportunities to grow our businesses, develop new markets, and enrich the communities in which we live, work and serve.

Operating Segments

We operate within two reportable segments: Regulated Energy and Unregulated Energy. The remainder of our operations is presented as “Other businesses and eliminations." These segments are described below in detail.

Regulated Energy

Our regulated energy businesses are comprised of natural gas and electric distribution as well as natural gas transmission services. The following table presents net income for the year ended December 31, 2018 and total assets as of December 31, 2018, for the Regulated Energy segment by operation and area served:

Operations	Areas Served	Net Income	Total Assets
(in thousands)			
Natural Gas Distribution			
Delmarva Natural Gas (Delaware division, Maryland division and Sandpiper Energy)	Delaware/Maryland	$ 11,390	$ 211,458
Central Florida Gas and FPU	Florida	11,754	312,769
Natural Gas Transmission			
Eastern Shore	Delaware/Maryland/ Pennsylvania	17,460	262,918
Peninsula Pipeline	Florida	4,303	20,493
Electric Distribution			
FPU	Florida	2,249	123,863
Total Regulated Energy		$ 47,156	$ 931,501

Revenues in this operating segment are based on rates regulated by the PSC in the states in which we operate or, in the case of Eastern Shore, which is an interstate business, by the FERC. The rates are designed to generate revenues to recover all prudent operating and financing costs and provide a reasonable return for our stockholders. Each of our distribution and transmission operations has a rate base, which generally consists of the original cost of the operation's plant, less accumulated depreciation, working capital and other assets. For Delmarva Natural Gas and Eastern Shore, rate base also includes deferred income tax liabilities and other additions or deductions. Our Regulated Energy operations in Florida do not include deferred income tax liabilities in their rate base.

Our natural gas and electric distribution operations bill customers at standard rates approved by their respective state PSC. Each state PSC allows us to negotiate rates, based on approved methodologies, for large customers that can switch to other fuels. Some of our customers in Maryland receive propane through our underground distribution system in Worcester County, which we are in the process of converting to natural gas. We bill these customers under PSC-approved rates and include them in the natural gas distribution results and customer statistics.

Our natural gas and electric distribution operations earn profits on the delivery of natural gas or electricity to customers. The cost of natural gas or electricity that we deliver is passed through to customers under PSC-approved fuel cost recovery mechanisms. The mechanisms allow us to adjust our rates on an ongoing basis without filing a rate case to recover changes in the cost of the natural gas and electricity that we purchase for customers. Therefore, while our distribution operating revenues fluctuate with the cost of natural gas or electricity we purchase, our distribution margin (which we define as operating revenues less purchased gas or electric cost) is generally not impacted by fluctuations in the cost of natural gas or electricity.

Our natural gas transmission operations bill customers under rate schedules approved by the FERC or at rates negotiated with customers.

Operational Highlights

The following table presents operating revenues, volumes and the average number of customers by customer class for our natural gas and electric distribution operations for the year ended December 31, 2018:

	Delmarva Natural Gas Distribution		Florida Natural Gas Distribution [2]		FPU Electric Distribution	
Operating Revenues *(in thousands)*						
Residential	$ 70,466	60%	$ 35,420	34%	$ 44,788	56 %
Commercial	36,916	32%	33,229	31%	39,442	49 %
Industrial	8,289	7%	33,207	31%	1,543	2 %
Other [1]	928	1%	4,602	4%	(5,970)	(7)%
Total Operating Revenues	$ 116,599	100%	$ 106,458	100%	$ 79,803	100 %
Volumes *(in Dts for natural gas/KW Hours for electric)*						
Residential	4,142,567	31%	1,762,852	5%	307,269	49 %
Commercial	3,792,220	28%	6,441,806	18%	302,687	48 %
Industrial	5,549,387	40%	24,759,334	70%	15,160	2 %
Other	80,254	1%	2,338,815	7%	7,402	1 %
Total Volumes	13,564,428	100%	35,302,807	100%	632,518	100 %
Average Number of Customers [3]						
Residential	71,322	91%	72,151	90%	24,686	77 %
Commercial	6,979	9%	5,434	7%	7,497	23 %
Industrial	157	<1%	2,328	3%	2	<1%
Other	5	<1%	11	<1%	—	— %
Total Average Number of Customers	78,463	100%	79,924	100%	32,185	100 %

[1] Operating Revenues from "Other" sources include revenue, unbilled revenue, under (over) recoveries of fuel cost, conservation revenue, other miscellaneous charges, fees for billing services provided to third parties, and adjustments for pass-through taxes.
[2] Florida natural gas distribution includes Chesapeake Utilities' Central Florida Gas division, FPU and FPU's Indiantown and Fort Meade divisions.
[3] Average number of customers is based on the twelve-month average for the year ended December 31, 2018.

The following table presents operating revenues, by customer type, for Eastern Shore and Peninsula Pipeline for the year ended December 31, 2018, and contracted firm transportation capacity, by customer type, as well as design day capacity at December 31, 2018:

	Eastern Shore		Peninsula Pipeline	
Operating Revenues *(in thousands)*				
Local distribution companies - affiliated [1]	$ 19,725	31 %	$ 9,478	80%
Local distribution companies - non-affiliated	23,975	37 %	840	7%
Commercial and industrial - affiliated	—	— %	1,120	9%
Commercial and industrial - non-affiliated	21,748	34 %	490	4%
Other [2]	(1,200)	(2)%	—	—%
Total Operating Revenues	$ 64,248	100 %	$ 11,928	100%
Contracted firm transportation capacity *(in Dts/d)*				
Local distribution companies - affiliated	122,652	42 %	143,500	93%
Local distribution companies - non-affiliated	76,619	26 %	4,825	3%
Commercial and industrial - affiliated	—	— %	1,500	1%
Commercial and industrial - non-affiliated	95,648	32 %	5,100	3%
Total Contracted firm transportation capacity	294,919	100 %	154,925	100%
Design day capacity *(in Dts/d)*	294,919	100 %	154,925	100%

(1) Eastern Shore's and Peninsula Pipeline's service to our local distribution affiliates is based on the respective regulator's approved rates and is an integral component of the cost associated with providing natural gas supplies for those affiliates. We eliminate operating revenues of these entities against the cost of sales of those affiliates in our consolidated financial information; however, our local distribution affiliates include this amount in their purchased fuel cost and recover it through fuel cost recovery mechanisms.

(2) Operating revenues from "Other" sources are from the rental of gas properties and reserve for rate case refund.

Regulatory Overview

The following table highlights key regulatory information for each of our principal Regulated Energy operations. The table reflects rate increases and rates of return approved prior to the enactment of the TCJA on December 22, 2017. See *Item 8, Financial Statements and Supplementary Data* (Note 19, *Rates and Other Regulatory Activities* and Note 12, *Income Taxes* in the consolidated financial statements) for further discussion on the impact of this legislation on our regulated businesses. Peninsula Pipeline is not regulated with regard to cost of service by either the Florida PSC or FERC and is therefore excluded from the table.

	Natural Gas Distribution						
	Delmarva			**Florida**		**Electric Distribution**	**Natural Gas Transmission**
Operation/Division	**Delaware**	**Maryland**	**Sandpiper**	**Chesapeake's Florida natural gas division**	**FPU**	**FPU**	**Eastern Shore**
Regulatory Agency	Delaware PSC	Maryland PSC	Maryland PSC	Florida PSC	Florida PSC	Florida PSC	FERC
Effective date - Last Rate Order	01/01/2017	5/1/2018[7]	12/01/2018	01/14/2010	01/14/2010[1]	01/03/2018	08/01/2017
Rate Base (in Rates)	Not stated	Not stated	Not stated	$46,680,000	$68,940,000	$11,850,000	Not stated
Annual Rate Increase Approved	$2,250,000	N/A[7]	N/A[2]	$2,540,000	$7,970,000	$1,560,000	$9,800,000
Capital Structure (in rates)[3]*	Not stated	LTD: 42.00% STD: 5.00% Equity: 53.00%	Not stated	LTD: 30.63% STD: 6.26% Equity: 43.49% Other: 19.62%	LTD: 30.75% Equity: 46.67% Other: 22.58%	LTD: 21.91% STD: 23.50% Equity: 54.59%	Not stated
Allowed Return on Equity	9.75% [4]	10.75%[4]	Not Stated [5]	10.80%[4]	10.85%[4]	10.25%[4], [6]	Not Stated
TJCA Refund Status associated with customer rates	Reserved	Refunded	Refunded	Reserved	Reserved	Reserved	Refunded

(1) The effective date of the order approving the settlement agreement, which adjusted the rates originally approved on June 4, 2009.

[2]The Maryland PSC approved a declining return on equity that will result in a decline in our rates.
[3]Other components of capital structure include customer deposits, deferred income taxes and tax credits.
[4] Allowed after-tax return on equity.
[5] The terms of the agreement include revenue neutral rates for the first year (December 1, 2016 through November 30, 2017), followed by a schedule of rate reductions in subsequent years based upon the projected rate of propane to natural gas conversions.
[6] The terms of the settlement agreement for the FPU electric division limited proceeding with the Florida PSC prescribed an authorized return on equity range of 9.25 to 11.25 percent, with a mid-point of 10.25 percent. The FPU electric division cannot file for a base rate increase prior to December 2019, unless its allowed return on equity is below the authorized range and it experiences an unanticipated and unforeseen event that impacts the annual revenue requirement in excess of $800,000 within any contiguous four-month period.
[7] The Maryland PSC approved a rate reduction for Maryland division effective May 1, 2018, related to the enactment of the TJCA.
[*] LTD-Long-term debt; STD-Short-term debt

The following table presents surcharge and other mechanisms that have been approved by the respective PSC for our regulated energy distribution businesses. These include Delaware's surcharge to expand natural gas service in eastern Sussex County; Maryland's surcharge to fund natural gas conversions and system improvement in Worcester County; Florida's GRIP surcharge which provides accelerated recovery of the costs of replacing older portions of the natural gas distribution system to improve safety and reliability and Florida electric distribution operation's limited proceeding.

Operation(s)/Division(s)	Jurisdiction	Infrastructure mechanism	Revenue normalization
Delaware division	Delaware	No	No
Maryland division	Maryland	No	Yes
Sandpiper Energy	Maryland	Yes	Yes
FPU and Central Florida Gas natural gas divisions	Florida	Yes	No
FPU electric division	Florida	Yes	No

Weather

Weather variations directly influence the volume of natural gas and electricity sold and delivered to residential and commercial customers for heating and cooling and changes in volumes delivered impact the revenue generated from these customers. Natural gas volumes are highest during the winter months, when residential and commercial customers use more natural gas for heating. Demand for electricity is highest during the summer months, when more electricity is used for cooling. We measure the relative impact of weather using degree-days. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature falls above or below 65 degrees Fahrenheit. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating degree-day, and each degree of temperature above 65 degrees Fahrenheit is counted as one cooling degree-day. Normal heating and cooling degree-days are based on the most recent 10-year average.

Competition

Natural Gas Distribution

While our natural gas distribution operations do not compete directly with other distributors of natural gas for residential and commercial customers in our service areas, we do compete with other natural gas suppliers and alternative fuel providers for sales to industrial customers. Large customers could bypass our natural gas distribution systems and connect directly to interstate transmission pipelines, and we compete in all aspects of our natural gas business with alternative energy sources, including electricity, oil, propane and renewables. The most effective means to compete against alternative fuels are lower prices, superior reliability and flexibility of service. Natural gas historically has maintained a price advantage in the residential, commercial and industrial markets, and reliability of natural gas supply and service has been excellent. In addition, we provide flexible pricing to our large customers to minimize fuel switching and protect these volumes and their contributions to the profitability of our natural gas distribution operations.

Natural Gas Transmission

Our natural gas transmission business competes with other pipeline companies to provide service to large industrial, generating and distribution customers, primarily in the northern portion of Delmarva and in Florida.

Electric Distribution

While our electric distribution operations do not compete directly with other distributors of electricity for residential and commercial customers in our service areas, we do compete with other electricity suppliers and alternative fuel providers for sales to industrial customers. Some of our large industrial customers may be capable of generating their own electricity, and we structure rates, flexibility and service offerings to retain these customers in order to retain their business and contributions to the profitability of our electric distribution operations.

Supplies, Transmission and Storage

Natural Gas Distribution

Our natural gas distribution operations purchase natural gas from marketers and producers and maintain contracts for transportation and storage with several interstate pipeline companies to meet projected customer demand requirements. We believe that our supply and capacity strategy will adequately meet our customers' needs over the next several years.

The Delmarva natural gas distribution systems are directly connected to Eastern Shore's pipeline, which has connections to the other pipelines that provide us with transportation and storage. These operations can also use propane-air and liquefied natural gas peak-shaving equipment to serve customers. Our Delmarva operations receive a fee, which we share with our customers, from our natural gas marketing subsidiary, PESCO, who optimizes the transportation, storage and natural gas supply for these operations under a three-year contract.

We have a contract with an unaffiliated party to supply propane for customers of our Sandpiper system in Maryland who have not yet converted to natural gas. Under the contract, we are committed to purchase approximately 932,000 gallons of propane annually at either a fixed per-gallon or a local indexed-index-based price. The contract expires in May 2019, at which time, we can purchase the propane from our propane subsidiary or the external markets directly.

Our Florida natural gas distribution operation uses Peninsula Pipeline and the Peoples Gas System division of Tampa Electric Company ("Peoples Gas") to transport natural gas where there is no direct connection with FGT.

A summary of our pipeline capacity contracts follows:

Division	Pipeline	Maximum Daily Firm Transportation Capacity (Dts)	Contract Expiration Date
Delmarva Natural Gas Distribution	Eastern Shore	122,652	2019-2028
	Columbia Gas[1]	15,160	2020-2024
	Transco[1]	27,551	2019-2028
	TETLP[1]	50,000	2027
Florida Natural Gas Distribution	Gulfstream[2]	10,000	2022
	FGT	41,909 - 73,317	2020-2041
	Peninsula Pipeline	137,500	2033-2048
	Peoples Gas	2,660	2024-2035

[1] Transcontinental Gas Pipe Line Company, LLC ("Transco"), Columbia Gas Transmission, LLC ("Columbia Gas") and Texas Eastern Transmission, LP ("TETLP") are interstate pipelines interconnected with Eastern Shore's pipeline

[2] Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under this agreement has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake Utilities is contingently liable to Gulfstream should any party, that acquired the capacity through release, fail to pay the capacity charge.

Eastern Shore has three agreements with Transco for a total of 7,292 Dts/d of firm daily storage injection and withdrawal entitlements and total storage capacity of 288,003 Dts. These agreements expire on various dates between 2019 and 2023. Eastern Shore retains these firm storage services in order to provide swing transportation service and firm storage service to customers requesting such services.

Electric Distribution

Our Florida electric distribution operation purchases wholesale electricity under the power supply contracts summarized below:

Counterparty	Area Served by Contract	Contracted Amount (MW)	Contract Expiration Date
Gulf Power Company	Northwest Florida	Full Requirement*	2019
FPL	Northeast Florida	Full Requirement*	2024
Eight Flags	Northeast Florida	21.0	2036
Rayonier	Northeast Florida	1.7 to 3.0	2036
WestRock Company	Northwest Florida	As-available	N/A

*The counter party is obligated to provide us with the electricity to meet our customers' demand, which may vary.

Unregulated Energy

The following table presents net income for the year ended December 31, 2018 and total assets as of December 31, 2018, for our Unregulated Energy segment by operation and area served:

Operations	Area Served	Net Income	Total Assets
(in thousands)			
Propane Operations (Sharp, FPU and Flo-gas)	Delaware, Maryland, Virginia, Pennsylvania, Florida	$ 6,443	$ 86,989
Energy Transmission (Aspire Energy)	Ohio	3,620	85,733
Energy Generation (Eight Flags)	Florida	1,657	10,895
Energy Services (PESCO)	Appalachian Basin, Mid-Atlantic, Southeast, Western Pennsylvania	(1,288)	55,021
Marlin Gas Services [1]	Southeast and Midwest	(186)	14,046
Other	Other	393	2,884
Total		$ 10,639	$ 255,568

[1] In December 2018, Marlin Gas Services, LLC ("Marlin Gas Services"), our newly created subsidiary, acquired the assets of Marlin Gas Transport, Inc. ("Marlin Gas Transport"). The net loss reported is a result of the costs of consummating the acquisition exceeding the margin generated for approximately half of December 2018.

Propane Operations

Our propane operations sell propane to residential, commercial/industrial, wholesale and AutoGas customers, in the Mid-Atlantic region, through Sharp Energy, Inc. and Sharpgas, Inc., and in Florida through FPU and Flo-gas. We deliver to and bill our propane customers based on two primary customer types: bulk delivery customers and metered customers. Bulk delivery customers receive deliveries into tanks at their location. We invoice and record revenues for these customers at the time of delivery. Metered customers are either part of an underground propane distribution system or have a meter installed on the tank at their location. We invoice and recognize revenue for these customers based on their consumption as dictated by scheduled meter reads. As a member of AutoGas Alliance, we install and support propane vehicle conversion systems for vehicle fleets and provide onsite fueling infrastructure.

Propane Operations - Operational Highlights

For the year ended December 31, 2018, operating revenues, volumes sold and average number of customers by customer class for our Mid-Atlantic and Florida propane operations were as follows:

	Operating Revenues (in thousands)				**Volumes (in thousands of gallons)**				**Average Number of Customers [2]**			
	Mid-Atlantic		**Florida**		**Mid-Atlantic**		**Florida**		**Mid-Atlantic**		**Florida**	
Residential bulk	$ 27,090	26%	$ 6,799	32%	10,483	17%	1,547	23%	25,870	66%	10,312	59%
Residential metered	9,933	10%	5,037	24%	4,157	7%	905	13%	9,123	23%	6,034	34%
Commercial bulk	23,431	23%	5,393	25%	14,360	24%	2,550	38%	4,201	11%	971	6%
Commercial metered	—	—%	2,127	10%	—	—%	820	12%	—	—%	280	1%
Wholesale	31,469	31%	1,165	5%	28,680	47%	944	14%	31	<1%	8	<1%
AutoGas	4,238	4%	—	—%	3,104	5%	—	—%	85	<1%	—	—%
Other [1]	6,160	6%	761	4%	—	—%	—	—%	—	—%	—	—%
Total	$102,321	100%	$ 21,282	100%	60,784	100%	6,766	100%	39,310	100%	17,605	100%

[1] Operating revenues from "Other" sources include revenues from customer loyalty programs; delivery, service and appliance fees; and unbilled revenues.
[2] Average number of customers is based on a twelve-month average for the year ended December 31, 2018.

Competition

Our propane operations compete with national and local independent companies primarily on the basis of price and service. Propane is generally a cheaper fuel for home heating than oil and electricity but more expensive than natural gas. Our propane operations are largely concentrated in areas that are not currently served by natural gas distribution systems.

Supplies, Transportation and Storage

We purchase propane from major oil companies and independent natural gas liquids producers. Propane is transported by truck and rail to our bulk storage facilities in Delaware, Maryland, Florida, Pennsylvania and Virginia, which have a total storage capacity of 7.1 million gallons. Deliveries are made from these facilities by truck to tanks located on customers' premises or to central storage tanks that feed our underground propane distribution systems. While propane supply has traditionally been adequate, significant fluctuations in weather, closing of refineries and disruption in supply chains, could cause temporary reductions in available supplies.

Weather

Propane revenues are affected by seasonal variations in temperature and weather conditions, which directly influence the volume of propane used by our customers. Our propane revenues are typically highest during the winter months when propane is used for heating. Sustained warmer-than-normal temperatures will tend to reduce propane use, while sustained colder-than-normal temperatures will tend to increase consumption.

Unregulated Energy Transmission (Aspire Energy)

Aspire Energy owns approximately 2,700 miles of natural gas pipeline systems in 40 counties in Ohio. The majority of Aspire Energy's revenues are derived from long-term supply agreements with Columbia Gas of Ohio and Consumers Gas Cooperative ("CGC"), which together serve more than 21,000 end-use customers. Aspire Energy purchases natural gas to serve these customers from conventional producers in the Marcellus and Utica natural gas production areas. In addition, Aspire Energy earns revenue by gathering and processing natural gas for customers.

For the twelve-month period ended December 31, 2018, Aspire Energy's operating revenues and deliveries by customer type were as follows:

	Operating revenues		Deliveries	
	(in thousands)	% of Total	*(in thousands Dts)*	% of Total
Supply to Columbia Gas of Ohio	$ 13,429	38%	2,538	38%
Supply to CGC	12,530	35%	1,611	25%
Supply to Marketers - affiliated	2,654	8%	1,013	15%
Supply to Marketers - unaffiliated	3,918	11%	1,328	20%
Other (including natural gas gathering and processing)	2,876	8%	141	2%
Total	$ 35,407	100%	6,631	100%

Energy Generation (Eight Flags)

Eight Flags generates electricity and steam at its CHP plant located on Amelia Island, Florida. The plant is powered by natural gas transported by Peninsula Pipeline and our Florida natural gas distribution operation and produces approximately 21 MW of electricity and 75,000 pounds per hour of steam. Eight Flags sells the electricity generated from the plant to our Florida electric distribution operation and sells the steam to the customer who owns the site on which the plant is located both under separate 20-year contracts.

Energy Services (PESCO)

PESCO competes with utilities and third-party marketers to sell natural gas and related services directly to commercial and industrial customers. PESCO delivers the natural gas it sells to customers through affiliated and non-affiliated natural gas distribution systems and pipelines and bills customers directly or through the billing services of the natural gas distribution utility that delivers the gas to PESCO's customer. PESCO manages a portion of the natural gas transportation and storage capacity for our Delmarva natural gas distribution operations under three-year asset management agreements that expire on March 31, 2020.

The following table summarizes PESCO's operating revenues by region in 2018:

	Operating Revenues	
	(in thousands)	**% of Total**
Appalachian Basin	$ 34,713	13%
Mid-Atlantic	127,148	49%
Southeast	59,077	23%
Western Pennsylvania	37,775	15%
Total	$ 258,713	100%

Marlin Gas Services

In December 2018, Marlin Gas Services, our newly created subsidiary, acquired certain operating assets of Marlin Gas Transport, a supplier of mobile compressed natural gas utility and pipeline solutions. Marlin Gas Services provides a temporary solution for gas pipeline and gas distribution systems while safety and integrity work is being performed. The assets purchased have the capacity to transport more than 7 billion cubic feet of natural gas annually using one of the largest fleets of tube trailers dedicated to the transportation of compressed natural gas ("CNG"). The acquisition will allow us to offer solutions to address supply interruption scenarios and provide other unique applications where pipeline supplies are not available or cannot meet customer requirements. Operating revenues and net income generated from the date of acquisition through the year ended December 31, 2018 were immaterial.

Other Businesses and Eliminations

Other businesses and eliminations consists primarily of subsidiaries that own real estate leased to affiliates, eliminations of inter-segment revenue and corporate costs which are not directly attributable to a specific business unit. See *Item 8, Financial Statements and Supplementary Data* (Note 6, *Segment Information*, in the consolidated financial statements) for more information.

Environmental Matters

See *Item 8, Financial Statements and Supplementary Data* (see Note 20*, Environmental Commitments and Contingencies,* in the consolidated financial statements).

Employees

As of December 31, 2018, we had a total of 983 employees, 119 of whom are union employees represented by two labor unions: the International Brotherhood of Electrical Workers and the United Food and Commercial Workers Union. The collective bargaining agreements with these labor unions expire in 2019.

Executive Officers

Set forth below are the names, ages, and positions of our executive officers with their recent business experience. The age of each officer is as of the filing date of this report.

Name	Age	Officer Since	Offices Held During the Past Five Years
Jeffry M. Householder	61	2010	President (January 1, 2019 - present) Chief Executive Officer (January 1, 2019 - present) Director (January 1, 2019 - present) President of FPU (June 2010 - February 26, 2019)
Beth W. Cooper	52	2005	Executive Vice President (Beginning February 26, 2019) Chief Financial Officer (September 2008 - present) Senior Vice President (September 2008 - February 26, 2019) Assistant Corporate Secretary (March 2015 - present) Corporate Secretary (June 2005 - March 2015)
James F. Moriarty	61	2015	Executive Vice President (Beginning February 26, 2019) General Counsel & Corporate Secretary (March 2015 - present) Chief Policy and Risk Officer (Beginning February 26, 2019) Senior Vice President (February 2017 - February 26, 2019) Vice President (March 2015 - February 2017)
Stephen C. Thompson	58	1997	Senior Vice President (September 2004 - present) President, Eastern Shore (January 1997 - present) President and Chief Operating Officer, Sandpiper (May 2014 - present) Vice President (May 1997 - September 2004)

Available Information on Corporate Governance Documents

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments to these reports that we file with or furnish to the SEC are available free of charge at our website, *www.chpk.com,* as soon as reasonably practicable after we electronically file these reports with, or furnish these reports to the SEC. The content of this website is not part of this report.

In addition, the following documents are available free of charge on our website, *www.chpk.com*:

- Business Code of Ethics and Conduct applicable to all employees, officers and directors;
- Code of Ethics for Financial Officers;
- Corporate Governance Guidelines;
- Charters for the Audit Committee, Compensation Committee, Investment Committee, and Corporate Governance Committee of the Board of Directors; and
- Corporate Governance Guidelines on Director Independence.

Any of these reports or documents may also be obtained by writing to: Corporate Secretary; c/o Chesapeake Utilities Corporation, 909 Silver Lake Boulevard, Dover, DE 19904.

ITEM 1A. RISK FACTORS.

The following is a discussion of the primary factors that may affect the operations and/or financial performance of our regulated and unregulated energy businesses. Refer to the section entitled *Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations* of this report for an additional discussion of these and other related factors that affect our operations and/or financial performance.

FINANCIAL RISKS

Instability and volatility in the financial markets could negatively impact access to capital at competitive rates, which could affect our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth.

Our business strategy includes the continued pursuit of growth and requires capital investment in excess of cash flow from operations. As a result, the successful execution of our strategy is dependent upon access to equity and debt at reasonable costs. Our ability to issue new debt and equity capital and the cost of equity and debt are greatly affected by our financial performance and the conditions of the financial markets. In addition, our ability to obtain adequate and cost-effective debt depends on our credit ratings. A downgrade in our current credit ratings could negatively impact our access to and cost of debt. If we are not able to access capital at competitive rates, our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth may be limited.

PESCO is exposed to market risks beyond our control, which could adversely affect our financial results and capital requirements.

PESCO is subject to market risks beyond our control, including market liquidity and commodity price volatility. Although we maintain a risk management policy, we may not be able to offset completely the price risk associated with volatile commodity prices, which could lead to volatility in earnings. Physical trading also has price risk on any net open positions at the end of each trading day, as well as volatility resulting from (i) intra-day fluctuations of natural gas prices, and (ii) daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is economically hedged. The determination of our net open position at the end of any trading day requires us to make assumptions as to future circumstances, including the use of natural gas by our customers in relation to anticipated market positions. Because the price risk associated with any net open position at the end of such day may increase if the assumptions are not realized, we review these assumptions daily. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner, because the changes in fair value of trading contracts are immediately recognized as profits or losses for financial accounting purposes. This volatility may occur, with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated.

PESCO is exposed to the credit risk of its counterparties.

PESCO extends credit to counterparties and continually monitors and manages collections aggressively. There is risk that PESCO may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform, and any underlying collateral is inadequate, we could experience financial losses, which would negatively impact our results of operations.

PESCO is dependent upon the availability of credit to successfully operate its business.

PESCO depends upon credit to buy natural gas for resale or to trade. If financial market conditions or the financial condition of our Company declines, then the cost of credit could increase or become unavailable, which might adversely affect our results of operations, cash flows and financial condition.

Fluctuations in propane gas prices could negatively affect results of operations.

We adjust the price of the propane we sell based on changes in our cost of purchasing propane. However, if the market does not allow us to increase propane sales prices to compensate fully for fluctuations in purchased gas costs, our results of operations and earnings could be negatively affected.

If we fail to comply with our debt covenant obligations, we could experience adverse financial consequences that could affect our liquidity and ability to borrow funds.

Our long-term debt obligations, term loans, the Revolver and our committed short-term lines of credit contain financial covenants related to debt-to-capital ratios and interest-coverage ratios. Failure to comply with any of these covenants could result in an event of default which, if not cured or waived, could result in the acceleration of outstanding debt obligations or the inability to borrow under certain credit agreements. Any such acceleration could cause a material adverse change in our financial condition.

Increases in interest rates may adversely affect our results of operations and cash flows.

Increases in interest rates could increase the cost of future debt issuances. Absent recovery of the higher debt cost in the rates we charge our utility customers, our earnings could be adversely affected. Increases in short-term interest rates could negatively affect our results of operations, which depend on short-term lines of credit to finance accounts receivable and storage gas inventories and to temporarily finance capital expenditures. Reference should be made to *Item 7A, Quantitative and Qualitative Disclosures about Market Risk* for additional information.

Current market conditions could adversely impact the return on plan assets for our pension plans, which may require significant additional funding.

Our pension plans are closed to new employees, and the future benefits are frozen. The costs of providing benefits and related funding requirements of these plans are subject to changes in the market value of the assets that fund the plans and the discount rates used to estimate the pension benefit obligations. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors that are subject to an inherent degree of uncertainty, particularly in the current economic environment. Future losses of asset values and further declines in discount rates may necessitate accelerated funding of the plans to meet minimum federal government requirements and may result in higher pension expense in future years. Adverse changes in the benefit obligations of our pension plans may require us to record higher pension expense and fund obligations earlier than originally planned, which would have an adverse impact on our cash flows from operations, decrease borrowing capacity and increase interest expense.

OPERATIONAL RISKS

We are dependent upon construction of new facilities to support future growth in earnings in our natural gas and electric distribution and natural gas transmission operations.

Construction of new facilities required to support future growth is subject to various regulatory and developmental risks, including but not limited to: (i) our ability to obtain timely certificate authorizations, necessary approvals and permits from regulatory agencies and on terms that are acceptable to us; (ii) potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project; (iii) our inability to acquire rights-of-way or land rights on a timely basis on terms that are acceptable to us; (iv) lack of anticipated future growth in available natural gas and electricity supply; (v) insufficient customer throughput commitments; and (vi) lack of available and qualified third-party contractors which could impact the timely construction of new facilities.

We operate in a competitive environment, and we may lose customers to competitors.

Natural Gas. Our natural gas transmission and distribution operations compete with interstate pipelines when our customers are located close enough to a competing pipeline to make direct connections economically feasible. Our natural gas marketing operations compete with third-party suppliers to sell natural gas to commercial and industrial customers. Customers also have the option to switch to alternative fuels, including renewable energy sources. Failure to retain and grow our natural gas customer base would have an adverse effect on our financial condition, cash flows and results of operations.

Electric. Our Florida electric distribution business has remained substantially free from direct competition from other electric service providers but does face competition from other energy sources. Changes in the competitive environment caused by legislation, regulation, market conditions, or initiatives of other electric power providers, particularly with respect to retail electric competition, could adversely affect our results of operations, cash flows and financial condition.

Propane. Our propane operations compete with other propane distributors, primarily on the basis of service and price. Some of our competitors have significantly greater resources. Our ability to grow the propane operations business is contingent upon capturing additional market share, expanding into new markets, and successfully utilizing pricing programs that retain and grow our customer base. Failure to retain and grow our customer base in our propane operations would have an adverse effect on our results of operations, cash flows and financial condition.

Fluctuations in weather may cause a significant variance in our earnings.

Our natural gas distribution, propane operations and natural gas transmission operations, are sensitive to fluctuations in weather conditions, which directly influence the volume of natural gas and propane we transport, sell and deliver to our customers. A significant portion of our natural gas distribution, propane operations and natural gas transmission revenue is derived from the sales and deliveries to residential, commercial and industrial heating customers during the five-month peak heating season (November through March). Other than our Maryland division and Sandpiper Energy which have revenue normalization mechanisms, if the weather is warmer than normal, we sell and deliver less natural gas and propane to customers, and earn less revenue, which could adversely affect our results of operations, cash flows and financial condition. Likewise, if the weather is colder than normal, we sell and deliver more natural gas and propane to customers, and earn more revenue, which could positively affect our results of operations, cash flows and financial condition. Variations in weather from year to year can cause our results of operations, cash flows and financial condition to vary accordingly.

Our electric distribution operation is also affected by variations in weather conditions generally and unusually severe weather conditions. However, electricity consumption is generally less seasonal than natural gas and propane because it is used for both heating and cooling in our service areas.

Natural disasters, severe weather (such as a major hurricane) and acts of terrorism could adversely impact earnings.

Inherent in energy transmission and distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, fires, explosions, sabotage and mechanical problems. Natural disasters and severe weather may damage our assets, cause operational interruptions and result in the loss of human life, all of which could negatively affect our earnings, financial condition and results of operations. Acts of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas, electricity and propane that could negatively affect our operations. Companies in the energy industry may face a heightened risk of exposure to acts of terrorism, which could affect our earnings, financial condition and results of operations. The insurance industry may also be affected by natural disasters, severe weather and acts of terrorism; as a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms, which could adversely affect our results of operations, financial condition and cash flows.

Operating events affecting public safety and the reliability of our natural gas and electric distribution and transmission systems could adversely affect our operations and increase our costs.

Our natural gas and electric operations are exposed to operational events and risks, such as major leaks, outages, mechanical failures and breakdown, operations below the expected level of performance or efficiency, and accidents that could affect public safety and the reliability of our distribution and transmission systems, significantly increase costs and cause loss of customer confidence. If we are unable to recover all or some of these costs from insurance and/or customers through the regulatory process, our results of operations, financial condition and cash flows could be adversely affected.

A security breach disrupting our operating systems and facilities or exposing confidential information may adversely affect our reputation, disrupt our operations and increase our costs.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to system disruptions or cause facility shutdowns. If such an attack or security breach were to occur, our business, our earnings, results of operation and financial condition could be adversely affected. In addition, the protection of customer, employee and Company data is crucial to our operational security. A breach or breakdown of our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could have an adverse effect on our reputation, results of operations and financial condition and could also materially increase our costs of maintaining our system and protecting it against future breakdowns or breaches. We take reasonable precautions to safeguard our information systems from cyber-attacks and security breaches; however, there is no guarantee that the procedures implemented to protect against unauthorized access to our information systems are adequate to safeguard against all attacks and breaches.

Failure to attract and retain an appropriately qualified employee workforce could adversely affect operations.

Our ability to implement our business strategy and serve our customers depends upon our continuing ability to attract, develop and retain talented professionals and a technically skilled workforce, and transfer the knowledge and expertise of our workforce to new employees as our existing employees retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or the future availability and cost of contract labor could adversely affect our ability to manage and operate our business. If we were unable to hire, train and retain appropriately qualified personnel, our results of operations could be adversely affected.

A strike, work stoppage or a labor dispute could adversely affect our operations.

We are party to collective bargaining agreements with labor unions at some of our Florida operations. A strike, work stoppage or a labor dispute with a union or employees represented by a union could cause interruption to our operations and our results could be adversely affected.

Our businesses are capital-intensive, and the increased costs and/or delays of capital projects may adversely affect our future earnings.

Our businesses are capital-intensive and require significant investments in ongoing infrastructure projects. Our ability to complete our infrastructure projects on a timely basis and manage the overall cost of those projects may be affected by the availability of the necessary materials and qualified vendors. Our future earnings could be adversely affected if we are unable to manage such capital projects effectively, or if full recovery of such capital costs is not permitted in future regulatory proceedings.

Our regulated energy business may be at risk if franchise agreements are not renewed, or new franchise agreements are not obtained, which could adversely affect our future results or operating cash flows and financial condition.

Our regulated natural gas and electric distribution operations hold franchises in each of the incorporated municipalities that require franchise agreements in order to provide natural gas and electricity. Ongoing financial results would be adversely impacted in the event that franchise agreements were not renewed. If we are unable to obtain franchise agreements for new service areas, growth in our future earnings could be negatively impacted.

Slowdowns in customer growth may adversely affect earnings and cash flows.

Our ability to increase gross margins in our natural gas, propane and electric distribution businesses is dependent upon growth in the residential construction market, adding new commercial and industrial customers and conversion of customers to natural gas, electricity or propane from other energy sources. Slowdowns in growth may adversely affect our gross margin, earnings and cash flows.

Energy conservation could lower energy consumption, which would adversely affect our earnings.

Federal and state legislative and regulatory initiatives to promote energy efficiency and conservation could lower energy consumption by our customers. In addition, higher costs of natural gas, propane and electricity may cause customers to conserve fuel. To the extent a PSC or FERC does not allow the recovery through customer rates of the costs or lower consumption from energy efficiency or conservation, and our propane margins cannot be increased due to market conditions, our results of operations, cash flows and financial condition may be adversely affected.

Commodity price increases may adversely affect the operating costs and competitive positions of our natural gas, electric and propane operations, which may adversely affect our results of operations, cash flows and financial condition.

Natural Gas/Electricity. Higher natural gas prices can significantly increase the cost of gas billed to our natural gas customers. Increases in the cost of natural gas and other fuels used to generate electricity can significantly increase the cost of electricity billed to our electric customers. Damage to the production or transportation facilities of our suppliers, which decreases their supply of natural gas and electricity, could result in increased supply costs and higher prices for our customers. Such cost increases generally have no immediate effect on our revenues and net income because of our regulated fuel cost recovery mechanisms. However, our net income may be reduced by higher expenses that we may incur for uncollectible customer accounts and by lower volumes of natural gas and electricity deliveries when customers reduce their consumption. Therefore, increases in the price of natural gas and other fuels can adversely affect our operating cash flows, results of operations and financial condition, as well as the competitiveness of natural gas and electricity as energy sources.

Propane. Propane costs are subject to changes as a result of product supply or other market conditions, including weather, economic and political factors affecting crude oil and natural gas supply or pricing. For example, weather conditions could damage production or transportation facilities, which could result in decreased supplies of propane, increased supply costs and higher prices for customers. Such increases in costs can occur rapidly and can negatively affect profitability. There is no assurance that we will be able to pass on propane cost increases fully or immediately, particularly when propane costs increase rapidly. Therefore, average retail sales prices can vary significantly from year-to-year as product costs fluctuate in response to propane, fuel oil, crude oil and natural gas commodity market conditions. In addition, in periods of sustained higher commodity prices, declines in retail sales volumes due to reduced consumption and increased amounts of uncollectible accounts may adversely affect net income.

Refer to *Item 7A*, *Quantitative and Qualitative Disclosures about Market Risk* for additional information.

A substantial disruption or lack of growth in interstate natural gas pipeline transmission and storage capacity or electric transmission capacity may impair our ability to meet customers' existing and future requirements.

In order to meet existing and future customer demands for natural gas and electricity, we must acquire sufficient supplies of natural gas and electricity, interstate pipeline transmission and storage capacity, and electric transmission capacity to serve such requirements. We must contract for reliable and adequate upstream transmission capacity for our distribution systems while considering the dynamics of the interstate pipeline and storage and electric transmission markets, our own on-system resources, as well as the characteristics of our markets. Our financial condition and results of operations would be materially and adversely affected if the future availability of these capacities were insufficient to meet future customer demands for natural gas and electricity. Currently, our Florida natural gas operation relies primarily on one pipeline system, FGT, for most of its natural gas supply and transmission. Our Florida electric operation secures electricity from external parties. Any continued interruption of service from these suppliers could adversely affect our ability to meet the demands of our customers, which could negatively impact our earnings, financial condition and results of operations.

Our use of derivative instruments may adversely affect our results of operations.

Fluctuating commodity prices may affect our earnings and financing costs because our propane operations and PESCO use derivative instruments, including forwards, futures, swaps, puts, and calls, to hedge price risk. While we have risk management policies and operating procedures in place to control our exposure to risk, if we purchase derivative instruments that are not properly matched to our exposure, our results of operations, cash flows, and financial condition may be adversely affected.

PESCO's earnings and operating cash flows are dependent upon optimization of physical assets.

PESCO's earnings and cash flows are based, in part, on its ability to optimize its portfolio of contractual rights to utilize natural gas storage and pipeline assets. The optimization strategy involves utilizing its physical assets to take advantage of differences in natural gas prices between geographic locations and/or time periods. Any change among various pricing points could affect those differentials. In addition, significant increases in the supply of natural gas for PESCO's market areas can reduce its ability to take advantage of pricing fluctuations in the future. Changes in pricing dynamics and supply could have an adverse impact on its optimization activities, earnings and cash flows. PESCO incurs fixed demand fees to acquire its contractual rights to storage and transportation assets. Should commodity prices at various locations or time periods change in such a way that PESCO is not able to recoup these costs from customers, the cash flows and earnings of PESCO and ultimately, the Company, could be adversely impacted.

REGULATORY, LEGAL AND ENVIRONMENTAL RISKS

Regulation of our businesses, including changes in the regulatory environment, may adversely affect our results of operations, cash flows and financial condition.

The Delaware, Maryland and Florida PSCs regulate our utility operations in those states. Eastern Shore is regulated by the FERC. The PSCs and the FERC set the rates that we can charge customers for services subject to their regulatory jurisdiction. Our ability to obtain timely future rate increases and rate supplements to maintain current rates of return depends on regulatory approvals, and there can be no assurance that our regulated operations will be able to obtain such approvals or maintain currently authorized rates of return. When earnings from our regulated utilities exceed the authorized rate of return, the respective regulatory authority may require us to reduce our rates charged to customers in the future.

We may face certain regulatory and financial risks related to pipeline safety legislation.

We are subject to a number of legislative proposals at the federal and state level to implement increased oversight over natural gas pipeline operations and facilities to inspect pipeline facilities, upgrade pipeline facilities, or control the impact of a breach of such facilities. Additional operating expenses and capital expenditures may be necessary to remain in compliance. If new legislation is adopted and we incur additional expenses and expenditures, our financial condition, results of operations and cash flows could be adversely affected, particularly if we are not authorized through the regulatory process to recover from customers some or all of these costs and our authorized rate of return.

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

Our operations are subject to the operating hazards and risks normally incidental to handling, storing, transporting, transmitting and delivering natural gas, electricity and propane to end users. From time to time, we are a defendant in legal proceedings arising in the ordinary course of business. We maintain insurance coverage for our general liabilities in the amount of $51 million, which we believe is reasonable and prudent. However, there can be no assurance that such insurance will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices.

Costs of compliance with environmental laws may be significant.

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These evolving laws and regulations may require expenditures over a long period of time to control environmental effects at our current and former operating sites, especially former MGP sites. To date, we have been able to recover, through regulatory rate mechanisms, the costs associated with the remediation of former MGP sites. However, there is no guarantee that we will be able to recover future remediation costs in the same manner or at all. A change in our approved rate mechanisms for recovery of environmental remediation costs at former MGP sites could adversely affect our results of operations, cash flows and financial condition.

Further, existing environmental laws and regulations may be revised, or new laws and regulations seeking to protect the environment may be adopted and be applicable to us. Revised or additional laws and regulations could result in additional operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable. Any such increase in compliance costs could adversely affect our financial condition and results of operations. Compliance with these legal obligations requires us to commit capital. If we fail to comply with environmental laws and regulations, even if such failure is caused by factors beyond our control, we may be assessed civil or criminal penalties and fines, which could impact our financial condition and results of operations. See *Item 8, Financial Statements and Supplementary Data* (see Note 20*, Environmental Commitments and Contingencies,* in the consolidated financial statements).

Unanticipated changes in our tax provisions or exposure to additional tax liabilities could affect our profitability and cash flow.

We are subject to income and other taxes in the U.S. Changes in applicable U.S. tax laws and regulations, or their interpretation and application, including the possibility of retroactive effect, could affect our tax expense and profitability. In addition, the final determination of any tax audits or related litigation could be materially different from our historical income tax provisions and accruals. Changes in our tax provision or an increase in our tax liabilities, due to changes in applicable law and regulations, the interpretation or application thereof, future changes in the tax rate or a final determination of tax audits or litigation, could have a material adverse effect on our financial position, results of operations or cash flows.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The direction of future U.S. climate change regulation is difficult to predict given the potential for policy changes under different Presidential administrations and Congressional leadership. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions. Even if federal efforts in this area slow, states may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our products. Federal or state legislative initiatives to implement renewable portfolio standards or to further subsidize the cost of solar, wind and other renewable power sources may change the demand for natural gas. We cannot predict the potential impact that such laws or regulations, if adopted, may have on our future business, financial condition or financial results.

Climate changes may impact the demand for our services in the future and could result in more frequent and more severe weather events, which ultimately could adversely affect our financial results.

Significant climatic change creates physical and financial risks for us. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Changes in energy use due to weather variations may affect our financial condition through volatility and/or decreased revenues and cash flows. Extreme weather conditions require more system backups and can increase costs and system stresses, including service interruptions. Severe weather impacts our operating territories primarily through thunderstorms, tornadoes, hurricanes, and snow or ice storms. Weather conditions outside of our operating territories could also have an impact on our revenues and cash flows by affecting natural gas prices. To the extent the frequency of extreme weather events increases, this could increase our costs of providing services. We may not be able to pass on the higher costs to our customers or recover all the costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could adversely affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for lawsuits related to or against greenhouse gas emitters based on the claimed connection between greenhouse gas emissions and climate change, which could impact adversely our business, results of operations and cash flows.

Our certificate of incorporation and bylaws may delay or prevent a transaction that stockholders would view as favorable.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could delay, defer or prevent an unsolicited change in control of Chesapeake Utilities, which may negatively affect the market price of our common stock or the ability of stockholders to participate in a transaction in which they might otherwise receive a premium for their shares over the then current market price. These provisions may also prevent changes in management. In addition, our Board of Directors is authorized to issue preferred stock without stockholder approval on such terms as our Board of Directors may determine. Our common stockholders will be subject to, and may be negatively affected by, the rights of any preferred stock that may be issued in the future.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. Properties.

Offices and other operational facilities

We own or lease offices and other operational facilities in the following locations: Anne Arundel, Cecil, Dorchester, Somerset, Talbot, Wicomico, and Worcester Counties, Maryland; Kent, New Castle and Sussex Counties, Delaware; Accomack County, Virginia; Alachua, Brevard, Broward, Hendry, Jackson, Levy, Martin, Nassau, Okeechobee, Palm Beach, Polk and Volusia Counties, Florida; Orrville and Athens, Ohio; and Pittsburgh, Pennsylvania.

Regulated Energy Segment

We own approximately 1,594 miles of natural gas distribution mains (together with related service lines, meters and regulators) in Kent, New Castle and Sussex Counties, Delaware; and Caroline, Cecil, Dorchester, Wicomico and Worcester Counties, Maryland. We own approximately 2,862 miles of natural gas distribution mains (and related equipment) in Brevard, Broward, Citrus, Clay, DeSoto, Escambia, Gadsden, Gilchrist, Hernando, Hillsborough, Holmes, Indian River, Jackson, Liberty, Marion, Martin, Nassau, Okeechobee, Osceola, Palm Beach, Polk, Seminole, Suwannee, Union, Volusia and Washington Counties, Florida. In addition, we have adequate gate stations to handle receipt of the gas into each of the distribution systems. We also own approximately 97 miles of underground propane distribution mains in Worcester County, Maryland and facilities in Delaware and Maryland, which we use for propane-air injection during periods of peak demand.

We own and operate approximately 486 miles of natural gas transmission pipeline, extending from interconnects at Daleville, Honey Brook and Parkesburg, Pennsylvania; and Hockessin, Delaware, to 96 delivery points in southeastern Pennsylvania, Delaware and the eastern shore of Maryland and approximately 86 miles of natural gas transmission pipeline in Escambia, Indian River, Palm Beach, Pensacola, Polk, Suwannee and Volusia Counties, Florida. We also own approximately 45 percent of the 16-mile natural gas pipeline extending from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. The remaining 55 percent of the natural gas pipeline is owned by Peoples Gas.

We own and operate approximately 16 miles of electric transmission line located in Nassau County, Florida and approximately 905 miles of electric distribution line in Calhoun, Jackson, Liberty and Nassau Counties, Florida.

Unregulated Energy Segment

We own bulk propane storage facilities, with an aggregate capacity of approximately 7.1 million gallons, in Delaware, Maryland, Virginia, Pennsylvania, and Florida. These facilities are located on real estate that is either owned or leased by us.

We own approximately 204 miles of underground propane distribution mains in Delaware; Dorchester, Princess Anne, Queen Anne's, Somerset, Talbot, Wicomico and Worcester Counties, Maryland; Chester and Delaware Counties, Pennsylvania; and Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Marion, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

We own 16 natural gas gathering systems and approximately 2,700 miles of pipeline in central and eastern Ohio.

Florida liens

All of the assets owned by FPU are subject to a lien in favor of the holders of its first mortgage bond securing its indebtedness under its Mortgage Indenture and Deed of Trust. These assets are not subject to any other lien as all other debt is unsecured. FPU owns offices and facilities in the following locations: Alachua, Brevard, Broward, Citrus, Hendry, Jackson, Nassau, Okeechobee, Palm Beach and Volusia Counties, Florida. The FPU assets subject to the lien also include: 1,980 miles of natural gas distribution mains (and related equipment) in its service areas; 16 miles of electric transmission line located in Nassau County, Florida; 905 miles of electric distribution line located in Calhoun, Jackson, Liberty and Nassau Counties in Florida; propane storage facilities with a total capacity of 1.1 million gallons, located in south, central and north Florida; and 76 miles of underground propane distribution mains in Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Indian River, Marion, Martin, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

ITEM 3. Legal Proceedings.

See Note 21, *Other Commitments and Contingencies* to the Consolidated Financial Statements, which is incorporated into Item 3 by reference.

ITEM 4. Mine Safety Disclosures.

Not applicable.

PART II

ITEM 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Common Stock Dividends and Stockholder Information:

Chesapeake Utilities common stock is traded on the New York Stock Exchange ("NYSE") under the ticker symbol CPK. As of February 15, 2019, we had 2,253 holders of record of our common stock. We declared quarterly cash dividends on our common stock totaling $1.4350 per share in 2018 and $1.2800 per share in 2017, and have paid a cash dividend to our common stock stockholders for 58 consecutive years. Future dividend payments and amounts are at the discretion of our Board of Directors and will depend on our financial condition, results of operations, capital requirements, and other factors.

Indentures to our long-term debt contain various restrictions which limit our ability to pay dividends. FPU's first mortgage bonds, which are due in 2022, contain a similar restriction that limits the payment of dividends by FPU. Refer to *Item 8, Financial Statements and Supplementary Data* (see Note 13, *Long-Term Debt*, in the consolidated financial statements) for additional information.

Purchases of Equity Securities by the Issuer

The following table sets forth information on purchases by us or on our behalf of shares of our common stock during the quarter ended December 31, 2018.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
October 1, 2018 through October 31, 2018 [1]	430	$ 83.03	—	—
November 1, 2018 through November 30, 2018	—	—	—	—
December 1, 2018 through December 31, 2018	—	—	—	—
Total	430	$ 83.03	—	—

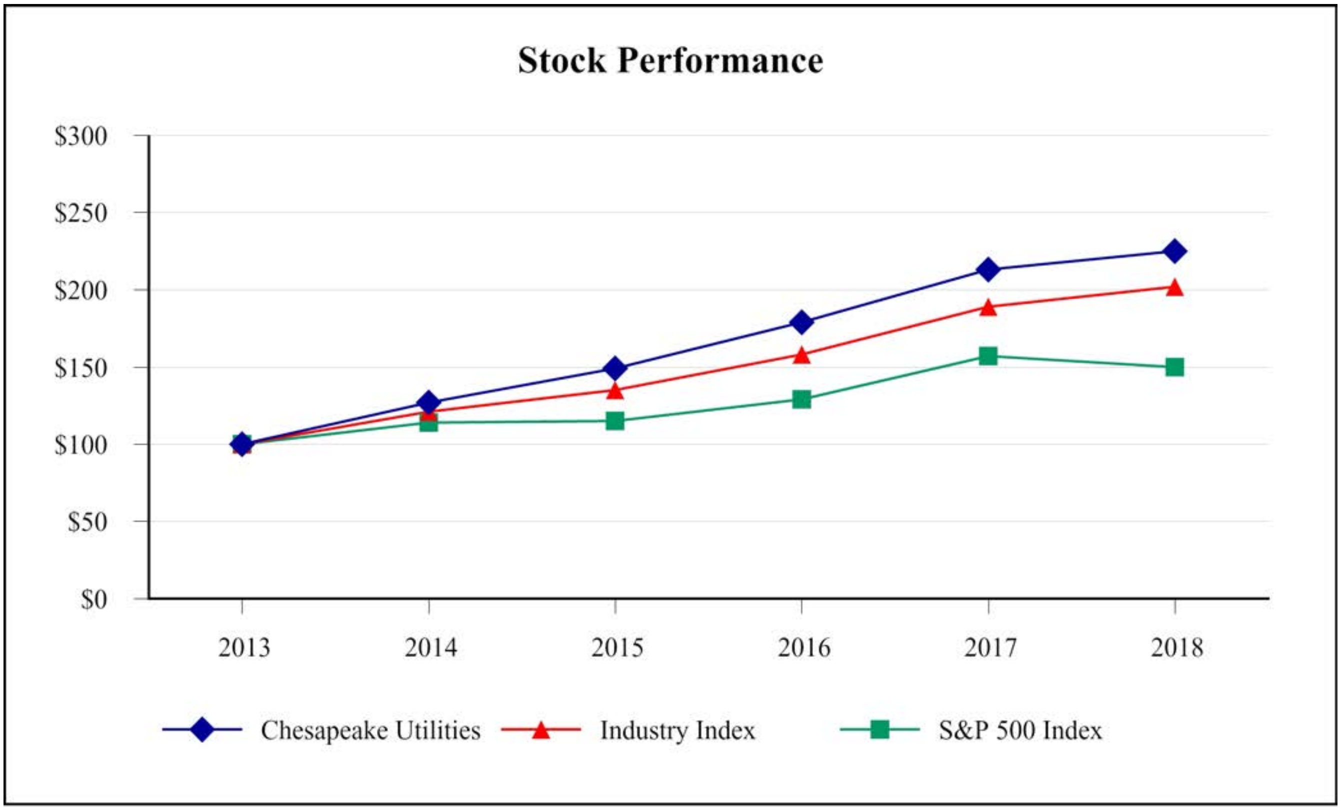
[1] In October 2018, we purchased shares of common stock on the open market for the purpose of reinvesting the dividend on shares held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Non-Qualified Deferred Compensation Plan. The Non-Qualified Deferred Compensation Plan is discussed in detail in *Item 8, Financial Statements and Supplementary Data* (see Note 17*, Employee Benefit Plans*, in the consolidated financial statements). During the quarter, 430 shares were purchased through the reinvestment of dividends.
[2] Except for the purpose described in footnote [1], we have no publicly announced plans or programs to repurchase our shares.

Discussion of our compensation plans, for which shares of our common stock are authorized for issuance, is included in the section of our Proxy Statement captioned "Equity Compensation Plan Information" and is incorporated herein by reference.

Common Stock Performance Graph

The stock performance graph and table below compares cumulative total stockholder return on our common stock during the five fiscal years ended December 31, 2018, with the cumulative total stockholder return of the Standard & Poor's 500 Index and the cumulative total stockholder return of select peers, which include the following companies: Atmos Energy Corporation; Black Hills Corporation; New Jersey Resources Corporation; NiSource Inc.; Northwest Natural Holding Company; NorthWestern Corporation; ONE Gas Inc.; RGC Resources, Inc.; South Jersey Industries, Inc.; Spire Inc.; Unitil Corporation; and Vectren Corporation.

The comparison assumes $100 was invested on December 31, 2013 in our common stock and in each of the foregoing indices and assumes reinvested dividends. The comparisons in the graph below are based on historical data and are not intended to forecast the possible future performance of our common stock.



	2013	2014	2015	2016	2017	2018
Chesapeake Utilities	$ 100	$ 127	$ 149	$ 179	$ 213	**$ 225**
Industry Index	$ 100	$ 121	$ 135	$ 158	$ 189	**$ 202**
S&P 500 Index	$ 100	$ 114	$ 115	$ 129	$ 157	**$ 150**

ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,				
	2018	**2017**	**2016**	**2015**	**2014**
Operating					
(in thousands)					
Revenues					
Regulated Energy	**$ 345,281**	$ 326,310	$ 305,689	$ 301,902	$ 300,442
Unregulated Energy	**420,617**	324,595	203,778	162,108	184,961
Other businesses and eliminations	**(48,409)**	(33,322)	(10,607)	(4,766)	13,431
Total revenues	**$ 717,489**	$ 617,583	$ 498,860	$ 459,244	$ 498,834
Operating income(1)					
Regulated Energy	**$ 79,215**	$ 74,584	$ 71,515	$ 62,137	$ 51,173
Unregulated Energy	**16,901**	12,631	14,066	16,437	11,686
Other businesses and eliminations	**(1,496)**	205	402	418	104
Total operating income	**$ 94,620**	$ 87,420	$ 85,983	$ 78,992	$ 62,963
Net income from continuing operations	**$ 56,580**	$ 58,124	$ 44,675	$ 41,140	$ 36,092
Assets					
(in thousands)					
Gross property, plant and equipment	**$ 1,569,683**	$ 1,312,117	$ 1,175,595	$ 1,007,489	$ 870,125
Net property, plant and equipment	**$ 1,383,972**	$ 1,126,027	$ 986,664	$ 854,950	$ 689,762
Total assets	**$ 1,693,671**	$ 1,414,934	$ 1,229,219	$ 1,067,421	$ 904,469
Capital expenditures	**$ 282,976**	$ 191,103	$ 169,376	$ 195,261	$ 98,057
Capitalization					
(in thousands)					
Stockholders' equity	**$ 518,439**	$ 486,294	$ 446,086	$ 358,138	$ 300,322
Long-term debt, net of current maturities	**316,020**	197,395	136,954	149,006	158,486
Total capitalization	**$ 834,459**	$ 683,689	$ 583,040	$ 507,144	$ 458,808
Current portion of long-term debt	**11,935**	9,421	12,099	9,151	9,109
Short-term debt	**294,458**	250,969	209,871	173,397	88,231
Total capitalization and short-term financing	**$ 1,140,852**	$ 944,079	$ 805,010	$ 689,692	$ 556,148

(1) During the first quarter of 2018, we adopted amended FASB guidance on the presentation of net periodic and postretirement benefit cost ("net benefit cost"). As a result, the components of net benefit cost other than the service component are presented below the subtotal of Operating Income in the consolidated statements of income. All prior periods have been recast to conform to this presentation.

	For the Year Ended December 31,				
	2018	**2017**	**2016**	**2015**	**2014**
Common Stock Data and Ratios					
Basic earnings per share	**$ 3.46**	$ 3.56	$ 2.87	$ 2.73	$ 2.48
Diluted earnings per share	**$ 3.45**	$ 3.55	$ 2.86	$ 2.72	$ 2.47
Diluted earnings per share growth - 1 year	**(2.8)%**	24.1%	5.1%	10.1%	9.3%
Diluted earnings per share growth - 5 year	**8.8 %**	12.3%	8.4%	8.4%	11.6%
Diluted earnings per share growth - 10 year	**10.1 %**	10.7%	9.3%	8.4%	8.5%
Return on average equity	**11.2 %**	12.6%	11.3%	12.1%	12.2%
Common equity / total capitalization	**62.1 %**	71.1%	76.5%	70.6%	65.5%
Common equity / total capitalization and short-term financing	**45.4 %**	51.5%	55.4%	51.9%	54.0%
Capital expenditures / average total capitalization	**37.3 %**	30.2%	31.1%	29.5%	22.9%
Book value per share [1]	**$ 31.65**	$ 29.75	$ 27.36	$ 23.45	$ 20.59
Weighted average number of shares outstanding [1]	**16,369,616**	16,336,789	15,570,539	15,094,423	14,551,308
Shares outstanding at year-end [1]	**16,378,545**	16,344,442	16,303,499	15,270,659	14,588,711
Cash dividends declared per share [1]	**$ 1.44**	$ 1.28	$ 1.20	$ 1.13	$ 1.07
Dividend yield (annualized) [2]	**1.8 %**	1.7%	1.8%	2.0%	2.2%
Book yield [3]	**4.7 %**	4.5%	4.7%	5.1%	5.4%
Payout ratio [4]	**41.6 %**	36.0%	41.8%	41.5%	43.0%
Additional Data					
Customers					
Natural gas distribution	**158,387**	153,537	149,179	144,872	141,227
Electric distribution	**32,185**	32,026	31,695	31,430	31,272
Propane operations	**56,915**	54,760	54,947	53,682	53,272
Total employees	**983**	945	903	832	753

[1] Shares and per share amounts for all periods presented reflect the three-for-two stock split declared on July 2, 2014, effected in the form of a stock dividend, and distributed on September 8, 2014.
[2] Dividend yield (annualized) is calculated by multiplying the fourth quarter dividend by four (4), then dividing that amount by the closing common stock price at December 31.
[3] The book yield is calculated by dividing cash dividends declared per share (for the year) by average book value per share (for the year).
[4] The payout ratio is calculated by dividing cash dividends declared per share (for the year) by basic earnings per share.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

This section provides management's discussion of Chesapeake Utilities and its consolidated subsidiaries, with specific information on results of operations, liquidity and capital resources, as well as discussion of how certain accounting principles affect our financial statements. It includes management's interpretation of our financial results and our operating segments, the factors affecting these results, the major factors expected to affect future operating results as well as investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto in *Item 8, Financial Statements and Supplementary Data*.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A*, Risk Factors*. They should be considered in connection with forward-looking statements contained in this report, or otherwise made by or on behalf of us, since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

The following discussions and those later in the document on operating income and segment results include the use of the term "gross margin," which is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities, and excludes depreciation, amortization and accretion. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by us under our allowed rates for regulated energy operations and under our competitive pricing structures for unregulated energy operations. Our management uses gross margin in measuring our business units' performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

Earnings per share information is presented on a diluted basis, unless otherwise noted.

OVERVIEW AND HIGHLIGHTS

(in thousands except per share data)			Increase			Increase
For the Year Ended December 31,	**2018**	**2017**	**(decrease)**	**2017**	**2016**	**(decrease)**
Operating Income:						
Regulated Energy	**$ 79,215**	$ 74,584	$ 4,631	$ 74,584	$ 71,515	$ 3,069
Unregulated Energy	**16,901**	12,631	4,270	12,631	14,066	(1,435)
Other businesses and eliminations	**(1,496)**	205	(1,701)	205	402	(197)
Total Operating Income	**94,620**	87,420	7,200	87,420	85,983	1,437
Other expense	**(615)**	(2,342)	1,727	(2,342)	(2,328)	(14)
Interest charges	**16,431**	12,645	3,786	12,645	10,639	2,006
Income Before Income Taxes	**77,574**	72,433	5,141	72,433	73,016	(583)
Income taxes	**20,994**	14,309	6,685	14,309	28,341	(14,032)
Net Income	**$ 56,580**	$ 58,124	$ (1,544)	$ 58,124	$ 44,675	$ 13,449
Earnings Per Share of Common Stock:						
Basic	**$ 3.46**	$ 3.56	$ (0.10)	$ 3.56	$ 2.87	$ 0.69
Diluted	**$ 3.45**	$ 3.55	$ (0.10)	$ 3.55	$ 2.86	$ 0.69

2018 compared to 2017

Our net income decreased by approximately $1.5 million or $0.10 per share in 2018, compared to 2017. Key variances included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2017 Reported Results	**$ 72,433**	**$ 58,124**	**$ 3.55**
Adjusting for unusual items:			
Absence of the 2017 deferred tax revaluation benefit associated with the TCJA	—	(14,299)	(0.87)
Net impact of PESCO's MTM activity	10,423	7,602	0.46
One-time separation expenses associated with a former executive	(1,548)	(1,421)	(0.09)
Absence of Xeron expenses, including 2017 wind-down expenses	829	605	0.04
	9,704	(7,513)	(0.46)
Increased (Decreased) Gross Margins:			
Eastern Shore and Peninsula Pipeline service expansions*	9,709	7,082	0.43
Pass-through of lower taxes to regulated energy customers[1]	(9,562)	(6,975)	(0.42)
Natural gas growth (excluding service expansions)	5,911	4,311	0.26
Implementation of Eastern Shore settled rates*[2]	5,803	4,233	0.26
Impact on PESCO from Bomb Cyclone and pipeline capacity constraints	(5,545)	(4,044)	(0.25)
Colder weather	5,046	3,680	0.22
Unregulated Energy growth, excluding PESCO	3,140	2,290	0.14
Florida electric reliability/modernization program*	1,516	1,106	0.07
Florida GRIP*	1,277	932	0.06
Other margin for PESCO operations (net)	(489)	(357)	(0.02)
	16,806	12,258	0.75
Decreased (Increased) Other Operating Expenses[3]:			
Depreciation, asset removal and property taxes	(4,779)	(3,486)	(0.21)
Payroll expense (increased staffing and annual salary increases)	(4,349)	(3,172)	(0.19)
Facilities maintenance costs	(2,687)	(1,960)	(0.12)
Operating expenses to increase staffing, infrastructure and risk management systems necessary to support growth for PESCO[3]	(2,665)	(1,944)	(0.12)
Outside services	(2,182)	(1,592)	(0.10)
Vehicle, other taxes and credit collections	(1,551)	(1,131)	(0.07)
Other employee-related expenses	(1,100)	(802)	(0.05)
Incentive compensation costs	734	535	0.03
Outside regulatory costs	661	482	0.03
Early termination of facility lease due to consolidation of operations facilities	(423)	(309)	(0.02)
	(18,341)	(13,379)	(0.82)
Interest charges	(3,786)	(2,762)	(0.17)
Income taxes - Regulated Energy [1]	—	6,975	0.42
Other income tax effects - primarily the impact of income rate tax changes on Unregulated businesses	—	2,323	0.14
Net Other changes	758	554	0.04
Year ended December 31, 2018 Reported Results	**$ 77,574**	**$ 56,580**	**$ 3.45**

[1] "Pass-through of lower taxes to regulated customers" represents the amounts that have already been refunded to customers or reserves established for future refunds and/or reduced rates to customers in 2018 as a result of lower taxes due to the TCJA. Refunds made to customers are offset by the corresponding decrease in federal income taxes expense and are expected to have no net impact on net income.

[2] Excluding amounts refunded to customers associated with the TCJA, which are broken out separately and discussed in footnote 1.

[3]As a result of increased staffing, infrastructure and risk management systems to support growth for PESCO, operating expenses for PESCO are presented separately.

*** See the Major Projects and Initiatives table.**

2017 compared to 2016

Our net income increased by approximately $13.4 million or $0.69 per share (diluted) in 2017, compared to 2016. Key variances included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2016 Reported Results	$ 73,016	$ 44,675	$ 2.86
Adjusting for unusual items:			
Deferred tax revaluation benefit associated with the TCJA	—	14,299	0.87
Net impact of PESCO's MTM activity	(5,783)	(3,499)	(0.21)
Impact of winding down of Xeron operations and absence of 2016 loss	745	451	0.03
	(5,038)	11,251	0.69
Increased (Decreased) Gross Margins:			
Eight Flags' CHP plant	4,901	2,965	0.19
Implementation of new base rates for Eastern Shore*	3,693	2,234	0.14
PESCO - margin from operations	3,365	2,036	0.13
Natural gas growth (excluding service expansions)	2,818	1,705	0.11
Service expansions*	2,062	1,248	0.08
Florida GRIP*	1,902	1,151	0.07
Aspire Energy rates and management fees	1,125	680	0.04
Customer consumption (non-weather)	721	436	0.03
Implementation of Delaware Division settled rates	831	503	0.03
Wholesale propane sales and margins	678	410	0.03
Retail propane margins	645	390	0.02
Weather impact	578	350	0.02
Margin from Sandpiper System Improvement Rate	291	176	0.01
	23,610	14,284	0.90
(Increased) Decreased Other Operating Expenses:			
Payroll expense	(6,487)	(3,925)	(0.25)
Depreciation, asset removal and property tax costs due to new capital investments	(5,120)	(3,098)	(0.20)
Eight Flags' operating expenses	(2,920)	(1,767)	(0.11)
Benefit and other employee-related expenses	(1,485)	(899)	(0.06)
Regulatory expenses associated with rate filings	(1,005)	(608)	(0.04)
Taxes other than property and income	(739)	(447)	(0.03)
Credit, collections & customer service expenses	515	311	0.02
Outside services and facilities maintenance costs	417	252	0.02
Vehicle expenses	(372)	(225)	(0.01)
Sales and advertising expenses	(259)	(157)	(0.01)
	(17,455)	(10,563)	(0.67)
Increase in outstanding shares from the September 2016 public offering	—	—	(0.16)
Interest charges	(2,006)	(1,214)	(0.08)
Change in other expense	(191)	(115)	(0.01)
Change in effective tax rate prior to tax reform	—	(500)	(0.03)
Net other changes	497	306	0.05
Year ended December 31, 2017 Reported Results	**$ 72,433**	**$ 58,124**	**$ 3.55**

*** See the Major Projects and Initiatives table.**

SUMMARY OF KEY FACTORS

Recently Completed and Ongoing Major Projects and Initiatives

We constantly seek and develop additional projects and initiatives in order to increase shareholder value and serve our customers. The following table represents the major projects recently completed and currently underway. In the future, we will add new projects to this table as such projects are initiated:

	Gross Margin for the Period			
	Year Ended December 31,			Estimate for Fiscal
Project / Initiative	**2016**	**2017**	**2018**	**2019**
(in thousands)				
Florida GRIP	$ 11,552	$ 13,454	**$ 14,731**	$ 16,276
Eastern Shore Rate Case [1]	—	3,693	**9,496**	9,800
Florida Electric Reliability/Modernization Pilot Program [1]	—	94	**1,610**	1,558
New Smyrna Beach, Florida[1]	—	235	**1,409**	1,409
2017 Eastern Shore System Expansion - including interim services [1]	—	483	**8,015**	15,709
Northwest Florida Expansion[1]	—	—	**3,485**	6,500
Western Palm Beach County, Florida Expansion[1]	—	—	**54**	1,250
Marlin Gas Services	—	—	**110**	4,475
Ohl propane acquisition (rolled into Sharp)	—	—	**—**	1,200
Total	$ 11,552	$ 17,959	**$ 38,910**	$ 58,177

[1] Gross margin amount included in this table has not been adjusted to reflect the impact of the TCJA. The refunds and rate reductions implemented were or will be, offset by lower federal income taxes due to the TCJA.

Ongoing Growth Initiatives

Florida GRIP

Florida GRIP is a natural gas pipe replacement program approved by the Florida PSC that allows automatic recovery, through rates, of costs associated with the replacement of mains and services. Since the program's inception in August 2012, we have invested $127.0 million to replace 268 miles of qualifying distribution mains, including $13.3 million and $10.8 million during 2018 and 2017, respectively. GRIP generated additional gross margin of $1.3 million in 2018 compared to 2017.

Regulatory Proceedings

Eastern Shore Rate Case

Eastern Shore's rate case settlement agreement became final on April 1, 2018, with settlement rates effective August 1, 2017 and tax-adjusted rates effective January 1, 2018. The final agreement increases Eastern Shore's operating income by $6.6 million, representing an estimated $9.8 million in additional margin from base rates offset by an estimated $3.2 million in lower federal income tax expense for Eastern Shore resulting from the TCJA. In 2018, Eastern Shore recognized incremental gross margin of approximately $5.8 million and provided rate reductions to customers totaling approximately $3.3 million as a result of the new rates. Annual margin from the new rates in future years is estimated to be $9.8 million.

Florida Electric Reliability/Modernization Pilot Program

In December 2017, the Florida PSC approved a $1.6 million annualized rate increase, effective January 2018, for the recovery of a limited number of investments and costs related to reliability, safety and modernization for our Florida electric distribution system. This increase will continue through at least the last billing cycle of December 2019. For the years ended December 31, 2018 and 2017, incremental gross margin of $1.5 million and $94,000, respectively, was generated by this program.

Major Projects and Initiatives Currently Underway

New Smyrna Beach, Florida Project

In the fourth quarter of 2017, we commenced construction of a 14-mile natural gas transmission pipeline to serve current customers and planned customer growth in the New Smyrna Beach service area. A portion of the project was placed into service at the end of 2017, and the remainder was placed into service during the fourth quarter of 2018. For the year ended December 31, 2018, the project generated incremental gross margin of approximately $1.2 million compared to 2017 and is expected to generate $1.4 million in annual gross margin going forward.

2017 Eastern Shore System Expansion Project

From November 2017 to December 2018, Eastern Shore substantially completed the construction of a system expansion project that increased its capacity by 26 percent. The first phase of the project was placed into service in December 2017. The project generated $7.5 million in incremental gross margin, including margin from interim services, for the year ended December 31, 2018, compared to 2017. It is expected to produce annual gross margin of approximately $15.7 million in 2019, $15.8 million from 2020 through 2022 and $13.2 million thereafter.

Northwest Florida Expansion Project

In our first expansion of natural gas service into Northwest Florida, Peninsula Pipeline completed construction of transmission lines and the Florida natural gas division completed construction of lateral distribution lines to serve several customers. The project was placed into service in May 2018 and generated gross margin of $3.5 million during 2018. The estimated annual gross margin going forward is $6.5 million.

Western Palm Beach County Belvedere, Florida Project

Peninsula Pipeline is constructing four transmission lines to bring natural gas to our distribution system in West Palm Beach, Florida. The first phase of this project was placed into service in December 2018 and generated gross margin of $54,000 during 2018. We expect to complete the remainder of the project in phases through early 2020 and estimate gross margin of $1.3 million in 2019 and approximately $5.4 million in future years once fully in service.

Marlin Gas Services

In December 2018, Marlin Gas Services, our newly created subsidiary, acquired certain operating assets of Marlin Gas Transport, a supplier of mobile compressed natural gas utility and pipeline solutions. The acquisition will allow us to offer solutions to address supply interruption scenarios and provide other unique applications where pipeline supplies are not available or cannot meet customer requirements. Operating margins generated in 2018 were immaterial, given the date of acquisition. We estimate that this acquisition will generate additional annual gross margin of approximately $4.5 million in 2019, with potential for additional growth in future years.

Ohl Propane Acquisition

In December 2018, Sharp Energy acquired certain propane customers and operating assets of R.F. Ohl Fuel Oil, Inc ("Ohl"). Ohl provided propane distribution service to approximately 2,500 residential and commercial customers in Pennsylvania, located between two of Sharp's existing districts. The customers and assets acquired from Ohl have been assimilated into Sharp. Operating margins generated in 2018 were immaterial, given the date of acquisition. We estimate that this acquisition will generate additional gross margin of approximately $1.2 million for Sharp in 2019, with the potential for additional growth in future years.

Future Projects Not Included in the Table Above

Del-Mar Energy Pathway Project

In September 2018, Eastern Shore filed for FERC authorization to construct the Del-Mar Energy Pathway project to provide an additional 14,300 Dts/d of capacity to four customers. The benefits of this project include additional natural gas transmission pipeline infrastructure in eastern Sussex County, Delaware, and the initial extension of Eastern Shore’s pipeline system into Somerset County, Maryland. The estimated annual gross margin from this project is $5.1 million. Eastern Shore anticipates that this project will be fully in-service by the third quarter of 2020, assuming that the FERC authorizes the project by August 2019.

Other Major Factors Influencing Gross Margin

Weather and Consumption

The impact of colder temperatures on customer consumption during 2018 contributed $5.0 million in incremental gross margin compared to 2017. While 2018 was colder than 2017, it was still 1.1 percent warmer than normal (average across our service territories). Normal weather during 2018 would have generated $4.0 million in additional gross margin. The following table summarizes HDD and CDD variances from the 10-year average HDD/CDD ("Normal") for 2018, 2017 and 2016.

HDD and CDD Information

For the Years Ended December 31,	2018	2017	Variance	2017	2016	Variance
Delmarva						
Actual HDD	**4,251**	3,800	451	3,800	3,979	(179)
10-Year Average HDD ("Normal")	**4,379**	4,374	5	4,374	4,453	(79)
Variance from Normal	**(128)**	(574)		(574)	(474)	
Florida						
Actual HDD	**780**	533	247	533	672	(139)
10-Year Average HDD ("Normal")	**800**	818	(18)	818	828	(10)
Variance from Normal	**(20)**	(285)		(285)	(156)	
Ohio						
Actual HDD	**5,845**	5,126	719	5,126	5,529	(403)
10-Year Average HDD ("Normal")	**5,823**	5,914	(91)	5,914	5,918	(4)
Variance from Normal	**22**	(788)		(788)	(389)	
Florida						
Actual CDD	**3,105**	3,013	92	3,013	3,152	(139)
10-Year Average CDD ("Normal")	**2,889**	2,865	24	2,865	2,820	45
Variance from Normal	**216**	148		148	332	

Hurricane Michael Update

In October 2018, Hurricane Michael passed through FPU's electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure resulting in 100 percent of its customers losing electrical service. FPU has restored service to those customers who were able to accept service following Hurricane Michael after a significant hurricane restoration effort. In conjunction with restoring these services, FPU expended over $60 million to restore service, which has been recorded as new plant and equipment or charged against FPU’s accumulated depreciation and storm reserve. We have begun preparing the necessary regulatory filings to seek recovery for the costs incurred, including replenishment of our storm reserve. In conjunction with the hurricane-related expenditures, we executed two 13-month unsecured term loans as temporary financing, each in the amount of $30 million. The interest cost associated with these loans is LIBOR plus 75 basis points. One of the term loans was executed in December 2018 and the other was executed in January 2019. The storm did not have a material impact on our financial results in 2018 as services were restored to a majority of our customers, and is not expected to have a significant impact going forward as we will be seeking recovery of the storm costs through rates.

Natural Gas Distribution Customer and Consumption Growth

Customer growth for our natural gas distribution operations generated $3.9 million in additional gross margin for the year ended December 31, 2018 compared to the same period in 2017. The additional margin was generated from an increase of approximately 3.3 percent in the average number of residential customers served, growth in volumes delivered to commercial and industrial customers on the Delmarva Peninsula and in Florida, and new service initiated to customers in Northwest Florida. Higher residential and commercial customers' consumption increased gross margin by $2.0 million for the year ended December 31, 2018 compared to the same period in 2017.

(in thousands)	**Increase (decrease) in Margin in 2018**
Customer growth:	
Residential	$ 1,604
Commercial and industrial, excluding new service in Northwest Florida	1,322
New service in Northwest Florida	987
Total customer growth	3,913
Volume growth:	
Residential	655
Commercial and industrial	1,522
Other - including unbilled revenue	(179)
Total volume growth	1,998
Total natural gas distribution growth	$ 5,911

Propane Operations

The Company's Florida and Mid-Atlantic propane distribution operations continue to pursue a multi-pronged growth plan, which includes: targeting retail and wholesale customer growth in existing markets, both organically as well as through acquisitions; incremental growth from recent and planned start-ups in new markets; targeting new community gas systems in high growth areas; further build-out of the Company's propane vehicular platform through AutoGas fueling stations; and optimization of its supply portfolio to generate incremental margin opportunities. Our propane operations and AutoGas segment install and support propane vehicle conversion systems for vehicle fleets, including converting fleets to bi-fuel propane-powered engines and providing on-site fueling infrastructure. These operations generated $4.9 million during the year ended December 31, 2018 compared to 2017. Colder temperatures accounted for $2.2 million of the margin increase. The balance of the gross margin increase for the year reflected the impact of the growth strategies discussed above, including generating approximately a four-percent increase in customers. Supply management initiatives have also increased retail propane margins from many customer classes and margin from wholesale propane sales.

PESCO

In 2018, PESCO's gross margin increased by $4.4 million compared to 2017. Higher gross margin in 2018 from PESCO resulted from the following:

(in thousands)	**Margin Impact**
Net impact of PESCO's MTM activity	$ 10,423
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [1]	(3,284)
Loss for the Mid-Atlantic retail portfolio caused by pipeline capacity constraints in January and warm weather in February 2018 [1]	(2,261)
Other margin for PESCO operations (net)	(489)
Total Change in Gross Margin for PESCO in 2018	**$ 4,389**

[1] The 2018 Bomb Cyclone refers to the high-intensity winter storms in early January 2018 that impacted the Mid-Atlantic region and which had a residual impact on our businesses through the month of February. The exceedingly high demand and associated impacts on pipeline capacity and gas supply in the Mid-Atlantic region created significant, unusual costs for PESCO. While such concerted impacts will recur infrequently, our management revisited and refined its risk management strategies and implemented additional controls.

For the year ended December 31, 2018, PESCO reported an operating loss of $1.4 million, compared to an operating loss of $3.1 million during the prior year period. The year-over-year improvement in operating loss reflects primarily increased gross margin of $4.4 million, for the reasons discussed in the table above, which was offset by an increase of $2.7 million in other operating expenses as a result of increased staffing, infrastructure and risk management system costs to ensure the appropriate infrastructure is in place as PESCO executes its growth strategy.

Xeron

Xeron's operations were wound down during the second quarter of 2017. Operating income in 2018 improved by $718,000 over 2017, due to the absence of an operating loss and wind-down expenses incurred in 2017.

REGULATED ENERGY

For the Year Ended December 31,	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
(in thousands)						
Revenue	**$ 345,281**	$ 326,310	$ 18,971	$ 326,310	$ 305,689	$ 20,621
Cost of sales	**121,828**	118,769	3,059	118,769	109,609	9,160
Gross margin	**223,453**	207,541	15,912	207,541	196,080	11,461
Operations & maintenance	**97,741**	90,931	6,810	90,931	86,434	4,497
Gain from a settlement	**(130)**	(130)	—	(130)	(130)	—
Depreciation & amortization	**31,876**	28,554	3,322	28,554	25,677	2,877
Other taxes	**14,751**	13,602	1,149	13,602	12,584	1,018
Other operating expenses	**144,238**	132,957	11,281	132,957	124,565	8,392
Operating Income	**$ 79,215**	$ 74,584	$ 4,631	$ 74,584	$ 71,515	$ 3,069

2018 compared to 2017

Operating income for the Regulated Energy segment for 2018 was $79.2 million, an increase of $4.6 million, or 6.2 percent, compared to 2017. Adjusting for the estimated pass-through of lower taxes to customers, operating income increased by $14.2 million or 19.0 percent, compared to the prior year. The growth in operating income was due to an increase in gross margin of $15.9 million, $25.5 million adjusted for the tax pass-through, partially offset by $11.3 million in higher other operating expenses to support the margin growth. Growth in 2018 was strong across all business units in the regulated energy segment with the most significant contributions coming from expansions at Peninsula Pipeline and Eastern Shore, customer and consumption growth in the natural gas distribution operations, colder weather, and safety and reliability investments in the Florida electric and gas distribution operations.

Gross Margin

Items contributing to the year-over-year gross margin increase are listed in the following table:

(in thousands)	Margin Impact
Eastern Shore and Peninsula Pipeline service expansions	$ 9,709
Natural gas growth (excluding service expansions)	5,911
Implementation of Eastern Shore settled rates	5,803
Colder weather	1,788
Florida electric reliability/modernization program	1,516
Florida GRIP	1,277
Other	(530)
Total	25,474
Less: Pass-through to regulated customers of lower taxes as a result of the TCJA*	(9,562)
Year-over-year increase in gross margin	**$ 15,912**

*As a result of the TCJA and resulting directives by federal and state regulatory commissions, we reserved or refunded to customers of our regulated businesses an estimated $9.6 million in 2018. In some jurisdictions, we have paid refunds to customers, while in other jurisdictions, we have established reserves until agreements are approved and changes are made to customer rates. The reserves and lower customer rates are equal to the estimated reduction in federal income taxes due to the TCJA and have no material impact on after-tax earnings from the Regulated Energy segment.

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Service Expansions

The following natural gas pipeline service expansions generated additional gross margin of $9.7 million in 2018:

- $7.5 million from Eastern Shore's services, including those provided to customers on an interim basis, in conjunction with portions of Eastern Shore's 2017 Expansion Project that were placed in service, partially offset by the absence of $2.0 million in short-term contracts that were replaced by long-term service agreements; and
- $4.7 million generated by Peninsula Pipeline from the New Smyrna Beach and Northwest Pipeline Expansion Projects.

Natural Gas Growth (excluding service expansions)
We generated increased gross margin of $5.9 million in 2018 from natural gas growth and consumption (excluding service expansions) primarily from the following:

- $2.3 million and $1.6 million, respectively, from residential and commercial customer growth in Florida and on the Delmarva Peninsula; and
- $2.0 million from higher sales volumes (consumption) on the Delmarva Peninsula and in Florida that were not driven by weather.

Implementation of Eastern Shore's Settled Rates
Eastern Shore generated additional gross margin of $5.8 million from the implementation of new rates as a result of its rate case filing. See *Note 19, Rates and Other Regulatory Activities*, to the consolidated financial statements for additional details.

Colder Weather
Temperatures during 2018 were 1.1 percent warmer than normal (average across our service territories), compared to 14.8 percent warmer than normal (average across our service territories) during 2017. The colder weather increased usage and generated $1.8 million in additional margin for 2018.

Florida Electric Reliability/Modernization Program
This program generated incremental gross margin of $1.5 million in 2018. See *Note 19, Rates and Other Regulatory Activities,* to the consolidated financial statements for additional details.

Florida GRIP
Continued investment in the Florida GRIP generated additional gross margin of $1.3 million in 2018 compared to 2017.

Impact of the TCJA on Customer Rates
Implementation of the TCJA in 2018, decreased gross margin by $9.6 million due to refunds and reserves for future refunds and/or rate reductions to customers. The decrease in gross margin was offset by an equal reduction in federal income taxes, and, therefore had no impact on net income. See Note 19, *Rates and Other Regulatory Activities*, for additional discussion of the TCJA impact.

<u>*Other Operating Expenses*</u>

Other operating expenses increased by $11.3 million, incurred primarily to support business growth. The significant factors contributing to the increase in other operating expenses included:

- $4.2 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $2.4 million in higher payroll expenses related to staffing and salary increases. This increase was partially offset by lower incentive compensation costs of $737,000;
- $2.2 million in higher costs related to outside services to support growth;
- $1.7 million in higher facilities and maintenance costs to maintain system integrity;
- $869,000 in higher vehicle, other taxes and credit collections; and
- $514,000 in other employee-related expenses.

2017 compared to 2016

Operating income for the Regulated Energy segment for 2017 was $74.6 million, an increase of $3.1 million, or 4.3 percent, compared to 2016. The increased operating income was due to an increase in gross margin of $11.5 million, partially offset by higher other operating expenses of $8.4 million.

Gross Margin

Items contributing to the year-over-year gross margin increase are listed in the following table:

(in thousands)	**Margin Impact**	
Implementation of Eastern Shore rates	$	3,693
Natural gas growth (including customer and consumption growth but excluding service expansions)		2,818
Eastern Shore and Peninsula Pipeline service expansions		2,062
Florida GRIP		1,902
Implementation of Delaware Division rates (2017 Settlement)		831
New natural gas transmission and distribution service to Eight Flags CHP plant		537
Other		(382)
Year-over-year increase in gross margin	$	11,461

The following is a narrative discussion of significant items in the foregoing table for which we have additional information that we believe is necessary to understand the information disclosed in the table.

Implementation of Eastern Shore Rates
Eastern Shore generated additional gross margin of $3.7 million from implementation of new base rates in 2017 as a result of its rate case filing. See *Note 19, Rates and Other Regulatory Activities*, to the consolidated financial statements for additional details.

Natural Gas Growth (including customer and consumption growth but excluding service expansions)
In 2017, growth in customers and consumption generated increased gross margin of $2.8 million including:

- $1.6 million from a 3.8 percent increase in the average number of residential customers served by the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers served; and
- $1.2 million from our Florida natural gas distribution operations' customer growth, with approximately two-thirds of the margin growth generated from commercial and industrial customers and one-third generated from new residential customers.

Service Expansions
We generated additional gross margin of $2.1 million in 2017 from the following natural gas services:

- $1.2 million from short-term firm service available through Eastern Shore's natural gas receipt capacity from TETLP;
- $433,000 from interim services provided by Eastern Shore after a portion of an expansion project was placed in service in December 2017;
- $298,000 from Eastern Shore's increased long-term firm service rates for an industrial customer in Delaware; and
- $235,000 generated by Peninsula Pipeline from the New Smyrna Beach Expansion Project.

Florida GRIP
Increased investment in GRIP generated additional gross margin of $1.9 million in 2017 compared to 2016.

Implementation of Delaware Division Rates
Our Delaware Division generated additional gross margin of $831,000 as a result of its rate case settlement in 2017.

Service to Eight Flags
We generated additional gross margin of $537,000 in 2017, compared to 2016, from new natural gas transmission and distribution services provided to Eight Flags' CHP plant.

Other Operating Expenses

Other operating expenses increased by $8.4 million. The significant components of the increase in other operating expenses included:

- $4.1 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $3.6 million in higher payroll expenses for additional personnel to support growth; and
- $1.0 million in increased regulatory expenses, due primarily to costs associated with Eastern Shore's rate case filing in 2017; which was partially offset by
- $529,000 in lower credit, collection and customer services expenses.

UNREGULATED ENERGY

For the Year Ended December 31,	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
(in thousands)						
Revenue	**$ 420,617**	$ 324,595	$ 96,022	$ 324,595	$ 203,778	$ 120,817
Cost of sales	**336,819**	252,023	84,796	252,023	138,816	113,207
Gross margin	**83,798**	72,572	11,226	72,572	64,962	7,610
Operations & maintenance	**54,263**	48,576	5,687	48,576	42,437	6,139
Depreciation & amortization	**8,845**	7,954	891	7,954	6,386	1,568
Other taxes	**3,789**	3,411	378	3,411	2,073	1,338
Other operating expenses	**66,897**	59,941	6,956	59,941	50,896	9,045
Operating Income	**$ 16,901**	$ 12,631	$ 4,270	$ 12,631	$ 14,066	$ (1,435)

2018 Compared to 2017

Operating income for the Unregulated Energy segment for 2018 was $16.9 million, an increase of $4.3 million compared to 2017. The increased operating income was due to an increase in gross margin of $11.2 million, which was partially offset by an increase of $7.0 million in other operating expenses.

Given the impact of the MTM gain and loss recorded by PESCO in the first quarter of 2018 and fourth quarter of 2017, respectively, and the increased staffing, infrastructure and risk management systems implemented to support PESCO's growth, the Company is continuing to present PESCO's 2018 results separate from the rest of its Unregulated Energy segment:

Unregulated Energy, excluding PESCO

For the Year Ended December 31,	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
(in thousands)						
Gross margin	**$ 77,197**	$ 70,360	$ 6,837	$ 70,360	$ 60,332	$ 10,028
Depreciation, amortization and property taxes	**9,678**	9,081	597	9,081	7,047	2,034
Other operating expenses	**49,197**	45,504	3,693	45,504	41,085	4,419
Operating Income	**$ 18,322**	$ 15,775	$ 2,547	$ 15,775	$ 12,200	$ 3,575

Gross Margin

Items contributing to the year-over-year increase in gross margin are listed in the following table:

(in thousands)		Margin Impact
Propane Operations		
Customer growth, increased sales volumes (non-weather related) and other factors		2,947
Additional customer consumption from colder weather		2,241
Decreased margins per gallon in certain customer classes		(977)
Service, appliances and other fees		404
Higher wholesale propane margins and sales		287
Aspire Energy		
Higher customer consumption from colder weather		1,017
Increase in rates effective on various dates in 2018		602
Other		316
Year-over-year increase in gross margin	**$**	**6,837**

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Propane Operations - Increased Margin Driven by Growth and Other Factors
Gross margin increased by $2.9 million, due to increased propane sales as a result of customer growth, higher sales volumes and other factors in Florida and the Mid-Atlantic region.

Propane Operations - Increased Customer Consumption - (Weather)
Gross margin increased by $2.2 million, due primarily to increased customer consumption in the Mid-Atlantic region as a result of colder temperatures in 2018 compared to 2017.

Aspire Energy - Increased Customer Consumption (Weather)
Gross margin increased by $1.0 million, as a result of increased natural gas delivered, due primarily to colder temperatures in 2018 when compared to temperatures in 2017.

Propane Operations - Decreased retail margins per gallon for certain customer classes
Gross margin decreased by $1.0 million, driven by lower sales prices for primarily two customer classes in response to market conditions.

Propane Operations - Services, appliances and other fees
Gross margin increased by $404,000, from services, appliances and other fees.

Aspire Energy - Increased Margin Driven by Changes in Rates
Gross margin increased by $602,000, due primarily to changes in customer rates on various dates during 2018.

Wholesale Propane Margins
Gross margin increased by $287,000, in 2018 due to a higher realized margin per gallon and an increase in volumes delivered for the Mid-Atlantic propane operations.

PESCO

For the Year Ended December 31,	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
(in thousands)						
Gross margin	**$ 6,601**	$ 2,212	$ 4,389	$ 2,212	$ 4,630	$ (2,418)
Depreciation, amortization and property taxes	**604**	206	398	206	18	188
Other operating expenses	**7,418**	5,150	2,268	5,150	2,746	2,404
Operating Income	**$ (1,421)**	$ (3,144)	$ 1,723	$ (3,144)	$ 1,866	$ (5,010)

In 2018, PESCO's gross margin increased by $4.4 million compared to 2017. Higher gross margin in 2018 from PESCO resulted from the following:

(in thousands)	Margin Impact
Net impact of PESCO's MTM activity	$ 10,423
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [1]	(3,284)
Loss for the Mid-Atlantic retail portfolio caused by pipeline capacity constraints in January and warm weather in February 2018 [1]	(2,261)
Other margin for PESCO operations (net)	(489)
Total Change in Gross Margin for PESCO in 2018	**$ 4,389**

[1] The 2018 Bomb Cyclone refers to the high-intensity winter storms in early January 2018 that impacted the Mid-Atlantic region and which had a residual impact on our businesses through the month of February. The exceedingly high demand and associated impacts on pipeline capacity and gas supply in the Mid-Atlantic region created significant, unusual costs for PESCO. While such concerted impacts are not expected to occur frequently, our management revisited and refined its risk management strategies and implemented additional controls.

Other Operating Expenses

Other operating expenses increased by $7.0 million in 2018 compared to 2017. The significant components of the increase in operating expenses included:

- $2.7 million in higher expenses as a result of increased staffing, infrastructure and risk management system costs to ensure the appropriate infrastructure is in place as PESCO executes its growth strategy;
- $1.9 million in higher payroll expense for additional personnel to support growth and increased deliveries driven by the colder weather in 2018 compared to 2017;
- $953,000 in higher facilities maintenance costs as a result of ongoing compliance activities;
- $597,000 in higher depreciation, amortization and property tax expense due to increased investments; and
- $586,000 in other employee-related costs.

2017 Compared to 2016

Operating income for the Unregulated Energy segment for 2017 was $12.6 million, a decrease of $1.4 million compared to 2016. The decreased operating income was due to an increase in gross margin of $7.6 million, which was offset by an increase of $9.0 million in other operating expenses. Gross margin and operating income, excluding the impact of the unrealized MTM loss on energy-related derivatives, grew by $13.4 million, or 20.6 percent, and $4.3 million, or 30.9 percent, respectively, during 2017, compared to 2016.

Gross Margin

Items contributing to the year-over-year increase in gross margin are listed in the following table:

(in thousands)	**Margin Impact**
PESCO - unrealized MTM loss	$ (5,783)
Eight Flags' CHP plant	4,365
PESCO - margin from operations	3,365
Customer consumption - weather and other	2,144
Pricing amendments to Aspire Energy's long-term sales agreements	1,125
Higher wholesale propane sales and margins	678
Wind-down of Xeron operations	658
Improved retail propane margins	645
Other	413
Year-over-year increase in gross margin	$ 7,610

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Natural Gas Marketing - PESCO
PESCO's gross margin decreased by $2.4 million due primarily to $5.8 million in the unrealized MTM loss related to PESCO's financial derivatives contracts that were valued at the end of the year; offset by $3.4 million in additional gross margin generated primarily from: (a) providing natural gas to end users within one customer pool pursuant to a supplier agreement with Columbia Gas of Ohio, which expired on March 31, 2017, and (b) an increase in commercial and industrial customers served in Florida.

Eight Flags
Eight Flags' CHP plant generated $4.4 million in additional gross margin in 2017 during its first full year of operations.

Customer Consumption - Weather and Other
Gross margin increased by $2.1 million due to higher, non-weather related sales volumes for our propane operations, increased weather driven demand at Aspire Energy and for our Mid-Atlantic propane operations in the fourth quarter and for our Florida propane operations during the third quarter of 2017.

Pricing Amendments to Aspire Energy's Long-Term Agreements
An increase in gross margin of $1.1 million due to favorable pricing amendments to several long-term sales agreements.

Wholesale Propane Sales and Margins
Gross margin increased by $678,000, due primarily to increased volumes and favorable supply management activities for the Mid-Atlantic propane operations, as well as higher margins in Florida.

Wind-down of Xeron operations

The absence of the prior year operating loss from Xeron increased gross margin by $658,000.

Retail Propane Margins
Gross margin increased by $645,000, due primarily to favorable supply management activities and market conditions.

Other Operating Expenses

Other operating expenses increased by $9.0 million. The significant components of the increase in other operating expenses included:

- $2.9 million in higher operating expenses by Eight Flags' CHP plant in support of the margin generated;
- $2.9 million in higher payroll costs for additional personnel to support growth;
- $1.0 million in higher depreciation expense, of which $476,000 relates to lower depreciation recorded in 2016 as a result of the final accounting for the acquisition of Aspire Energy;
- $1.0 million in higher benefits and employee-related costs in 2017; and
- $594,000 in higher taxes, other than property and income taxes.

OTHER EXPENSE, NET

Other expense, net for 2018 was $615,000, and was $2.3 million for both 2017 and 2016. Other expense, net includes non-operating investment income (expense), interest income, late fees charged to customers, gains or losses from the sale of assets for our unregulated business and pension and other benefits expense. The decrease in other expense, net in 2018 was due to a decrease in pension expenses when compared to 2017 and the absence of a lease termination payment which occurred in 2017.

INTEREST CHARGES

2018 Compared to 2017

Interest charges for 2018 increased by approximately $3.8 million, compared to 2017. The increase is attributable $3.3 million in additional interest due to higher short-term borrowings and higher short-term interest rates as well as $1.5 million in additional interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017 and the NYL Shelf Notes (Series A) in May 2018. These increases were partially offset by allowance for funds used during construction ("AFUDC") of approximately $1.1 million, primarily from Eastern Shore and Peninsula Pipeline.

2017 Compared to 2016

Interest charges for 2017 increased by approximately $2.0 million compared to 2016. The increase is attributable to $1.3 million in additional interest due to higher short-term borrowings and $1.0 million in additional interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017. The balance of the increase reflects higher interest expense on customer deposits.

INCOME TAXES

2018 Compared to 2017

Income tax expense was $21.0 million for 2018 compared to $14.3 million for 2017. The increase in income tax expense in 2018 was due primarily to enactment of the TCJA in 2017, which resulted in a one-time decrease in our deferred income tax expense for 2017 by $14.3 million. Our effective income tax rate was 27.1 percent in 2018 compared to 19.8 percent in 2017. Our lower effective tax rate in 2017 resulted from the one-time revaluation of deferred tax assets and liabilities from our Unregulated Energy business as a result of the enactment of the TCJA.

2017 Compared to 2016

Income tax expense was $14.3 million for 2017, compared to $28.3 million in 2016. Our effective tax rate was 19.8 percent in 2017, compared to 38.8 percent in 2016. The lower tax expense and effective tax rate in 2017 was due primarily to enactment of the TCJA in December 2017.

LIQUIDITY AND CAPITAL RESOURCES

Capital expenditures for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures were $283.0 million in 2018 (including the purchase of certain assets from Marlin CNG Services and Ohl), $191.1 million in 2017 (including the purchase of certain assets of ARM) and $169.4 million in 2016. The 2018 capital expenditures also includes over $60.0 million of restoration costs associated with repairing damages caused by Hurricane Michael to our electric distribution operations' service territory in Northwest Florida.

The following table shows the 2019 capital expenditure budget of $168.2 million by segment and by business line:

(dollars in thousands)		
Regulated Energy:		**Budget Capital Expenditures**
Natural gas distribution	$	64,143
Natural gas transmission		66,787
Electric distribution		5,949
Total Regulated Energy		136,879
Unregulated Energy:		
Propane operations		11,870
Energy transmission		8,345
Other unregulated energy		1,416
Total Unregulated Energy		21,631
Other:		
Corporate and other businesses		9,705
Total Other		9,705
Total 2019 capital expenditures budget	**$**	**168,215**

The 2019 budget, excluding acquisitions, includes: Eastern Shore's Del-Mar Energy Pathway Project, Florida's Palm Beach County Western Expansion and other potential pipeline projects, continued expenditures under Florida GRIP, further expansions of our natural gas distribution and transmission systems, continued natural gas infrastructure improvement activities, information technology systems, new buildings and facilities, and other strategic initiatives and investments.

The capital expenditure projection is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities, availability of capital and other factors discussed in Item 1A. Risk Factors. Over the last five years, our actual capital expenditures have averaged 98 percent of the initial budgeted capital expenditures for those years.

The timing of capital expenditures can vary based on delays in regulatory approvals, securing environmental approvals and other permits. The regulatory application and approval process has lengthened in the past few years, and we expect this trend to continue.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings. This commitment, along with adequate and timely rate relief for our regulated energy operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost, which will benefit our customers, creditors, employees and stockholders.

Our capitalization as of December 31, 2018 and 2017 follows:

(in thousands)	**December 31, 2018**			December 31, 2017		
Long-term debt, net of current maturities	**$**	**316,020**	**38%**	$	197,395	29%
Stockholders' equity		**518,439**	**62%**		486,294	71%
Total capitalization, excluding short-term borrowings	**$**	**834,459**	**100%**	$	683,689	100%

(in thousands)	**December 31, 2018**			December 31, 2017		
Short-term debt	**$**	**294,458**	**26%**	$	250,969	26%
Long-term debt, including current maturities		**327,955**	**29%**		206,816	22%
Stockholders' equity		**518,439**	**45%**		486,294	52%
Total capitalization, including short-term borrowings	**$**	**1,140,852**	**100%**	$	944,079	100%

Included in the long-term debt balances at December 31, 2018, were capital lease obligations for Sandpiper and Sharp. Sandpiper maintains a capacity, supply and operating agreement ($620,000 of current maturities) that expires in May 2019. The capacity portion of this agreement is accounted for as a capital lease. Our Mid-Atlantic propane operations business unit has entered into an agreement to rent property in Anne Arundel County Maryland which it intends to purchase during the first quarter of 2019 ($690,000 of current maturities).

As of December 31, 2018, we had no restrictions on our cash balances. Chesapeake Utilities' Senior Notes and FPU's first mortgage bonds contain a restriction that limits the payment of dividends or other restricted payments in excess of certain pre-determined thresholds. As of December 31, 2018, $242.8 million of our consolidated net income and $118.2 million of FPU's net income were free of such restrictions.

Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. Including the funds expended specifically related to the impact of Hurricane Michael, our equity to total capitalization ratio, including short-term borrowings, was 45 percent as of December 31, 2018. Excluding the funds expended for Hurricane Michael restoration activities, our equity to total capitalization ratio, including short-term borrowings, would have been approximately 48 percent.

As described below under "Short-Term Borrowings," we have a Revolver with borrowing capacity of $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we also entered into long-term shelf agreements for the potential private placement of unsecured senior debt as further described below under the heading "Shelf Agreements."

We will seek to align, as much as feasible, any long-term debt or equity issuance(s) with the commencement of service and associated earnings for larger revenue generating capital projects and considering market conditions.

Shelf Agreements

We have entered into Shelf Agreements with Prudential, MetLife and NYL who are under no obligation to purchase any unsecured debt. The proceeds received from the issuances of these shelf notes was used to reduce borrowings under the Revolver and/or lines of credit and/or to fund capital expenditures. The Prudential Shelf Agreement totaling $150.0 million was entered in October 2015 and we issued $70.0 million of 3.25% unsecured debt in April 2017. The Prudential Shelf Agreement was then amended in September 2018 to increase the borrowing capacity back to $150.0 million of which Prudential accepted our request to purchase our unsecured debt of $100.0 million at an interest rate of 3.98% on or before August 20, 2019. The NYL Shelf Agreement totaling $100.0 million was entered in March 2017 and we issued unsecured debt totaling $100.0 million during 2018. The NYL Shelf Agreement was amended in November 2018 to add incremental borrowing capacity of $50.0 million. As of December 31, 2018, we had not requested that MetLife purchase unsecured senior debt under the MetLife Shelf Agreement. The following table summarizes our shelf agreements borrowing information at December 31, 2018:

Shelf Agreement *(in thousands)*	Total Borrowing Capacity	Less: Amount of Debt Issued	Less: Unfunded Commitments	Remaining Borrowing Capacity
Prudential Shelf Agreement	$ 220,000	$ (70,000)	$ (100,000)	$ 50,000
MetLife Shelf Agreement	150,000	—	—	150,000
NYL Shelf Agreement	150,000	(100,000)	—	50,000
Total	$ 520,000	$ (170,000)	$ (100,000)	$ 250,000

The Shelf Agreements or Shelf Notes set forth certain business covenants to which we are subject when any note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

Short-Term Borrowings

Our outstanding short-term borrowings at December 31, 2018 and 2017 were $294.5 million and $251.0 million, respectively, at weighted average interest rates of 3.44 percent and 2.42 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures program. As of December 31, 2018, we had five unsecured bank credit facilities with four financial institutions totaling $220.0 million in available credit. In addition, we have $150.0 million of additional short-term debt capacity available under the Revolver. The terms of the Revolver are described in further detail below. None of the unsecured bank lines of credit requires compensating balances.

The $150.0 million Revolver is available through October 8, 2020 and is subject to the terms and conditions set forth in the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures. Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25 percent or less. Interest is payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We have the right, under certain circumstances, to extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each Lender.

Our outstanding short-term borrowings at December 31, 2018 and 2017 included $4.4 million and $10.3 million, respectively, of book overdrafts, which are not actual borrowings under the credit facilities but, if presented, would be funded through the credit facilities and, therefore, were included in the short-term borrowings.

Our outstanding borrowings under these unsecured short-term credit facilities at December 31, 2018 and 2017 were $290.1 million and $240.7 million, respectively. Short-term borrowings were as follows during 2018, 2017 and 2016:

(in thousands)	**2018**	2017	2016
Average borrowings during the year	**$ 238,750**	$ 183,561	$ 172,808
Weighted average interest rate for the year	**2.93%**	2.03%	1.43%
Maximum month-end borrowings	**$ 290,103**	$ 240,671	$ 201,311

As of December 31, 2018, we had issued $7.0 million in letters of credit to various counterparties under the Revolver. Although the letters of credit are not included in the outstanding short-term borrowings and we do not anticipate they will be drawn upon by the counterparties, the letters of credit reduce the available borrowings under the Revolver.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the years ended December 31, 2018, 2017 and 2016:

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Net cash provided by (used in):			
Operating activities	**$ 146,778**	$ 110,089	$ 104,141
Investing activities	**(286,264)**	(186,895)	(170,037)
Financing activities	**139,961**	78,242	67,219
Net increase in cash and cash equivalents	**475**	1,436	1,323
Cash and cash equivalents—beginning of period	**5,614**	4,178	2,855
Cash and cash equivalents—end of period	**$ 6,089**	$ 5,614	$ 4,178

Cash Flows Provided by Operating Activities

Changes in our cash flows from operating activities are attributable primarily to changes in net income, adjusted for non-cash items such as depreciation and changes in deferred income taxes, and changes in working capital. Working capital requirements are determined by a variety of factors, including weather, the prices of natural gas, electricity and propane, the timing of customer collections, payments for purchases of natural gas, electricity and propane, and deferred fuel cost recoveries.

We normally generate a large portion of our annual net income and related increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas and propane delivered to customers during the peak heating season by our natural gas and propane operations and our natural gas supply, gathering and processing operation to customers during the peak heating season. In addition, our natural gas and propane inventories, which usually peak in the fall months, are largely drawn down in the heating season and provide a source of cash as the inventory is used to satisfy winter sales demand.

During 2018 and 2017, net cash provided by operating activities was $146.8 million and $110.1 million, respectively, resulting in an increase in cash flows of $36.7 million. Significant operating activities generating the cash flows change were as follows:

- Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities increased cash flows by $23.5 million, due primarily to the timing of the receipt of customer payments from increased revenue as well as the timing of payments to vendors.
- Net cash flows from changes in propane inventory, storage gas and other inventories increased by approximately $11.1 million due primarily to higher levels of our inventory during 2017.
- Changes in net prepaid expenses and other current assets, customer deposits and refunds decreased cash flows by $11.7 million due primarily to higher refund activity to customers associated with the impacts of the TCJA through the implementation of lower rates.
- Cash flows from changes in deferred income taxes resulted in an increase of $10.1 million due primarily to timing differences associated with depreciation from increased capital expenditures compared to the prior year, offset by $8.6 million in changes in income taxes payable as a result of the impacts of the TCJA.
- Changes in net regulatory assets and liabilities increased cash flows by $5.1 million, due primarily to the change in fuel costs collected through the various cost recovery mechanisms.

During 2017 and 2016, net cash provided by operating activities was $110.1 million and $104.1 million, respectively, resulting in an increase in cash flows of $6.0 million. Significant operating activities generating the cash flow change were as follows:

- Net income, adjusted for reconciling activities, decreased cash flows by $485,000. Key reconciling items included: the revaluation of deferred tax assets and liabilities of our unregulated businesses as a result of the implementation of the TCJA, which decreased our deferred tax expense by $14.3 million, higher non-cash adjustments for depreciation and amortization related to increased investing activities and realized losses on sales of assets.
- Net cash flows from changes in other inventories decreased by approximately $6.5 million, due primarily to purchases of additional pipes and other construction inventory as a result of the large expansion projects then underway.
- Changes in income taxes receivable increased cash flows by $5.6 million, due to higher tax refunds as a result of increased tax deductions associated with bonus depreciation.
- Changes in net regulatory assets and liabilities increased cash flows by $4.7 million, due primarily to the change in fuel costs collected through the various cost recovery mechanisms and GRIP.
- Changes in net accounts receivable, accrued revenue, accounts payable and accrued liabilities increased cash flows by $3.5 million, due primarily to higher revenues and the timing of customer payments and payments to vendors.
- Changes in net prepaid expenses and other current assets and customer deposits and refunds decreased cash flows by $2.2 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $286.3 million and $186.9 million during the year ended December 31, 2018 and 2017, respectively, resulting in a decrease in cash flows of $99.4 million. Key investing activities contributing to the cash flow change included:

- Cash paid for capital expenditures increased by $94.4 million due in part to the costs associated with restoring equipment and service to customers following Hurricane Michael in Florida.
- Net cash of $16.7 million was used to acquire operating assets of Ohl and Marlin CNG Services.

Net cash used in investing activities totaled $186.9 million and $170.0 million for 2017 and 2016, respectively, resulting in a decrease in cash flows of $16.9 million in 2017. Key investing activities contributing to the cash flow change included:

- Cash paid for capital expenditures increased by $5.4 million to $175.3 million for 2017.
- Net cash of $11.9 million was used to acquire assets in various transactions during 2017, including ARM, Chipola and Central Gas; there were no corresponding transactions in 2016.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities totaled $140.0 million for the year ended December 31, 2018, compared to net cash of $78.2 million provided by financing activities during the prior year resulted in an increase in cash flows of $61.7 million, primarily due to the following:

- Receipt of $154.8 million in net cash proceeds from the Revolver, the Term Note and the issuance of the NYL Shelf Notes (Series A) in May and November 2018, respectively, which increased cash flow by $85.0 million during the year ended December 31, 2018, compared to the prior year. For the year ended December 31, 2017, we received $69.8 million in net proceeds from the issuance of the Prudential Shelf Notes;

- Increased cash flows from lower repayments of short-term borrowing of $10.1 million under our line of credit arrangements in 2018;
- Decreased cash flows of $7.7 million as a result of changes in cash overdrafts in 2018;
- Higher repayment of long-term debt and capital lease obligations of $34.4 million during the year ended December 31, 2018, compared to $12.1 million in the prior year; and
- Cash dividend payments of $22.0 million in 2018 compared to $19.9 million for 2017.

Net cash provided by financing activities totaled $78.2 million and $67.2 million for 2017 and 2016, respectively. The increase in net cash provided by financing activities in 2017 resulted primarily from the following:

- $69.8 million in net cash proceeds from the issuance of the Prudential Shelf Notes in 2017, offset by the payment of $3.0 million in scheduled long-term debt principal and capital lease obligations payments.
- Net cash flows decreased by $57.4 million due to the absence of proceeds related to the issuance of common stock during the third quarter of 2016.
- Net borrowing of $39.3 million for 2017, compared to net borrowing of $32.5 million for 2016, increased cash flows by $6.8 million. Change in cash overdrafts decreased cash flows by $2.2 million.
- Cash dividend payments of $19.9 million in 2017 compared to $17.5 million for 2016.

CONTRACTUAL OBLIGATIONS

We have the following contractual obligations and other commercial commitments as of December 31, 2018:

	Payments Due by Period				
Contractual Obligations	**2019**	**2020-2021**	**2022-2023**	**After 2023**	**Total**
(in thousands)					
Long-term debt [(1)]	$ 10,626	$ 59,200	$ 45,700	$ 211,700	$ 327,226
Operating leases [(2)]	2,349	3,759	3,331	5,398	14,837
Capital leases [(2)]	1,310	—	—	—	1,310
Purchase obligations [(3)]					
Transmission capacity	32,276	53,062	39,197	127,634	252,169
Storage capacity	1,720	978	355	—	3,053
Commodities	107,713	18,255	—	—	125,968
Electric supply	16,835	2,675	2,727	1,385	23,622
Unfunded benefits [(4)]	597	692	635	1,421	3,345
Funded benefits [(5)]	2,823	—	—	5,188	8,011
Total Contractual Obligations	**$ 176,249**	**$ 138,621**	**$ 91,945**	**$ 352,726**	**$ 759,541**

(1) This represents principal payments on long-term debt. See *Item 8, Financial Statements and Supplementary Data,* Note 13*, Long-Term Debt*, for additional information. The expected interest payments on long-term debt are $12.9 million, $21.6 million, $17.5 million and $49.8 million, respectively, for the periods indicated above. Expected interest payments for all periods total $101.8 million.
(2) See *Item 8, Financial Statements and Supplementary Data,* Note 15*, Lease Obligations*, for additional information.
(3) See *Item 8, Financial Statements and Supplementary Data,* Note 21*, Other Commitments and Contingencies*, for additional information.
(4) We have recorded long-term liabilities of $3.3 million at December 31, 2018 for unfunded post-employment and post-retirement benefit plans. The amounts specified in the table are based on expected payments to current retirees and assume a retirement age of 62 for currently active employees. There are many factors that would cause actual payments to differ from these amounts, including early retirement, future health care costs that differ from past experience and discount rates implicit in calculations. See *Item 8, Financial Statements and Supplementary Data,* Note 17*, Employee Benefit Plan*s, for additional information on the plans.
(5) We have recorded long-term liabilities of $17.8 million at December 31, 2018 for two qualified, defined benefit pension plans. The assets funding these plans are in a separate trust and are not considered assets of ours or included in our balance sheets. The Contractual Obligations table above includes $1.3 million, reflecting the payments we expect to make to the trust funds in 2017. Additional contributions may be required in future years based on the actual return earned by the plan assets and other actuarial assumptions, such as the discount rate and long-term expected rate of return on plan assets. See *Item 8, Financial Statements and Supplementary Data,* Note 17*, Employee Benefit Plan*s, for further information on the plans. Additionally, the Contractual Obligations table above includes deferred compensation obligations totaling $6.7 million, funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the consolidated balance sheets. We assume a retirement age of 65 for purposes of distribution from this account.

OFF-BALANCE SHEET ARRANGEMENTS

We have issued corporate guarantees to certain vendors of our subsidiaries that provide for the payment of propane and natural gas purchases in the event of the subsidiary's default. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at December 31, 2018 was $76.5 million, with the guarantees expiring on various dates throughout 2019.

We have issued letters of credit totaling $7.0 million related to the electric transmission services for FPU's northwest electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, and to our current and previous primary insurance carrier with expiration dates extending through December 2019. There were no draws on these letters of credit as of December 31, 2018. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future. Additional information is presented in *Item 8, Financial Statements and Supplementary Data,* Note 21*, Other Commitments and Contingencies* in the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

We prepare our financial statements in accordance with GAAP. Application of these accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingencies during the reporting period. We base our estimates on historical experience and on various assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Since a significant portion of our businesses are regulated and the accounting methods used by these businesses must comply with the requirements of the regulatory bodies, the choices available are limited by these regulatory requirements. In the normal course of business, estimated amounts are subsequently adjusted to actual results that may differ from the estimates.

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with ASC Topic 980, *Regulated Operations*, and consequently, the accounting principles applied by our regulated energy businesses differ in certain respects from those applied by the unregulated businesses. Amounts are deferred as regulatory assets and liabilities when there is a probable expectation that they will be recovered in future revenues or refunded to customers as a result of the regulatory process. This is more fully described in Item 8*, Financial Statements and Supplementary Data,* Note 2*, Summary of Significant Accounting Policies,* in the consolidated financial statements. If we were required to terminate the application of ASC Topic 980, we would be required to recognize all such deferred amounts as a charge or a credit to earnings, net of applicable income taxes. Such an adjustment could have a material effect on our results of operations.

Valuation of Environmental Liabilities and Related Regulatory Assets

As more fully described in Item 8*, Financial Statements and Supplementary Data,* Note 20*, Environmental Commitments and Contingencies*, in the consolidated financial statements, we are currently participating in the investigation, assessment or remediation of seven former MGP sites for which we have sought or will seek regulatory approval to recover through rates the estimated costs of remediation and related activities. Amounts have been recorded as environmental liabilities based on estimates of future costs to remediate these sites, which are provided by independent consultants.

Derivative Instruments

We use derivative and non-derivative instruments to manage the risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. We continually monitor the use of these instruments to ensure compliance with our risk management policies and account for them in accordance with GAAP, such that every derivative instrument is recorded as either an asset or a liability measured at its fair value. It also requires that changes in the derivatives' fair value are recognized in the current period earnings unless specific hedge accounting criteria are met. If these instruments do not meet the definition of derivatives or are considered "normal purchases and normal sales," they are accounted for on an accrual basis of accounting.

Additionally, GAAP also requires us to classify the derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the fair value of the assets and liabilities and their placement within the fair value hierarchy.

We determined that certain propane put options, call options, swap agreements and natural gas futures contracts met the specific hedge accounting criteria. We also determined that most of our contracts for the purchase or sale of natural gas, electricity and propane either: (i) did not meet the definition of derivatives because they did not have a minimum purchase/sell requirement, or (ii) were considered "normal purchases and normal sales" because the contracts provided for the purchase or sale of natural gas, electricity or propane to be delivered in quantities that we expect to use or sell over a reasonable period of time in the normal course of business. Accordingly, these contracts were accounted for on an accrual basis of accounting.

Additional information about our derivative instruments is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 8, *Derivative Instruments,* in the Consolidated Financial Statements.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC of each state in which we operate. Customers' base rates may not be changed without formal approval by these PSCs. However, the PSCs authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. Eastern Shore's revenues are based on rates approved by the FERC. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to negotiated rates.

Peninsula Pipeline, our Florida intrastate pipeline subsidiary that is subject to regulation by the Florida PSC, has negotiated firm transportation service contracts with third-party customers and with certain affiliates.

For regulated deliveries of natural gas, propane and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class. A similar computation is made to accrue unbilled revenues for propane customers with meters, such as community gas system customers and natural gas marketing customers, whose billing cycles do not coincide with the accounting periods.

Our natural gas supply operation in Ohio recognizes revenues based on actual volumes of natural gas shipped, using contractual rates, which are based upon index prices that are published monthly.

Eight Flags records revenues based on the amount of electricity and steam generated and sold to its customers.

Each of our natural gas distribution operations in Delaware and Maryland, our bundled natural gas distribution service in Florida and our electric distribution operation in Florida has a fuel cost recovery mechanism. This mechanism provides a method of adjusting billing rates to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year.

We charge flexible rates to industrial interruptible customers on our natural gas distribution systems to compete with the price of alternative fuel that they can use. Neither we, nor any of our interruptible customers, are contractually obligated to deliver or receive natural gas on a firm service basis.

Allowance for Doubtful Accounts

An allowance for doubtful accounts is recorded against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect based upon our collections experience, the condition of the overall economy and our assessment of our customers' inability or reluctance to pay. If circumstances change, however, our estimate of the recoverability of accounts receivable may also change. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Goodwill and Other Intangible Assets

We test goodwill for impairment at least annually in December. The annual impairment testing for 2018 indicated no impairment of goodwill. Additional information is presented in Item 8, *Financial Statements and Supplementary Data,* Note 11, *Goodwill and Other Intangible Assets,* in the consolidated financial statements.

Other Assets Impairment Evaluations

We periodically evaluate whether events or circumstances have occurred which indicate that long-lived assets may not be recoverable. When events or circumstances indicate that an impairment is present, we record an impairment loss equal to the excess of the asset's carrying value over its fair value, if any.

Pension and Other Postretirement Benefits

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. The assumed discount rates and the expected returns on plan assets are the assumptions that generally have the most significant impact on the pension costs and liabilities. The assumed discount rates, the assumed health care cost trend rates and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. Additional information is presented in Item 8, *Financial Statements and Supplementary Data,* Note 17*, Employee Benefit Plans,* in the consolidated financial statements, including plan asset investment allocation, estimated future benefit payments, general descriptions of the plans, significant assumptions, the impact of certain changes in assumptions, and significant changes in estimates.

For 2018, actuarial assumptions include expected long-term rates of return on plan assets of 6.00 percent and 6.50 percent for Chesapeake Utilities' pension plan and FPU's pension plan, respectively, and discount rates of 3.50 percent and 3.75 percent for Chesapeake Utilities' and FPU's plans, respectively. The discount rate for each plan was determined by management considering high-quality corporate bond rates, such as the Prudential curve index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected lives of the plans and the availability of the lump-sum payment option. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately $20,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $20,000.

Actual changes in the fair value of plan assets and the differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension benefit costs that we ultimately recognize. A 0.25 percent change in the rate of return could change our annual pension cost by approximately $128,000 and would not have an impact on the postretirement and Chesapeake SERP because these plans are not funded.

Tax-Related Contingency

We account for uncertainty in income taxes in the consolidated financial statements only if it is more likely than not that an uncertain tax position is sustainable based on its technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the consolidated financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

We account for contingencies associated with taxes other than income when the likelihood of a loss is both probable and quantifiable. In assessing the likelihood of a loss, we do not consider the existence of current inquiries, or the likelihood of future inquiries, by tax authorities as a factor. Our assessment is based solely on our application of the appropriate statutes and the likelihood of a loss, assuming the proper inquiries are made by tax authorities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

INTEREST RATE RISK

Long-term debt is subject to potential losses based on changes in interest rates. Additional information about our long-term debt is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 13, *Long-term Debt,* in the consolidated financial statements.

COMMODITY PRICE RISK

Regulated Energy Segment

We have entered into agreements with various wholesale suppliers to purchase natural gas and electricity for resale to our customers. Our regulated energy distribution businesses that sell natural gas or electricity to end-use customers have fuel cost recovery mechanisms authorized by the PSCs that allow us to recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers. Therefore, our regulated energy distribution operations have limited commodity price risk exposure.

Unregulated Energy Segment

Our propane operations are exposed to commodity price risk as a result of the competitive nature of retail pricing offered to our customers. In order to mitigate this risk, we utilize propane storage activities and forward contracts for supply.

We can store up to approximately 7.1 million gallons of propane (including leased storage and rail cars) during the winter season to serve our customers. Decreases in wholesale propane prices may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate this risk, we have implemented a Risk Management Policy that allows our propane operation to enter into fair value hedges, cash flows hedges or other economic hedges of our inventory.

Aspire Energy is exposed to commodity price risk, primarily during the winter season, to the extent we are not successful in balancing our natural gas purchases and sales and have to secure natural gas from alternative sources at higher spot prices. In order to mitigate this risk, we procure firm capacity that meets our estimated volume requirements and we continue to seek out new producers to fulfill our natural gas purchase requirements.

PESCO is a party to natural gas swap and futures contracts, which provide us the right to purchase natural gas at a fixed price at future dates. Upon expiration, the contracts can be settled financially without taking delivery of natural gas, or PESCO can procure natural gas and deliver it to its customers. PESCO is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids and natural gas deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts.

The following table reflects the changes in the fair market value of financial derivatives contracts related to natural gas and propane purchases and sales from December 31, 2017 to December 31, 2018:

(in thousands)	**Balance at December 31, 2017**	**Increase (Decrease) in Fair Market Value**	**Less Amounts Settled**	**Balance at December 31, 2018**
PESCO	$ (6,153)	$ 16,674	$ (10,705)	**$ (184)**
Sharp	1,192	(3,376)	663	**(1,521)**
Total	$ (4,961)	$ 13,298	$ (10,042)	**$ (1,705)**

There were no changes in the methods of valuations during the year ended December 31, 2018.

The following is a summary of fair market value of financial derivatives as of December 31, 2018, by method of valuation and by maturity for each fiscal year period.

(in thousands)	**2019**	**2020**	**2021**	**2022**	**Total Fair Value**
Price based on ICE[1] PESCO	$ (2,075)	$ 1,817	$ 72	$ 2	$ (184)
Price based on Mont Belvieu - Sharp	(1,229)	(250)	(42)	—	(1,521)
Total	$ (3,304)	$ 1,567	$ 30	$ 2	$ (1,705)

[1] Intercontinental Exchange (an electronic trading platform)

WHOLESALE CREDIT RISK

The Risk Management Committee reviews credit risks associated with counterparties to commodity derivative contracts prior to such contracts being approved.

Additional information about our derivative instruments is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 8, *Derivative Instruments,* in the Consolidated Financial Statements.

INFLATION

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we periodically seek rate increases from regulatory commissions for our regulated operations and closely monitor the returns of our unregulated energy business operations. To compensate for fluctuations in propane gas prices, we adjust propane sales prices to the extent allowed by the market.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation

Opinions on the Consolidated Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation and Subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the years in the three-year period ended December 31, 2018, and the related notes and financial statement schedule listed in Item 15(a)2 (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework: (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework: (2013)* issued by COSO.

Basis for Opinion

The Company's management is responsible for these consolidated financial statements, 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 Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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/ Baker Tilly Virchow Krause, LLP

We have served as the Company's auditor since 2007.

Philadelphia, Pennsylvania
February 26, 2019

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Income

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands, except shares and per share data)			
Operating Revenues			
Regulated Energy	**$ 345,281**	$ 326,310	$ 305,689
Unregulated Energy	**420,617**	324,595	203,778
Other businesses and eliminations	**(48,409)**	(33,322)	(10,607)
Total operating revenues	**717,489**	617,583	498,860
Operating Expenses			
Regulated Energy cost of sales	**121,828**	118,769	109,609
Unregulated Energy and other cost of sales	**288,913**	219,145	128,434
Operations	**138,441**	125,994	115,684
Maintenance	**14,387**	12,701	12,391
Gain from a settlement	**(130)**	(130)	(130)
Depreciation and amortization	**40,802**	36,599	32,159
Other taxes	**18,628**	17,085	14,730
Total operating expenses	**622,869**	530,163	412,877
Operating Income	**94,620**	87,420	85,983
Other expense, net	**(615)**	(2,342)	(2,328)
Interest charges	**16,431**	12,645	10,639
Income Before Income Taxes	**77,574**	72,433	73,016
Income taxes	**20,994**	14,309	28,341
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Weighted Average Common Shares Outstanding:			
Basic	**16,369,616**	16,336,789	15,570,539
Diluted	**16,419,870**	16,383,352	15,613,091
Earnings Per Share of Common Stock:			
Basic	**$ 3.46**	$ 3.56	$ 2.87
Diluted	**$ 3.45**	$ 3.55	$ 2.86
Cash Dividends Declared Per Share of Common Stock	**$ 1.4350**	$ 1.2800	$ 1.2025

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Comprehensive Income

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Other Comprehensive Income (Loss), net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of $(22), $(31) and $(29), respectively	**(55)**	(46)	(48)
Net (loss)/gain, net of tax of $(49), $432, and $178, respectively	**(108)**	663	268
Cash Flow Hedges, net of tax:			
Unrealized (loss)/gain on commodity contract cash flow hedges, net of tax of $(555), $(8) and $496, respectively	**(1,371)**	(11)	742
Total Other Comprehensive Income (Loss)	**(1,534)**	606	962
Comprehensive Income	**$ 55,046**	$ 58,730	$ 45,637

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

Assets	As of December 31,	
	2018	2017
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	**$ 1,297,416**	$ 1,073,736
Unregulated Energy	**237,682**	210,682
Other businesses and eliminations	**34,585**	27,699
Total property, plant and equipment	**1,569,683**	1,312,117
Less: Accumulated depreciation and amortization	**(294,295)**	(270,599)
Plus: Construction work in progress	**108,584**	84,509
Net property, plant and equipment	**1,383,972**	1,126,027
Current Assets		
Cash and cash equivalents	**6,089**	5,614
Accounts receivable (less allowance for uncollectible accounts of $1,108 and $936, respectively)	**85,404**	77,223
Accrued revenue	**27,499**	22,279
Propane inventory, at average cost	**9,791**	8,324
Other inventory, at average cost	**7,127**	12,022
Regulatory assets	**4,796**	10,930
Storage gas prepayments	**6,603**	5,250
Income taxes receivable	**15,300**	14,778
Prepaid expenses	**10,079**	13,621
Derivative assets, at fair value	**13,165**	1,286
Other current assets	**5,684**	7,260
Total current assets	**191,537**	178,587
Deferred Charges and Other Assets		
Goodwill	**25,837**	19,604
Other intangible assets, net	**6,207**	4,686
Investments, at fair value	**6,711**	6,756
Regulatory assets	**72,422**	75,575
Receivables and other deferred charges	**6,985**	3,699
Total deferred charges and other assets	**118,162**	110,320
Total Assets	**$ 1,693,671**	$ 1,414,934

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

	As of December 31,	
Capitalization and Liabilities	**2018**	**2017**
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Preferred stock, par value $0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	**$ —**	$ —
Common stock, par value $0.4867 per share (authorized 50,000,000 shares)	**7,971**	7,955
Additional paid-in capital	**255,651**	253,470
Retained earnings	**261,530**	229,141
Accumulated other comprehensive loss	**(6,713)**	(4,272)
Deferred compensation obligation	**3,854**	3,395
Treasury stock	**(3,854)**	(3,395)
Total stockholders' equity	**518,439**	486,294
Long-term debt, net of current maturities	**316,020**	197,395
Total capitalization	**834,459**	683,689
Current Liabilities		
Current portion of long-term debt	**11,935**	9,421
Short-term borrowing	**294,458**	250,969
Accounts payable	**129,804**	74,688
Customer deposits and refunds	**34,155**	34,751
Accrued interest	**2,317**	1,742
Dividends payable	**6,060**	5,312
Accrued compensation	**13,923**	13,112
Regulatory liabilities	**7,883**	6,485
Derivative liabilities, at fair value	**14,871**	6,247
Other accrued liabilities	**12,828**	10,273
Total current liabilities	**528,234**	413,000
Deferred Credits and Other Liabilities		
Deferred income taxes	**156,820**	135,850
Regulatory liabilities	**135,039**	140,978
Environmental liabilities	**7,638**	8,263
Other pension and benefit costs	**28,513**	29,699
Deferred investment tax credits and other liabilities	**2,968**	3,455
Total deferred credits and other liabilities	**330,978**	318,245
Environmental and other commitments and contingencies (Note 20 and 21)		
Total Capitalization and Liabilities	**$ 1,693,671**	$ 1,414,934

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Operating Activities			
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	**40,802**	36,599	32,159
Depreciation and accretion included in operations expenses	**8,535**	8,122	7,334
Deferred income taxes, net	**21,226**	11,085	31,257
Realized loss on sale of assets/investments/commodity contracts	**5,497**	3,179	695
Unrealized loss (gain) on investments/commodity contracts	**429**	(1,001)	(385)
Employee benefits and compensation	**856**	1,577	1,887
Share-based compensation	**2,813**	2,490	2,367
Other, net	**—**	(750)	(79)
Changes in assets and liabilities:			
Accounts receivable and accrued revenue	**(16,311)**	(19,506)	(27,013)
Propane inventory, storage gas and other inventory	**2,107**	(9,036)	(2,531)
Regulatory assets/liabilities, net	**2,250**	(2,855)	(7,523)
Prepaid expenses and other current assets	**(7,421)**	(7,001)	(1,387)
Accounts payable and other accrued liabilities	**35,907**	15,596	19,599
Income taxes receivable (payable)	**(522)**	8,110	2,466
Customer deposits and refunds	**(596)**	5,513	2,065
Accrued compensation	**708**	2,488	358
Other assets and liabilities, net	**(6,082)**	(2,645)	(1,803)
Net cash provided by operating activities	**146,778**	110,089	104,141
Investing Activities			
Property, plant and equipment expenditures	**(269,767)**	(175,329)	(169,861)
Proceeds from sale of assets	**782**	708	174
Acquisitions, net of cash acquired	**(16,654)**	(11,945)	—
Environmental expenditures	**(625)**	(329)	(350)
Net cash used in investing activities	**(286,264)**	(186,895)	(170,037)
Financing Activities			
Common stock dividends	**(22,043)**	(19,928)	(17,482)
Issuance of stock for Dividend Reinvestment Plan	**(706)**	89	811
Proceeds from issuance of common stock, net of expenses	**—**	(10)	57,360
Tax withholding payments related to net settled stock compensation	**(1,210)**	(692)	(770)
Change in cash overdrafts due to outstanding checks	**(5,943)**	1,738	3,920
Net borrowing under line of credit agreements	**49,432**	39,338	32,526
Proceeds from issuance of long-term debt	**154,819**	69,807	—
Repayment of long-term debt and capital lease obligation	**(34,388)**	(12,100)	(9,146)
Net cash provided by financing activities	**139,961**	78,242	67,219
Net Increase in Cash and Cash Equivalents	**475**	1,436	1,323
Cash and Cash Equivalents — Beginning of Period	**5,614**	4,178	2,855
Cash and Cash Equivalents — End of Period	**$ 6,089**	$ 5,614	$ 4,178

Supplemental Cash Flow Disclosures (see Note 7)

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Stockholders' Equity

(in thousands, except shares and per share data)	Common Stock [1] Number of Shares[2]	Common Stock [1] Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2015	**15,270,659**	**$ 7,432**	**$ 190,311**	**$ 166,235**	**$ (5,840)**	**$ 1,883**	**$ (1,883)**	**$ 358,138**
Net Income	—	—	—	44,675	—	—	—	**44,675**
Other comprehensive loss	—	—	—	—	962	—	—	**962**
Dividends declared ($1.2025 per share)	—	—	—	(18,848)	—	—	—	**(18,848)**
Retirement savings plan and dividend reinvestment plan	36,253	17	2,225	—	—	—	—	**2,242**
Stock issuance [3]	960,488	467	56,893	—	—	—	—	**57,360**
Share-based compensation and tax benefit [4] [5]	36,099	19	1,538	—	—	—	—	**1,557**
Treasury stock activities[2]	—	—	—	—	—	533	(533)	**—**
Balance at December 31, 2016	**16,303,499**	**7,935**	**250,967**	**192,062**	**(4,878)**	**2,416**	**(2,416)**	**446,086**
Net Income	—	—	—	58,124	—	—	—	**58,124**
Other comprehensive income	—	—	—	—	606	—	—	**606**
Dividends declared ($1.2800 per share)	—	—	—	(21,045)	—	—	—	**(21,045)**
Retirement savings plan and dividend reinvestment plan	10,771	5	730	—	—	—	—	**735**
Stock issuance [3]	—	—	(10)	—	—	—	—	**(10)**
Share-based compensation and tax benefit [4] [5]	30,172	15	1,783	—	—	—	—	**1,798**
Treasury stock activities[2]	—	—	—	—	—	979	(979)	**—**
Balance at December 31, 2017	**16,344,442**	**7,955**	**253,470**	**229,141**	**(4,272)**	**3,395**	**(3,395)**	**486,294**
Net Income	—	—	—	56,580	—	—	—	**56,580**
Cumulative effect of the adoption of ASU 2014-09	—	—	—	(1,498)	—	—	—	**(1,498)**
Reclassification upon the adoption of ASU 2018-02	—	—	—	907	(907)	—	—	**—**
Other comprehensive income	—	—	—	—	(1,534)	—	—	**(1,534)**
Dividends declared ($1.4350 per share)	—	—	—	(23,600)	—	—	—	**(23,600)**
Dividend reinvestment plan	—	—	(3)	—	—	—	—	**(3)**
Share-based compensation and tax benefit [4] [5]	34,103	16	2,184	—	—	—	—	**2,200**
Treasury stock activities[2]	—	—	—	—	—	459	(459)	**—**
Balance at December 31, 2018	**16,378,545**	**$ 7,971**	**$ 255,651**	**$ 261,530**	**$ (6,713)**	**$ 3,854**	**$ (3,854)**	**$ 518,439**

[1] 2,000,000 shares of preferred stock at $0.01 par value per share have been authorized. No shares have been issued or are outstanding; accordingly, no information has been included in the Statements of Stockholders' Equity. Shares of preferred stock may be issued from time to time, by authorization of our Board of Directors and at their discretion.

[2] Includes 97,053, 90,961 and 76,745 shares at December 31, 2018, 2017 and 2016, respectively, held in a Rabbi Trust related to our Non-Qualified Deferred Compensation Plan.

[3] On September 22, 2016, we completed a public offering of 960,488 shares of our common stock at a price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 million.

[4] Includes amounts for shares issued for directors' compensation.

[5] The shares issued under the SICP are net of shares withheld for employee taxes. For 2018, 2017 and 2016, we withheld 10,436, 10,269 and 12,031 shares, respectively, for taxes.

The accompanying notes are an integral part of the financial statements.

1. Organization and Basis of Presentation

Chesapeake Utilities, incorporated in 1947 in Delaware, is a diversified energy company engaged in regulated and unregulated energy businesses.

Our regulated energy businesses consist of: (a) regulated natural gas distribution operations in central and southern Delaware, Maryland's eastern shore and Florida; (b) regulated natural gas transmission operations on the Delmarva Peninsula, in Pennsylvania and in Florida; and (c) regulated electric distribution operations serving customers in northeast and northwest Florida.

Our unregulated energy businesses primarily include: (a) propane operations in the Mid-Atlantic region and Florida; (b) our natural gas marketing operation providing natural gas supply directly to commercial and industrial customers in Florida, Delaware, Maryland, Pennsylvania, Ohio and other states; (c) our unregulated natural gas transmission/supply operation in central and eastern Ohio; (d) our CHP plant in Florida that generates electricity and steam; and (e) our newest subsidiary, based in Florida, that provides mobile compressed natural gas ("CNG") utility and pipeline solutions to commercial, industrial and other utility customers throughout the Southeast and Midwest portions of the country.

Our consolidated financial statements include the accounts of Chesapeake Utilities and its wholly-owned subsidiaries. We do not have any ownership interest in investments accounted for using the equity method or any interest in a variable interest entity. All intercompany accounts and transactions have been eliminated in consolidation. We have assessed and, if applicable, reported on subsequent events through the date of issuance of these consolidated financial statements.

We reclassified certain amounts in the consolidated statement of income for the years ended December 31, 2017 and 2016 to conform to the current year's presentation.

2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates in measuring assets and liabilities and related revenues and expenses. These estimates involve judgments about various future economic factors that are difficult to predict and are beyond our control; therefore, actual results could differ from these estimates. As additional information becomes available, or actual amounts are determined, recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost less accumulated depreciation or fair value, if impaired. Costs include direct labor, materials and third-party construction contractor costs, allowance for funds used during construction ("AFUDC"), and certain indirect costs related to equipment and employees engaged in construction. The costs of repairs and minor replacements are charged to expense as incurred, and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of property within the regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. Upon retirement or disposition of property owned by the unregulated businesses, the gain or loss, net of salvage value, is charged to income. A summary of property, plant and equipment by classification as of December 31, 2018 and 2017 is provided in the following table:

	As of December 31,	
(in thousands)	**2018**	**2017**
Property, plant and equipment		
Regulated Energy		
Natural gas distribution - Delmarva Peninsula and Florida	**$ 657,630**	$ 589,149
Natural gas transmission - Delmarva Peninsula, Pennsylvania and Florida	**537,654**	384,360
Electric distribution – Florida	**102,133**	100,227
Unregulated Energy		
Propane operations – Mid-Atlantic and Florida	**123,632**	108,177
Natural gas transmission – Ohio	**70,225**	66,037
Electricity and Steam generation – Florida	**35,239**	35,239
Mobile CNG utility and pipeline solutions	**7,240**	—
Other unregulated energy	**1,346**	1,229
Other	**34,584**	27,699
Total property, plant and equipment	**1,569,683**	**1,312,117**
Less: Accumulated depreciation and amortization	**(294,295)**	(270,599)
Plus: Construction work in progress	**108,584**	84,509
Net property, plant and equipment	**$ 1,383,972**	$ 1,126,027

Contributions or Advances in Aid of Construction

Customer contributions or advances in aid of construction reduce property, plant and equipment, unless the amounts are refundable to customers. Contributions or advances may be refundable to customers after a number of years based on the amount of revenues generated from the customers or the duration of the service provided to the customers. Refundable contributions or advances are recorded initially as liabilities. Non-refundable contributions reduce property, plant and equipment at the time of such determination. As of December 31, 2018, 2017 and 2016, the non-refundable contributions totaled $2.8 million, $2.1 million and $1.0 million, respectively.

AFUDC

Some of the additions to our regulated property, plant and equipment include AFUDC, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects. AFUDC is capitalized in the applicable rate base for ratemaking purposes when the completed projects are placed in service. During the year ended December 31, 2018, AFUDC totaled $1.9 million, which was reflected as a reduction of interest charges. During the years ended December 31, 2017 and 2016, AFUDC was not material.

Assets Used in Leases

Property, plant and equipment for the Florida natural gas transmission operation included $1.4 million of assets, at December 31, 2018 and 2017, consisting primarily of mains, measuring equipment and regulation station equipment used by Peninsula Pipeline to provide natural gas transmission service pursuant to a contract with a third party. This contract is accounted for as an operating lease due to the exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and generates $264,000 in annual revenue for a 20-year term. Accumulated depreciation for these assets totaled $720,000 and $652,000 at December 31, 2018 and 2017, respectively.

Capital Lease Assets

Property, plant and equipment include capital lease assets related to: (i) a lease arrangement entered into by our Delmarva Peninsula natural gas distribution operation associated with Sandpiper's capacity, supply and operating agreement and (ii) our Mid-Atlantic propane operation's lease arrangement for property in Anne Arundel County Maryland which it intends to purchase during the first quarter of 2019. Information regarding the impact of the capital leases in our financial statements is shown below. Additional information can be found in Note 21, *Other Commitments and Contingencies*.

(in thousands)	As of December 31, 2018		2017	
Fair value of asset at lease inception	**$**	**7,816**	$	7,126
Less: Accumulated amortization		**6,506**		5,056
Capital lease asset	**$**	**1,310**	$	2,070

(in thousands)	For the years ended December 31, 2018	2017	2016
Amortization included in fuel cost recovery mechanism	**$1,451**	$1,401	$1,353

Jointly-owned Pipeline

Property, plant and equipment for our Florida natural gas transmission operation also included $6.7 million of assets, at December 31, 2018 and 2017, which consist of the 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida, jointly owned with Peoples Gas. The amount included in property, plant and equipment represents Peninsula Pipeline's 45-percent ownership of this pipeline. Peninsula Pipeline's share of direct expenses for the jointly-owned pipeline are included in the operating expenses of the income statement. Accumulated depreciation for this pipeline totaled $1.4 million and $1.3 million, at December 31, 2018 and 2017, respectively.

Asset Impairment Evaluations

We periodically evaluate whether events or circumstances have occurred, which indicate that other long-lived assets may not be fully recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the asset, compared to the carrying value of the asset. When such events or circumstances are present, we record an impairment loss equal to the excess of the asset's carrying value over its fair value, if any.

In May 2016, we received $650,000 in cash pursuant to a settlement agreement with a vendor related to implementation of a customer billing system which is reflected as "Gain from a settlement" in the accompanying consolidated statements of income. The retention of this amount is contingent upon engaging this vendor to provide agreed-upon services through May 2020.

Depreciation and Accretion Included in Operations Expenses

We compute depreciation expense for our regulated operations by applying composite, annual rates, as approved by the respective regulatory bodies. The following table shows the average depreciation rates used for regulated operations during the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
Natural gas distribution – Delmarva Peninsula	**2.5%**	2.5%	2.5%
Natural gas distribution – Florida	**2.9%**	2.9%	2.9%
Natural gas transmission – Delmarva Peninsula	**2.7%**	2.8%	2.7%
Natural gas transmission – Florida	**2.3%**	3.5%	3.9%
Electric distribution – Florida	**3.4%**	3.4%	3.5%

For our unregulated operations, we compute depreciation expense on a straight-line basis over the following estimated useful lives of the assets:

Asset Description	Useful Life
Propane distribution mains	10-37 years
Propane bulk plants and tanks	10-40 years
Propane equipment, meters and meter installations	5-33 years
Measuring and regulating station equipment	5-37 years
Natural gas pipelines	45 years
Natural gas right of ways	Perpetual
CHP plant	30 years
Natural gas processing equipment	20-25 years
Office furniture and equipment	3-10 years
Transportation equipment	4-20 years
Structures and improvements	5-45 years
Other	Various

We report certain depreciation and accretion in operations expense, rather than as a depreciation and amortization expense, in the accompanying consolidated statements of income in accordance with industry practice and regulatory requirements. Depreciation and accretion included in operations expense consists of the accretion of the costs of removal for future retirements of utility assets, vehicle depreciation, computer software and hardware depreciation, and other minor amounts of depreciation expense. For the years ended December 31, 2018, 2017 and 2016, we reported $8.5 million, $8.1 million and $7.3 million, respectively, of depreciation and accretion in operations expenses.

Regulated Operations

We account for our regulated operations in accordance with ASC Topic 980, *Regulated Operations,* which includes accounting principles for companies whose rates are determined by independent third-party regulators. When setting rates, regulators often make decisions, the economics of which require companies to defer costs or revenues in different periods than may be appropriate for unregulated enterprises. When this situation occurs, a regulated company defers the associated costs as regulatory assets on the balance sheet and records them as expense on the income statement as it collects revenues. Further, regulators can also impose liabilities upon a regulated company, for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future, as regulatory liabilities. If we were required to terminate the application of these regulatory provisions to our regulated operations, all such deferred amounts would be recognized in the statement of income at that time, which could have a material impact on our financial position, results of operations and cash flows.

We monitor our regulatory and competitive environments to determine whether the recovery of our regulatory assets continues to be probable. If we determined that recovery of these assets is no longer probable, we would write off the assets against earnings. We believe that the provisions of ASC Topic 980, *Regulated Operations,* continue to apply to our regulated operations and that the recovery of our regulatory assets is probable.

Revenue Recognition

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC in each state in which they operate. Eastern Shore's revenues are based on rates approved by the FERC. Customers' base rates may not be changed without formal approval by these commissions. The PSCs, however, have authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to FERC-approved maximum rates.

For regulated deliveries of natural gas and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class.

All of our regulated natural gas and electric distribution operations have fuel cost recovery mechanisms, except for two utilities that provide only unbundled delivery service (Chesapeake Utilities' Central Florida Gas division and FPU's Indiantown division). These mechanisms allow us to adjust billing rates, without further regulatory approvals, to reflect changes in the cost of purchased fuel. Differences between the cost of fuel purchased and delivered are deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year.

We charge flexible rates to our natural gas distribution industrial interruptible customers who can use alternative fuels. Interruptible service imposes no contractual obligation to deliver or receive natural gas on a firm service basis.

For the unregulated propane operation business, we record revenue in the period the products are delivered and/or services are rendered for bulk delivery customers without meters. For propane customers with meters and natural gas marketing customers whose billing cycles do not coincide with our accounting periods, we accrue unbilled revenue for product delivered but not yet billed and bill customers at the end of an accounting period, as we do in our regulated businesses.

Our Ohio natural gas transmission/supply operation recognizes revenues based on actual volumes of natural gas shipped using contractual rates based upon index prices that are published monthly.

Our natural gas marketing operation recognizes revenue based on the volume of natural gas delivered to its customers.

Eight Flags records revenues based on the amount of electricity and steam generated and sold to its customers.

We report revenue taxes, such as gross receipts taxes, franchise taxes, and sales taxes, on a net basis.

Cost of Sales

Cost of sales includes the direct costs attributable to the products sold or services provided to our customers. These costs include primarily the variable commodity cost of natural gas, electricity and propane, costs of pipeline capacity needed to transport and store natural gas, transmission costs for electricity, costs to gather and process natural gas, costs to transport propane to/from our storage facilities or our mobile CNG equipment to customer locations, and steam and electricity generation costs. Depreciation expense is not included in cost of sales.

Operations and Maintenance Expenses

Operations and maintenance expenses include operations and maintenance salaries and benefits, materials and supplies, usage of vehicles, tools and equipment, payments to contractors, utility plant maintenance, customer service, professional fees and other outside services, insurance expense, minor amounts of depreciation, accretion of removal costs for future retirements of utility assets and other administrative expenses.

Cash and Cash Equivalents

Our policy is to invest cash in excess of operating requirements in overnight income-producing accounts. Such amounts are stated at cost, which approximates fair value. Investments with an original maturity of three months or less when purchased are considered cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable consist primarily of amounts due for sales of natural gas, electricity and propane and transportation and distribution services to customers. An allowance for doubtful accounts is recorded against amounts due based upon our collections experiences and an assessment of our customers' inability or reluctance to pay. If circumstances change, our estimates of recoverable accounts receivable may also change. Circumstances which could affect such estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off when they are deemed to be uncollectible.

Inventories

We use the average cost method to value propane, materials and supplies, and other merchandise inventory. If market prices drop below cost, inventory balances that are subject to price risk are adjusted to their net realizable value. There was no lower-of-cost-or-net realizable value adjustment during 2018, 2017 or 2016.

Goodwill and Other Intangible Assets

Goodwill is not amortized but is tested for impairment at least annually, or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its implied fair value. The testing of goodwill for 2018, 2017 and 2016 indicated no goodwill impairment.

Other intangible assets are amortized on a straight-line basis over their estimated economic useful lives.

Other Deferred Charges

Other deferred charges include primarily issuance costs associated with short-term borrowings. These charges are amortized over the life of the related short-term debt borrowings.

Asset Removal Cost

As authorized by the appropriate regulatory body (state PSC or FERC), we accrue future asset removal costs associated with utility property, plant and equipment even if a legal obligation does not exist. Such accruals are provided for through depreciation expense and are recorded with corresponding credits to regulatory liabilities or assets. When we retire depreciable utility plant and equipment, we charge the associated original costs to accumulated depreciation and amortization, and any related removal costs incurred are charged to regulatory liabilities or assets. The difference between removal costs recognized in depreciation rates and the accretion and depreciation expense recognized for financial reporting purposes is a timing difference between recovery of these costs in rates and their recognition for financial reporting purposes. Accordingly, these differences are deferred as regulatory liabilities or assets. In the rate setting process, the regulatory liability or asset is excluded from the rate base upon which those utilities have the opportunity to earn their allowed rates of return. The costs associated with our asset retirement obligations are either currently being recovered in rates or are probable of recovery in future rates.

Pension and Other Postretirement Plans

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates, including the fair value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. We review annually the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities with the assistance of third-party actuarial firms. The assumed discount rates, expected returns on plan assets and the mortality assumption are the factors that generally have the most significant impact on our pension costs and liabilities. The assumed discount rates, health care cost trend rates and rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rates are utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When estimating our discount rates, we consider high-quality corporate bond rates, such as the Prudential curve index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected life of each of our plans and their respective payment options.

The expected long-term rates of return on assets are utilized in calculating the expected returns on the plan assets component of our annual pension plan costs. We estimate the expected returns on plan assets of each of our plans by evaluating expected bond returns, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rates of return on assets.

We estimate the health care cost trend rates used in determining our postretirement net expense based upon actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual reviews of participant census information as of the measurement date.

The mortality assumption used for our pension and postretirement plans reviewed periodically and is based on the actuarial table that best reflects of the expected mortality of the plan participants.

Income Taxes, Investment Tax Credit Adjustments and Tax-Related Contingency

Deferred tax assets and liabilities are recorded for the income tax effect of temporary differences between the financial statement basis and tax basis of assets and liabilities and are measured using the enacted income tax rates in effect in the years in which the differences are expected to reverse. Deferred tax assets are recorded net of any valuation allowance when it is more likely than not that such income tax benefits will be realized. Investment tax credits on utility property have been deferred and are allocated to income ratably over the lives of the subject property.

We account for uncertainty in income taxes in our consolidated financial statements only if it is more likely than not that an uncertain tax position is sustainable based on technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the consolidated financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

We account for contingencies associated with taxes other than income when the likelihood of a loss is both probable and estimable. In assessing the likelihood of a loss, we do not consider the existence of current inquiries, or the likelihood of future inquiries, by tax authorities as a factor. Our assessment is based solely on our application of the appropriate statutes and the likelihood of a loss, assuming the proper inquiries are made by tax authorities.

Financial Instruments

Our propane operations enter into derivative transactions, such as swaps, put options and call options in order to mitigate the impact of wholesale price fluctuations on inventory valuation and future purchase commitments. Our natural gas marketing operation enters into natural gas futures and swap contracts to mitigate any price risk associated with the purchase and/or sale of natural gas to specific customers. These transactions may be designated as fair value hedges or cash flow hedges, if they meet all of the accounting requirements pursuant to ASC Topic 815, *Derivatives and Hedging,* and we elect to designate the instruments as hedges. If designated as a fair value hedge, the value of the hedging instrument, such as a swap, future, or put option, is recorded at fair value, with the effective portion of the gain or loss of the hedging instrument effectively reducing or increasing the value of the hedged item. If designated as a cash flow hedge, the value of the hedging instrument, such as a swap, call option or natural gas futures contract, is recorded at fair value with the effective portion of the gain or loss of the hedging instrument being recorded in comprehensive income. The ineffective portion of the gain or loss of a hedge is recorded in earnings. If the instrument is not designated as a fair value or cash flow hedge, or it does not meet the accounting requirements of a hedge under ASC Topic 815, Derivatives and Hedging, it is recorded at fair value with all gains or losses being recorded directly in earnings.

Our natural gas, electric and propane operations and natural gas marketing operations enter into agreements with suppliers to purchase natural gas, electricity, and propane for resale to our respective customers. Purchases under these contracts, as well as distribution and marketing operations sales agreements with counterparties or customers, either do not meet the definition of a derivative, or qualify for "normal purchases and sales" treatment under ASC Topic 815 *Derivatives and Hedging*, and are accounted for on an accrual basis.

Recently Adopted Accounting Standards

Revenue from Contracts with Customers (ASC 606) - On January 1, 2018, we adopted ASU 2014-09, *Revenue from Contracts with Customers,* and all the related amendments using the modified retrospective method. We recognized the cumulative effect of initially applying the new revenue standard to all of our contracts as an adjustment to the beginning balance of retained earnings. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The impact of adoption of the new revenue standard was immaterial to our net income.

This standard required entities to recognize revenue when control of the promised goods or services is transferred to customers at an amount that reflects the consideration that the entity expects to receive in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. See Note 5, *Revenue Recognition,* for additional information.

The following highlights the impact of the adoption of ASC 606 on our income statement for the year ended December 31, 2018 and consolidated balance sheet as of December 31, 2018:

	Year Ended December 31, 2018		
Income statement	**As Reported**	**Without Adoption of ASC 606**	**Effect of Change Higher (Lower)**
(in thousands)			
Regulated Energy operating revenues	$ 345,281	$ 346,289	$ (1,008)
Regulated Energy cost of sales	121,828	122,463	(635)
Depreciation and amortization	40,802	40,767	35
Income before income taxes	77,574	77,981	(407)
Income taxes	20,994	21,106	(112)
Net income	56,580	56,875	(295)

Balance sheet	As of December 31, 2018		
	As Reported	Without Adoption of ASC 606	Effect of Change Higher (Lower)
(in thousands)			
Assets			
Accrued revenue	$ 27,499	$ 29,461	$ (1,962)
Long-term receivables and other deferred charges	$ 6,985	$ 6,816	$ 169
Capitalization			
Retained earnings	$ 261,530	$ 263,323	$ (1,793)

The primary impact of the adoption of ASC 606 on our income statement was the delayed recognition of approximately $407,000 in operating income during the year ended December 31, 2018, to future years, and a cumulative adjustment that decreased retained earnings and other assets by $1.8 million at December 31, 2018, associated with a long-term firm transmission contract with an industrial customer.

Compensation-Retirement Benefits (ASC 715) - In March 2017, the FASB issued ASU 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost.* Under this guidance, employers are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit costs are required to be presented in the income statement separately from the service cost component and should not be included in operating expenses. We adopted ASU 2017-07 on January 1, 2018 and applied the changes in the other components of net benefit costs, retrospectively. As our plans have been frozen for some time, there is no service cost component. The components of net benefit costs have been reclassified to other expense. Aside from changes in presentation, implementation of this standard did not have a material impact on our financial position or results of operations.

Statement of Cash Flows (ASC 230) - In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments*, which clarifies how certain transactions are classified in the statement of cash flows. We adopted ASU 2016-15 on January 1, 2018. Implementation of this new standard did not have a material impact on our consolidated statement of cash flows.

Compensation - Stock Compensation (ASC 718) - In May 2017, the FASB issued ASU 2017-09, *Scope of Modification Accounting,* to clarify when to account for a change in the terms or conditions of a share-based payment award as a modification. Under this guidance, modification accounting is required only if the fair value, the vesting conditions or the award classification (equity or liability) change because of a change in the terms or conditions of the award. We adopted ASU 2017-09, prospectively, on January 1, 2018. Implementation of this new standard did not have a material impact on our financial position or results of operations.

Income Statement - Reporting Comprehensive Income (ASC 220) - In February 2018, the FASB issued ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA. We adopted ASU 2018-02 on January 1, 2018, and reclassified stranded tax effects from accumulated other comprehensive loss related to our employee benefit plans and commodity contract cash flows hedges. Implementation of this new standard did not have a material impact on our financial position and results of operations. See Note 16, *Stockholders' Equity,* for additional information.

Derivatives and Hedging (ASC 815) - In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, to better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. ASU 2017-12 expands the risks that can be designated as hedged risks in cash flow hedges to include cash flow variability from contractually specified components of forecasted purchases or sales of non-financial assets. ASU 2017-12 requires the entire change in fair value of a hedging instrument that is included in the assessment of hedge effectiveness to be presented in the same income statement line that is used to present the earnings effects of the hedged item for fair value hedges and in other comprehensive income for cash flow hedges. ASU 2017-12 requires a tabular presentation of the income statement effect of fair value and cash flow hedges and eliminates the requirement to disclose the ineffective portion of the change in fair value of hedging instruments. We adopted ASU 2017-12, effective July 1, 2018, with no material impact on our financial statements. See Note 8, *Derivative Instruments,* for additional information with respect to the disclosures required by ASU 2017-12.

Compensation - Retirement Benefits - Defined Benefit Plans - General (ASC 715-20) - In August 2018, the FASB issued ASU 2018-14, *Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans*, which removes, clarifies and adds certain disclosure requirements in ASC 715-20 related to defined benefit pension and other postretirement plans. ASU

2018-14 will be effective for our annual and interim financial statements, on a retrospective basis, beginning January 1, 2021, although early adoption is permitted. We early adopted and updated our disclosures during the annual period ended December 31, 2018. Since the guidance impacted disclosures only, there was no impact on our financial position or results of operations.

Recent Accounting Standards Yet to be Adopted

Leases (ASC 842) - In February 2016, the FASB issued ASU 2016-02, *Leases,* which requires lessees to recognize leases on the balance sheet and disclose key information about leasing arrangements. The standard establishes a right of use ("ROU") model that requires a lessee to recognize a ROU asset and lease liability for all leases with a term greater than 12 months. The update also expands the required quantitative and qualitative disclosures surrounding leases. ASC 842 was subsequently amended by ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*; ASU No. 2018-10, *Codification Improvements to Topic 842, Lease*s; and ASU No. 2018-11, *Targeted Improvements*. ASU 2016-02 will be effective for our annual and interim financial statements, beginning January 1, 2019, although early adoption is permitted. We expect to adopt ASU 2016-02 effective January 1, 2019, and use the modified retrospective transition approach to all existing leases.

The new standard permits companies to elect several practical expedients. We expect to elect: (1) the ‘package of practical expedients,’ pursuant to which we do not need to reassess our prior conclusions about lease identification, lease classification and initial direct costs and (2) the ‘use-of-hindsight’ practical expedient, which allows us to use hindsight in assessing impairment of our existing land easements. We also intend to aggregate all non-lease components with the respective lease components.

The most significant effect of ASC 842 will be recognition of ROU assets and lease liabilities on our balance sheet for our operating leases and providing significant new disclosures about our leasing activities. We currently expect that upon adoption, we will recognize lease liabilities ranging from $11.0 to $13.0 million, with corresponding ROU of the same amount based on the present value of the remaining minimum rental payments for existing operating leases.

Intangibles-Goodwill (ASC 350) - In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment*, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. ASU 2017-04 will be effective for our annual and interim financial statements beginning January 1, 2020, although early adoption is permitted. The amendments included in this ASU are to be applied prospectively. We believe that implementation of this new standard will not have a material impact on our financial position or results of operations.

Compensation - Stock Compensation (ASC 718) - In June 2018, the FASB issued ASU 2018-07, *Improvements to Nonemployee Share-Based Payment Accounting*, which expands the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees. ASU 2018-07 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. We believe that implementation of this new standard will not have a material impact on our financial position or results of operations.

Fair Value Measurement (ASC 820) - In August 2018, the FASB issued ASU 2018-13, *Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*, which removes, modifies and adds certain disclosure requirements on fair value measurements in ASC 820. ASU 2018-13 will be effective for our annual and interim financial statements beginning January 1, 2020. Since the changes only impact disclosures, there will be no financial impact.

3. Earnings Per Share

The following table presents the calculation of our basic and diluted earnings per share for the years ended December 31:

	For the Year Ended December 31,		
(in thousands, except shares and per share data)	**2018**	**2017**	**2016**
Calculation of Basic Earnings Per Share:			
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Weighted average shares outstanding	**16,369,616**	16,336,789	15,570,539
Basic Earnings Per Share	**$ 3.46**	$ 3.56	$ 2.87
Calculation of Diluted Earnings Per Share:			
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Reconciliation of Denominator:			
Weighted average shares outstanding — Basic	**16,369,616**	16,336,789	15,570,539
Effect of dilutive securities — Share-based compensation	**50,254**	46,563	42,552
Adjusted denominator — Diluted	**16,419,870**	16,383,352	15,613,091
Diluted Earnings Per Share	**$ 3.45**	$ 3.55	$ 2.86

4. Acquisitions

Acquisitions in 2018

Marlin Gas Services and Ohl Fuel Oil Acquisitions

In December 2018, Marlin Gas Services, LLC (“Marlin Gas Services”), our newly created subsidiary, acquired certain operating assets of Marlin Gas Transport, Inc. (“Marlin Gas Transport”), a supplier of mobile compressed natural gas utility and pipeline solutions. The acquisition will enable Chesapeake Utilities to offer solutions to address supply interruption scenarios and tailor other alternatives where pipeline supplies are not available or cannot meet customer requirements.

In December 2018, Sharp acquired certain propane operating assets and customers of R. F. Ohl Fuel Oil, Inc. ("Ohl"), which provided propane distribution service to approximately 2,500 residential and commercial customers in Pennsylvania.

We accounted for the purchases of the operating assets of Marlin Gas Transport and Ohl, which totaled approximately $18.4 million, as business combinations within our Unregulated Energy segment. Goodwill of $4.8 million, related to the Marlin Gas Transport acquisition, and $1.5 million, associated with the Ohl acquisition, were initially recorded at the close of these transactions. The amounts recorded in conjunction with these acquisitions are preliminary and subject to adjustment based on additional valuations performed during the measurement period. Due to the timing of these acquisitions, the revenue and net income from these acquisitions in 2018 were immaterial.

Acquisitions in 2017

ARM, Chipola and Central Gas Acquisitions

In August 2017, PESCO acquired certain natural gas marketing assets of ARM Energy Management, LLC ("ARM"). The acquired assets complemented PESCO’s existing asset portfolio and expanded our regional footprint and retail demand in a market where we had existing pipeline capacity and wholesale liquidity. We accounted for the purchase of these assets as a business combination and initially recorded goodwill of $4.3 million within our Unregulated Energy segment. In connection with the acquisition, we initially recorded a contingent consideration liability of $2.5 million, based on a projection that the acquired business would achieve a gross margin target in 2018. During the second quarter of 2018, we identified certain known information as of the acquisition date that was not considered in our original analysis and would have resulted in no contingent consideration liability being initially recorded. Therefore, we reversed the originally-recorded contingent liability and reduced goodwill by $2.5 million. We similarly revised the consolidated balance sheet as of December 31, 2017. These revisions are considered immaterial to our consolidated financial statements. Based on actual gross margin results in 2018, we were not required to make additional payments under the contingent consideration provisions of the purchase agreement.

In August and December of 2017, Flo-gas acquired certain operating assets of Chipola Propane Gas Company ("Chipola") and Central Gas Company of Okeechobee, Incorporated ("Central Gas"), adding approximately 1,125 residential and commercial propane delivery service customers in Florida.

The acquisition accounting amounts recorded in conjunction with the above transactions are final. The revenue and net income from these acquisitions included in our consolidated statements of income were not material.

5. Revenue Recognition

We recognize revenue when our performance obligations under contracts with customers have been satisfied, which generally occurs when our businesses have delivered or transported natural gas, electricity or propane to customers. We exclude sales taxes and other similar taxes from the transaction price. Typically, our customers pay for the goods and/or services we provide in the month following the satisfaction of our performance obligation.

The following table displays our revenue by major source based on product and service type for the twelve months ended December 31, 2018:

(in thousands)	Regulated Energy	Unregulated Energy	Other and Eliminations	Total
Energy distribution				
Delaware natural gas division	$ 70,338	$ —	$ —	$ 70,338
Florida natural gas division	25,341	—	—	25,341
FPU electric distribution	79,803	—	—	79,803
FPU natural gas distribution	81,118	—	—	81,118
Maryland natural gas division	24,172	—	—	24,172
Sandpiper natural gas/propane operations	22,088	—	—	22,088
Total energy distribution	302,860	—	—	302,860
Energy transmission				
Aspire Energy	—	35,407	—	35,407
Eastern Shore	64,248	—	—	64,248
Peninsula Pipeline	11,927	—	—	11,927
Total energy transmission	76,175	35,407	—	111,582
Energy generation				
Eight Flags	—	17,302	—	17,302
Propane operations				
Mid-Atlantic propane operations	—	102,321	—	102,321
Florida propane operations	—	21,282	—	21,282
Total propane operations	—	123,603	—	123,603
Energy services				
Marlin Gas Services	—	121	—	121
PESCO - Natural Gas Marketing	—	258,713	—	258,713
	—	258,834	—	258,834
Other and eliminations				
Eliminations	(33,754)	(16,486)	(49,062)	(99,302)
Other	—	1,957	653	2,610
Total other and eliminations	(33,754)	(14,529)	(48,409)	(96,692)
Total operating revenues [(1)]	**$ 345,281**	**$ 420,617**	**$ (48,409)**	**$ 717,489**

[(1)] Includes other revenue (revenues from sources other than contracts with customers) of $236,000 and $334,000 for our Regulated and Unregulated Energy segments, respectively. The sources of other revenues include revenue from alternative revenue programs related to revenue normalization for Maryland division and Sandpiper and late fees.

Regulated Energy Segment

The businesses within our Regulated Energy segment are regulated utilities whose operations and customer contracts are subject to rates approved by the respective state PSC or the FERC.

Our energy distribution operations deliver natural gas or electricity to customers, and we bill the customers for both the delivery of natural gas or electricity and the related commodity, where applicable. In most jurisdictions, our customers are also required to purchase the commodity from us, although certain customers in some jurisdictions may purchase the commodity from a third-party retailer (in which case we provide delivery service only). We consider the delivery of natural gas or electricity and/or the related commodity sale as one performance obligation because the commodity and its delivery are highly interrelated with two-way dependency on one another. Our performance obligation is satisfied over time as natural gas or electricity is delivered and consumed by the customer. We recognize revenues based on monthly meter readings, which are based on the quantity of natural gas or electricity used and the approved rates. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period, to the extent that billing and delivery do not coincide.

Revenues for Eastern Shore are based on rates approved by the FERC. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to the FERC-approved maximum rates. Eastern Shore's services can be firm or interruptible. Firm services are offered on a guaranteed basis and are available at all times unless prevented by force majeure or other permitted curtailments. Interruptible customers receive service only when there is available capacity or supply. Our performance obligation is satisfied over time as we deliver natural gas to the customers' locations. We recognize revenues based on capacity used or reserved and the fixed monthly charge.

Peninsula Pipeline is engaged in natural gas intrastate transmission to third-party customers and certain affiliates in the State of Florida. Our performance obligation is satisfied over time as the natural gas is transported to customers. We recognize revenue based on rates approved by the Florida PSC and the capacity used or reserved. We accrue unbilled revenues for transportation services provided and not yet billed at the end of an accounting period.

Unregulated Energy Segment

Revenues generated from the Unregulated Energy segment are not subject to any federal, state, or local pricing regulations. Aspire Energy primarily sources gas from hundreds of conventional producers and performs gathering and processing functions to maintain the quality and reliability of its gas for its wholesale customers. Aspire Energy's performance obligation is satisfied over time as natural gas is delivered to its customers. Aspire Energy recognizes revenue based on the deliveries of natural gas at contractually agreed upon rates (which are based upon an established monthly index price and a monthly operating fee, as applicable). For natural gas customers, we accrue unbilled revenues for natural gas that has been delivered, but not yet billed, at the end of an accounting period, to the extent that billing and delivery do not coincide with the end of the accounting period.

Eight Flags' CHP plant, which is located on land leased from a customer, produces three sources of energy: electricity, steam and heated water. Rayonier purchases the steam (unfired and fired) and heated water, which are used in the customer’s production facility. Our electric distribution operation purchases the electricity generated by the CHP plant for distribution to its customers. Eight Flags' performance obligation is satisfied over time as deliveries of heated water, steam and electricity occur. Eight Flags recognizes revenues over time based on the amount of heated water, steam and electricity generated and delivered to its customers.

For our propane operations, we recognize revenue based upon customer type and service offered. Generally, for propane bulk delivery customers (customers without meters) and wholesale sales, our performance obligation is satisfied when we deliver propane to the customers' locations (point-in-time basis). We recognize revenue from these customers based on the number of gallons delivered and the price per gallon at the point-in-time of delivery. For our propane delivery customers with meters, we satisfy our performance obligation over time when we deliver propane to customers. We recognize revenue over time based on the amount of propane consumed and the applicable price per unit. For propane delivery metered customers, we accrue unbilled revenues for propane that has been delivered, but not yet billed, at the end of an accounting period, to the extent that billing and delivery do not coincide with the end of the accounting period.

PESCO provides natural gas supply and asset management services to customers (including affiliates of Chesapeake Utilities) located primarily in Florida, the Delmarva Peninsula, and the Appalachian Basin. PESCO's performance obligation is satisfied over time as natural gas is delivered to its customers. PESCO recognizes revenue over time based on monthly customer meter readings. We accrue unbilled revenues for natural gas that has been delivered, but not yet billed, at the end of an accounting period.

Contract balances

The timing of revenue recognition, customer billings and cash collections results in trade receivables, unbilled receivables (contract assets), and customer advances (contract liabilities) in our consolidated balance sheets. The balances of our trade receivables, contract assets, and contract liabilities as of December 31, 2018 and 2017 were as follows:

	Trade Receivables		Contract Assets (Non-current)		Contract Liabilities (Current)	
(in thousands)						
Balance at 12/31/2017	$	74,962	$	1,270	$	407
Balance at 12/31/2018		**83,214**		**2,614**		**480**
Increase (decrease)	$	8,252	$	1,344	$	73

Our trade receivables are included in accounts receivable in the consolidated balance sheets. Our non-current contract assets are included in receivables and other deferred charges in the consolidated balance sheet and relate to operations and maintenance costs incurred by Eight Flags that have not yet been recovered through rates for the sale of electricity to our electric distribution operation pursuant to a long-term service agreement.

At times, we receive advances or deposits from our customers before we satisfy our performance obligation, resulting in contract liabilities. At December 31, 2018 and 2017, we had a contract liability of $480,000 and $407,000, respectively, which was included in other accrued liabilities in the consolidated balance sheet, and which relates to non-refundable prepaid fixed fees for our Mid-Atlantic propane operation's retail offerings. Our performance obligation is satisfied over the term of the respective retail offering plan on a ratable basis. For the twelve months ended December 31, 2018, we recognized revenue of $697,000.

Remaining performance obligations

Our businesses have long-term fixed fee contracts with customers in which revenues are recognized as performance obligations are satisfied over the contract term. Revenue for these businesses for the remaining performance obligations at December 31, 2018 are expected to be recognized as follows:

(in thousands)	2019	2020	2021	2022	2023	2024 and thereafter
Eastern Shore and Peninsula Pipeline	$38,505	$36,768	$33,510	$26,566	$21,146	$ 212,620
Natural gas distribution operations	4,109	3,586	3,358	3,320	2,924	30,826
PESCO - Natural Gas Marketing	8,886	4,702	1,728	23	—	—
FPU electric distribution	297	297	297	109	—	—
Total revenue contracts with remaining performance obligations	$51,797	$45,353	$38,893	$30,018	$24,070	$ 243,446

Practical expedients

For our businesses with agreements that contain variable consideration, we use the invoice practical expedient method. We determined that the amounts invoiced to customers correspond directly with the value to our customers and our performance to date.

6. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance.

Our operations are comprised of two reportable segments:

- *Regulated Energy*. Includes energy distribution and transmission services (natural gas distribution, natural gas transmission and electric distribution operations). All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.

- *Unregulated Energy.* Includes energy transmission, energy generation (the operations of our Eight Flags' CHP plant), propane operations, the new mobile CNG utility and pipeline solutions subsidiary, and other energy services (natural gas marketing and related services). These operations are unregulated as to their rates and services. Through March 2017, this segment also included the operations of Xeron, our propane and crude oil trading subsidiary that wound down its operations shortly after the first quarter of 2017. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

The remainder of our operations is presented as "Other businesses and eliminations," which consists of unregulated subsidiaries that own real estate leased to Chesapeake Utilities, as well as certain corporate costs not allocated to other operations.

The following table presents information about our reportable segments.

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Operating Revenues, Unaffiliated Customers			
Regulated Energy	**$ 332,749**	$ 316,971	$ 302,402
Unregulated Energy	**384,740**	300,612	196,458
Total operating revenues, unaffiliated customers	**$ 717,489**	$ 617,583	$ 498,860
Intersegment Revenues [1]			
Regulated Energy	**$ 12,532**	$ 9,339	$ 3,287
Unregulated Energy	**35,877**	23,983	7,321
Other businesses	**653**	774	880
Total intersegment revenues	**$ 49,062**	$ 34,096	$ 11,488
Operating Income			
Regulated Energy	**$ 79,215**	$ 74,584	$ 71,515
Unregulated Energy	**16,901**	12,631	14,066
Other businesses and eliminations	**(1,496)**	205	402
Operating Income	**94,620**	87,420	85,983
Other expense	**(615)**	(2,342)	(2,328)
Interest charges	**16,431**	12,645	10,639
Income Before Income taxes	**77,574**	72,433	73,016
Income taxes	**20,994**	14,309	28,341
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Depreciation and Amortization			
Regulated Energy	**$ 31,876**	$ 28,554	$ 25,677
Unregulated Energy	**8,845**	7,954	6,386
Other businesses and eliminations	**81**	91	96
Total depreciation and amortization	**$ 40,802**	$ 36,599	$ 32,159
Capital Expenditures			
Regulated Energy	**$ 235,912**	$ 159,011	$ 139,994
Unregulated Energy	**38,700**	26,190	23,984
Other businesses	**8,364**	5,902	5,398
Total capital expenditures	**$ 282,976**	$ 191,103	$ 169,376

[1] All significant intersegment revenues are billed at market rates and have been eliminated from consolidated revenues.

	As of December 31,	
	2018	**2017**
Identifiable Assets		
Regulated Energy	**$ 1,345,805**	$ 1,121,673
Unregulated Energy	**306,045**	259,041
Other businesses	**41,821**	34,220
Total identifiable assets	**$ 1,693,671**	$ 1,414,934

Our operations are entirely domestic.

7. Supplemental Cash Flow Disclosures

Cash paid for interest and income taxes during the years ended December 31, 2018, 2017 and 2016 were as follows:

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Cash paid for interest	**$ 16,741**	$ 12,420	$ 10,315
Cash paid for income taxes, net of refunds	**$ 477**	$ (4,114)	$ (5,308)

Non-cash investing and financing activities during the years ended December 31, 2018, 2017, and 2016 were as follows:

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Capital property and equipment acquired on account, but not paid for as of December 31	**$ 39,402**	$ 15,457	$ 9,791
Common stock issued for the Retirement Savings Plan	**$ —**	$ —	$ 777
Common stock issued under the SICP	**$ 2,006**	$ 1,127	$ 1,027
Capital lease obligation	**$ 1,310**	$ 2,070	$ 3,471

8. Derivative Instruments

We use derivative and non-derivative contracts to manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to our customers. Aspire Energy has entered into contracts with producers to secure natural gas to meet its obligations. Purchases under these contracts typically either do not meet the definition of derivatives or are considered "normal purchases and normal sales" and are accounted for on an accrual basis. Both our propane operations and our natural gas marketing operations may also enter into fair value hedges of their inventory or cash flow hedges of their future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of December 31, 2018 and 2017 our natural gas and electric distribution operations did not have any outstanding derivative contracts.

We adopted ASU 2017-12 as of July 1, 2018. See Note 1, *Summary of Significant Accounting Policies,* under the heading "recently adopted accounting standards" for additional details.

Volume of Derivative Activity

As of December 31, 2018, the volume of our open commodity derivative contracts were as follows:

Business unit	Commodity	Quantity hedged (in millions)	Designation	Longest Expiration date of hedge
PESCO/natural gas marketing	Natural gas (Dts)	14.4	Cash flows hedges	March 2022
PESCO/natural gas marketing	Natural gas (Dts)	3.8	Not designated	December 2020
Sharp/propane operations	Propane (gallons)	9.7	Cash flows hedges	June 2021
Sharp/propane operations	Propane (gallons)	0.3	Fair value hedges	March 2019

PESCO entered into natural gas futures contracts associated with the purchase and sale of natural gas to specific customers. We designated and accounted for them as cash flow hedges. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss) and later recognized in the statement of income in the same period and in the same line item as the hedged transaction. We expect to reclassify approximately $1.5 million from accumulated other comprehensive loss to earnings during the next 12-month period ending December 31, 2019.

Sharp entered into futures and swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with the propane volumes expected to be purchased during the heating season. Under the futures and swap agreements, Sharp will receive the difference between (i) the index prices (Mont Belvieu prices in August 2018 through June 2021) and (ii) the per gallon propane swap prices, to the extent the index prices exceed the contracted prices. If the index prices are lower than the swap prices, Sharp will pay the difference. We designated and accounted for propane swaps as cash flows hedges. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss) and later recognized in the statement of income in the same period and in the same line item as the hedged transaction. We expect to reclassify approximately $1.2 million from accumulated other comprehensive income to earnings during the next 12-month period ending December 31, 2019.

Balance sheet offsetting

PESCO has entered into master netting agreements with counterparties that enable it to net the counterparties' outstanding accounts receivable and payable, which are presented on a net basis in the consolidated balance sheets. The following table summarizes the accounts receivable and payables on a gross and net basis at December 31, 2018 and 2017:

	At December 31, 2018					
(in thousands)	Gross amounts		Amounts offset		Net amounts	
Accounts receivable	**$**	**12,368**	**$**	**3,834**	**$**	**8,534**
Accounts payable	**$**	**24,741**	**$**	**3,834**	**$**	**20,907**

	At December 31, 2017					
(in thousands)	Gross amounts		Amounts offset		Net amounts	
Accounts receivable	$	8,283	$	2,391	$	5,892
Accounts payable	$	16,643	$	2,391	$	14,252

Broker Margin

Futures exchanges have contract specific margin requirements that require the posting of cash or cash equivalents relating to traded contracts. Margin requirements consist of initial margin that is posted upon the initiation of a position, maintenance margin that is usually expressed as a percent of initial margin, and variation margin that fluctuates based on the daily MTM relative to maintenance margin requirements. We maintain separate broker margin accounts for Sharp and PESCO. At December 31, 2018 and 2017, Sharp's account had a zero balance. The balances related to PESCO are as follows:

(in thousands)	**Balance Sheet Location**		**December 31, 2018**		**December 31, 2017**
PESCO	Other Current Assets	**$**	**2,810**	$	6,300

Financial Statements Presentation

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency. Fair values of the derivative contracts recorded in the consolidated balance sheets as of December 31, 2018 and 2017 are as follows:

		Derivative Assets	
		Fair Value As Of	
(in thousands)	**Balance Sheet Location**	**December 31, 2018**	**December 31, 2017**
Derivatives not designated as hedging instruments			
Propane swap agreements	Derivative assets, at fair value	**$ —**	$ 13
Natural gas futures contracts	Derivative assets, at fair value	**4,024**	—
Derivatives designated as fair value hedges			
Propane put options	Derivative assets, at fair value	**71**	—
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative assets, at fair value	**9,059**	92
Propane swap agreements	Derivative assets, at fair value	**11**	1,181
Total Derivative Assets		**$ 13,165**	$ 1,286

		Derivative Liabilities	
		Fair Value As Of	
(in thousands)	**Balance Sheet Location**	**December 31, 2018**	**December 31, 2017**
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Derivative liabilities, at fair value	**$ 4,562**	$ 5,776
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative liabilities, at fair value	**8,705**	—
Natural gas swap contracts	Derivative liabilities, at fair value	**—**	469
Propane swap agreements	Derivative liabilities, at fair value	**1,604**	2
Total Derivative Liabilities		**$ 14,871**	$ 6,247

The effects of gains and losses from derivative instruments are as follows:

		Amount of Gain (Loss) on Derivatives:		
	Location of Gain	For the Year Ended December 31,		
(in thousands)	**(Loss) on Derivatives**	**2018**	**2017**	**2016**
Derivatives not designated as hedging instruments				
Realized gain (loss) on forward contracts and options [(1)]	Revenue	**$ —**	$ 112	$ (546)
Natural gas futures contracts	Cost of sales	**(3,189)**	(3,633)	(541)
Propane swap agreements	Cost of sales	**(13)**	8	7
Natural gas swap contracts	Cost of sales	**—**	1	—
Derivatives designated as fair value hedges				
Put/Call option	Cost of sales	**—**	(9)	49
Natural gas futures contracts	Natural gas inventory	**—**	—	(233)
Derivatives designated as cash flow hedges				
Propane swap agreements	Cost of sales	**(647)**	1,607	(364)
Propane swap agreements	Other comprehensive income (loss)	**(2,773)**	487	1,016
Natural gas futures contracts	Cost of sales	**(2,010)**	(456)	345
Natural gas swap contracts	Cost of sales	**197**	(822)	—
Natural gas futures contracts	Other comprehensive income (loss)	**532**	(1,476)	222
Natural gas swap contracts	Other comprehensive income	**200**	986	—
Total		**$ (7,703)**	$ (3,195)	$ (45)

[(1)] All of the realized and unrealized gain (loss) on forward contracts represents the effect of trading activities on our consolidated statements of income.

As of December 31, 2018, the following amounts were recorded in the consolidated balance sheets related to fair value hedges:

(in thousands)	Carrying Amount of Hedged Item		Cumulative Adjustment Included in Carrying Amount of Hedged Item	
Balance Sheet Location of Hedged Items	**At December 31, 2018**	**At December 31, 2017**	**At December 31, 2018**	**At December 31, 2017**
Inventory	$ 212	$ —	$ —	$ —

9. FAIR VALUE OF FINANCIAL INSTRUMENTS

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The three levels of the fair value hierarchy are the following:

Fair Value Hierarchy	Description of Fair Value Level	Fair Value Technique Utilized
Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities	*Investments - equity securities* - The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities. *Investments - mutual funds and other* - The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability	*Derivative assets and liabilities* - The fair values of forward contracts are measured using market transactions in either the listed or over-the-counter markets. The fair value of the propane put/call options, swap agreements and natural gas futures contracts are measured using market transactions for similar assets and liabilities in either the listed or over-the-counter markets.
Level 3	Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity)	*Investments - guaranteed income fund* - The fair values of these investments are recorded at the contract value, which approximates their fair value.

Financial Assets and Liabilities Measured at Fair Value

The following tables summarize our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy as of December 31, 2018 and 2017, respectively:

		Fair Value Measurements Using:		
As of December 31, 2018	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
(in thousands)				
Assets:				
Investments—equity securities	**$ 22**	**$ 22**	**$ —**	**$ —**
Investments—guaranteed income fund	**686**	**—**	**—**	**686**
Investments—mutual funds and other	**6,003**	**6,003**	**—**	**—**
Total investments	**6,711**	**6,025**	**—**	**686**
Derivative assets	**13,165**	**—**	**13,165**	**—**
Total assets	**$ 19,876**	**$ 6,025**	**$ 13,165**	**$ 686**
Liabilities:				
Derivative liabilities	**$ 14,871**	**$ —**	**$ 14,871**	**$ —**

As of December 31, 2017	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$ 22	$ 22	$ —	$ —
Investments—guaranteed income fund	648	—	—	648
Investments—mutual funds and other	6,086	6,086	—	—
Total investments	6,756	6,108	—	648
Derivative assets	1,286	—	1,286	—
Total assets	$ 8,042	$ 6,108	$ 1,286	$ 648
Liabilities:				
Derivative liabilities	$ 6,247	$ —	$ 6,247	$ —

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2018 and 2017:

	For the Year Ended December 31, 2018	2017
(in thousands)		
Beginning Balance	$ 648	$ 561
Purchases and adjustments	68	79
Transfers/disbursements	(41)	(53)
Investment income	11	61
Ending Balance	**$ 686**	$ 648

Investment income from the Level 3 investments is reflected in other expense, net in the consolidated statements of income.

At December 31, 2018 and 2017, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).

At December 31, 2018, long-term debt, which includes the current maturities but excludes capital lease obligations, had a carrying value of $327.2 million, compared to the estimated fair value of $323.8 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, adjusted for duration, optionality and risk profile. At December 31, 2017, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of $205.2 million, compared to a fair value of $215.4 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

See Note 17, *Employee Benefit Plans,* for fair value measurement information related to our pension plan assets.

10. Investments

The investment balances at December 31, 2018 and 2017, consisted of the following:

	As of December 31,	
(in thousands)	**2018**	**2017**
Rabbi trust (associated with the Non-Qualified Deferred Compensation Plan)	**$ 6,689**	$ 6,734
Investments in equity securities	**22**	22
Total	**$ 6,711**	$ 6,756

We classify these investments as trading securities and report them at their fair value. For the year ended December 31, 2018, we recorded net unrealized losses of $428,000 and for the years ended December 31, 2017 and 2016, we recorded net unrealized gains of $1.0 million and $379,000, respectively, in other income (expense) in the consolidated statements of income related to these investments. For the investment in the Rabbi Trust, we also have recorded an associated liability, which is included in other pension and benefit costs in the consolidated balance sheets and is adjusted each period for the gains and losses incurred by the investments in the Rabbi Trust.

11. Goodwill and Other Intangible Assets

The carrying value of goodwill as of December 31, 2018 and 2017 was as follows:

	As of December 31,	
(in thousands)	**2018**	**2017**
Goodwill		
Regulated Energy		
Florida Natural Gas Distribution[(1)]	**$ 3,353**	$ 3,353
Unregulated Energy		
Mid-Atlantic Propane Operations	**2,147**	674
Florida Propane Operations	**1,188**	1,188
Aspire Energy	**10,119**	10,119
Marlin Gas Services	**4,760**	—
Natural Gas Marketing - PESCO	**4,270**	4,270
Total Goodwill	**$ 25,837**	$ 19,604

[(1)] Florida natural gas distribution includes Chesapeake Utilities' Central Florida Gas division, FPU and FPU's Indiantown and Fort Meade divisions.

The annual impairment testing for 2018 and 2017 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2018 and 2017 are as follows:

	As of December 31,			
	2018		**2017**	
(in thousands)	**Gross Carrying Amount**	**Accumulated Amortization**	**Gross Carrying Amount**	**Accumulated Amortization**
Customer lists	**$ 7,757**	**$ 3,664**	$ 7,393	$ 2,880
Non-Compete agreements	**2,245**	**202**	270	175
Other	**270**	**199**	270	192
Total	**$ 10,272**	**$ 4,065**	$ 7,933	$ 3,247

The customer lists, non-compete agreements and other intangibles acquired in the purchases of the operating assets of several companies are being amortized over five to 41 years.

For the years ended December 31, 2018, 2017 and 2016, amortization expense of intangible assets was $818,000, $537,000, and $380,000, respectively. Amortization expense of intangible assets is expected to be $1.1 million for each of the years 2019, 2020 and 2021, $820,000 for 2022 and $813,000 for 2023.

12. INCOME TAXES

We file a consolidated federal income tax return. Income tax expense allocated to our subsidiaries is based upon their respective taxable incomes and tax credits. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. Our state returns for tax years after 2014 are subject to examination. At December 31, 2018, the 2015 and 2016 federal income tax returns are under examination, and no report has been issued at this time.

We had no net operating loss for federal income tax purposes as of December 31, 2018 and 2017. For state income tax purposes, we had net operating losses in various states of $60.1 million and $34.2 million as of December 31, 2018 and 2017, respectively, almost all of which will expire in 2037. We have recorded deferred tax assets of $2.0 million and $1.6 million related to state net operating loss carry-forwards at December 31, 2018 and 2017, respectively, but we have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will be fully utilized.

Federal Tax Reform

On December 22, 2017, President Trump signed into law the TCJA. Substantially all of the provisions of the TCJA are effective for taxable years beginning on or after January 1, 2018. The provisions significantly impacting us include the reduction of the corporate federal income tax rate from 35 percent to 21 percent. Our federal income tax expense for periods beginning on January 1, 2018 are based on the new federal corporate income tax rate. The TCJA included changes to the Internal Revenue Code, which materially impacted our 2017 financial statements. ASC 740, *Income Taxes,* requires recognition of the effects of changes in tax laws in the period in which the law is enacted. ASC 740 requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. We have completed the assessment of the impact as it relates to accounting for certain effects of the TCJA. At the date of enactment in 2017, we re-measured deferred income taxes based upon the new corporate tax rate. See Note 19, *Rates and Other Regulatory Activities,* for further discussion of the TCJA's impact on our regulated businesses.

In 2018, we elected early adoption of ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* Accordingly, we reclassified stranded tax effects resulting from the TCJA from accumulated other comprehensive loss to retained earnings, related to our employee benefit plans and commodity contracts cash flow hedges.

The following tables provide: (a) the components of income tax expense in 2018, 2017, and 2016; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2018, 2017, and 2016; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2018 and 2017.

	For the Year Ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Current Income Tax Expense			
Federal	**$ (845)**	$ 2,803	$ (4,898)
State	**660**	492	2,053
Other	**(47)**	(71)	(71)
Total current income tax expense	**(232)**	3,224	(2,916)
Deferred Income Tax Expense [1]			
Property, plant and equipment	**19,164**	8,314	31,062
Deferred gas costs	**(1,435)**	2,002	1,163
Pensions and other employee benefits	**463**	180	237
FPU merger-related premium cost and deferred gain	**(528)**	(1,148)	(572)
Net operating loss carryforwards	**(331)**	193	(9)
Other	**3,893**	1,544	(624)
Total deferred income tax expense	**21,226**	11,085	31,257
Total Income Tax Expense	**$ 20,994**	$ 14,309	$ 28,341

[1] Includes $3.5 million, $873,000 and $2.1 million of deferred state income taxes for the years 2018, 2017 and 2016, respectively.

(in thousands)	For the Year Ended December 31, 2018	2017	2016
Reconciliation of Effective Income Tax Rates			
Federal income tax expense [1]	**$ 16,291**	$ 25,351	$ 22,759
State income taxes, net of federal benefit	**4,088**	1,894	3,422
ESOP dividend deduction	**(158)**	(257)	(264)
Revaluation of deferred tax assets and liabilities	**—**	(14,299)	—
Other	**773**	1,620	2,424
Total Income Tax Expense	**$ 20,994**	$ 14,309	$ 28,341
Effective Income Tax Rate [2]	**27.06%**	19.75%	38.81%

[1] Federal income taxes were calculated at 21 percent for 2018 and 35 percent for 2017 and 2016.
[2]Effective tax rate 2017 includes the impact of the revaluation of deferred tax assets and liabilities for our unregulated businesses due to implementation of the TCJA.

(in thousands)	As of December 31, 2018	2017
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	**$ 153,423**	$ 133,581
Acquisition adjustment	**8,896**	9,323
Loss on reacquired debt	**32**	153
Deferred gas costs	**1,139**	2,574
Natural gas conversion costs	**3,987**	2,760
Other	**2,641**	2,662
Total deferred income tax liabilities	**170,118**	151,053
Deferred income tax assets:		
Pension and other employee benefits	**3,711**	4,698
Environmental costs	**1,710**	1,744
Net operating loss carryforwards	**2,010**	1,625
Self-insurance	**151**	164
Storm reserve liability	**—**	717
Other	**5,716**	6,255
Total deferred income tax assets	**13,298**	15,203
Deferred Income Taxes Per Consolidated Balance Sheets	**$ 156,820**	$ 135,850

13. LONG-TERM DEBT

Our outstanding long-term debt is shown below:

(in thousands)	As of December 31, 2018	2017
FPU secured first mortgage bonds:		
9.08% bond, due June 1, 2022	**$ 7,986**	$ 7,982
Uncollateralized Senior Notes:		
5.50% note, due October 12, 2020	**4,000**	6,000
5.93% note, due October 31, 2023	**15,000**	18,000
5.68% note, due June 30, 2026	**23,200**	26,100
6.43% note, due May 2, 2028	**7,000**	7,000
3.73% note, due December 16, 2028	**20,000**	20,000
3.88% note, due May 15, 2029	**50,000**	50,000
3.25% note, due April 30, 2032	**70,000**	70,000
3.48% note, due May 31, 2038	**50,000**	—
3.58% note, due November 30, 2038	**50,000**	—
Term Note due January 21, 2020 [1]	**30,000**	—
Promissory notes	**26**	97
Capital lease obligations	**1,310**	2,070
Less: debt issuance costs	**(567)**	(433)
Total long-term debt	**327,955**	206,816
Less: current maturities	**(11,935)**	(9,421)
Total long-term debt, net of current maturities	**$ 316,020**	$ 197,395

[1] In December of 2018 we issued a $30.0 million unsecured Term Note through PNC Bank N.A. The maturity date of the Term Note is January 21, 2020. The Term Note bears interest at a rate equal to the one month LIBOR rate plus 75 basis points. The interest rate at December 31, 2018 was 3.23%

Annual maturities

Annual maturities and principal repayments of long-term debt, excluding the capital lease obligation, are as follows:

Year	2019	2020	2021	2022	2023	Thereafter	Total
(in thousands)							
Payments	$ 10,626	$ 45,600	$ 13,600	$ 25,100	$ 20,600	$ 211,700	$ 327,226

See Note 15, *Lease Obligations,* for future payments related to the capital lease obligation.

Shelf Agreements

We have entered into Shelf Agreements with Prudential, MetLife and NYL who are under no obligation to purchase any unsecured debt.

The Prudential Shelf Agreement totaling $150.0 million was entered in October 2015 and we issued $70.0 million of 3.25 percent unsecured debt in April 2017. The Prudential Shelf Agreement was amended in September 2018 to increase the borrowing capacity to $150.0 million after which Prudential accepted our request to purchase our unsecured debt of $100.0 million at an interest rate of 3.98 percent on or before August 20, 2019. The NYL Shelf Agreement totaling $100.0 million was entered in March 2017 and we issued unsecured debt totaling $100.0 million during 2018. The NYL Shelf Agreement was amended in November 2018 to provide additional borrowing capacity of $50.0 million. As of December 31, 2018, we had not requested that MetLife purchase unsecured senior debt under the MetLife Shelf Agreement.

The following table summarizes our shelf agreements borrowing information at December 31, 2018:

(in thousands)	Total Borrowing Capacity	Less Amount of Debt Issued	Less Unfunded Commitments	Remaining Borrowing Capacity
Shelf Agreement				
Prudential Shelf Agreement	$ 220,000	$ (70,000)	$ (100,000)	$ 50,000
MetLife Shelf Agreement	150,000	—	—	150,000
NYL Shelf Agreement	150,000	(100,000)	—	50,000
Total	$ 520,000	$ (170,000)	$ (100,000)	$ 250,000

The Prudential Shelf Agreement and the NYL Shelf Agreement set forth certain business covenants to which we are subject when any note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

Secured First Mortgage Bonds

We guaranteed FPU's first mortgage bonds, which are secured by a lien covering all of FPU's property. FPU's first mortgage bonds contain a restriction that limits the payment of dividends by FPU to an amount less than the sum of $2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2018, FPU's cumulative net income base was $155.8 million, offset by restricted payments of $37.6 million, leaving $118.2 million of available dividend capacity.

The dividend restrictions in FPU's first mortgage bonds resulted in approximately $42.2 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2018. This represents approximately 8.1 percent of our consolidated net assets. Other than the dividend restrictions associated with FPU's first mortgage bonds, there are no legal, contractual or regulatory restrictions on the net assets of our subsidiaries.

Uncollateralized Senior Notes

All of our uncollateralized Senior Notes require periodic principal and interest payments as specified in each note. They also contain various restrictions. The most stringent restrictions state that we must maintain equity of at least 40.0 percent of total capitalization, and the fixed charge coverage ratio must be at least 1.2 times. The most recent Senior Notes issued in December 2013 also contain a restriction that we must maintain an aggregate net book value in our regulated business assets of at least 50.0 percent of our consolidated total assets. Failure to comply with those covenants could result in accelerated due dates and/or termination of the Senior Note agreements.

Certain uncollateralized Senior Notes contain a "restricted payments" covenant as defined in the respective note agreements. The most restrictive covenants of this type are included within the 5.93 percent Senior Note, due October 31, 2023. The covenant provides that we cannot pay or declare any dividends or make any other restricted payments in excess of the sum of $10.0 million, plus our consolidated net income accrued on and after January 1, 2003. As of December 31, 2018, the cumulative consolidated net income base was $444.3 million, offset by restricted payments of $201.5 million, leaving $242.8 million of cumulative net income free of restrictions. As of December 31, 2018, we are in compliance with all of our debt covenants.

14. SHORT-TERM BORROWINGS

At December 31, 2018 and 2017, we had $294.5 million and $251.0 million, respectively, of short-term borrowings outstanding at the weighted average interest rates of 3.44 percent and 2.42 percent, respectively. We have an aggregate of $370.0 million in credit lines comprised of five unsecured bank credit facilities with four financial institutions, with $220.0 million in total available credit, and a Revolver with five participating Lenders totaling $150.0 million. All of these facilities expire on October 31, 2019 with the exception of the Revolver which is available through October 8, 2020. We incurred commitment fees of $93,300, $131,000 and $145,000 in 2018, 2017 and 2016, respectively. The following table summarizes our short-term borrowing facilities information at December 31, 2018 and 2017.

(in thousands)	Total Facility	LIBOR Based Interest Rate	Outstanding borrowings at December 31, 2018	Outstanding borrowings at December 31, 2017	Available at December 31, 2018
Bank Credit Facility					
Committed revolving credit facility A	$ 55,000	plus 1.00 percent	**$ 25,000**	$ 55,000	**$ 30,000**
Committed revolving credit facility B	30,000	plus 1.00 percent	**15,431**	20,500	**14,569**
Short-term revolving credit note C	50,000	plus 0.80 percent	**50,000**	50,000	**—**
Committed revolving credit facility D	45,000	plus 0.85 percent	**34,672**	40,171	**10,328**
Committed revolving credit facility E	40,000	plus 0.85 percent	**40,000**	—	**—**
Committed revolving credit facility F(2)	150,000	plus up to 1.25 percent	**125,000**	75,000	**25,000**
Total short term credit facilities	$ 370,000		**$ 290,103**	$ 240,671	**$ 79,897**
Book overdrafts(1)			**4,355**	10,298	
Total short-term borrowing			**$ 294,458**	$ 250,969	

(1) If presented, these book overdrafts would be funded through the bank revolving credit facilities.

(2) This committed revolving credit facility includes a restriction that our short-term borrowings, excluding any borrowings under the committed revolving credit facility, shall not exceed $200.0 million.

We are authorized by our Board of Directors to borrow up to $350.0 million of short-term debt, as required, from these short-term lines of credit. These bank credit facilities are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal year, a funded indebtedness ratio of no greater than 65 percent. We are in compliance with all of our debt covenants.

15. LEASE OBLIGATIONS

We have entered into several operating lease arrangements for office space, land, equipment and pipeline facilities. Rent expense related to these leases for 2018, 2017 and 2016 was $3.8 million, $3.6 million and $2.5 million, respectively. As of December 31, 2018, future minimum payments under our current lease agreements are as follows:

Year(s)	2019	2020	2021	2022	2023	Thereafter	Total
(in thousands)							
Expected payments	$2,349	$1,998	$1,761	$1,689	$1,642	$5,398	$14,837

For the years ended December 31, 2018, 2017 and 2016 we paid $2.4 million ,$1.5 million and $1.5 million respectively, for capital lease arrangements related to Sandpiper's capacity, supply and operating agreement and our Mid-Atlantic propane operations' lease arrangement for property in Anne Arundel County, Maryland which it intends to purchase during the first quarter of 2019. Future minimum payments under these lease arrangements are $1.3 million in 2019.

16. STOCKHOLDERS' EQUITY

Accumulated Other Comprehensive (Loss)

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options and natural gas futures and swap contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss). In 2018, we elected early adoption of ASU 2018-02, *Reclassification of Certain Tax*

Effects from Accumulated Other Comprehensive Income. Accordingly, we reclassified stranded tax effects resulting from the TCJA from accumulated other comprehensive loss to retained earnings, related to our employee benefit plans and commodity contracts cash flow hedges.

The following table present the changes in the balance of accumulated other comprehensive loss for the years ended December 31, 2018 and 2017. All amounts in the following tables are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2016	$ (5,360)	$ 482	$ (4,878)
Other comprehensive income before reclassifications	281	159	440
Amounts reclassified from accumulated other comprehensive income/(loss)	336	(170)	166
Net current-period other comprehensive income/(loss)	617	(11)	606
As of December 31, 2017	(4,743)	471	(4,272)
Other comprehensive loss before reclassifications	(602)	(3,130)	(3,732)
Amounts reclassified from accumulated other comprehensive income	439	1,759	2,198
Net current-period other comprehensive loss	(163)	(1,371)	(1,534)
Stranded tax reclassification to retained earnings	(1,022)	115	(907)
As of December 31, 2018	**$ (5,928)**	**$ (785)**	**$ (6,713)**

The following table presents amounts reclassified out of accumulated other comprehensive income (loss) for the years ended December 31, 2018, 2017 and 2016. Deferred gains and losses of our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	For the Year Ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Amortization of defined benefit pension and postretirement plan items:			
Prior service cost [(1)]	**$ 77**	$ 77	$ 77
Net gain [(1)]	**(579)**	(636)	(871)
Total before income taxes	**(502)**	(559)	(794)
Income tax benefit	**63**	223	320
Net of tax	**$ (439)**	$ (336)	$ (474)
Gains and losses on commodity contracts cash flow hedges			
Propane swap agreements [(2)]	**$ (647)**	$ 1,607	$ (322)
Natural gas swaps [(2)]	**197**	(822)	—
Natural gas futures [(2)]	**(2,010)**	(456)	345
Total before income taxes	**(2,460)**	329	23
Income tax impact	**701**	(159)	(3)
Net of tax	**$ (1,759)**	$ 170	$ 20
Total reclassifications for the period	**$ (2,198)**	$ (166)	$ (454)

(1) These amounts are included in the computation of net periodic benefits. See Note 17*, Employee Benefit Plans*, for additional details.
(2) These amounts are included in the effects of gains and losses from derivative instruments. See Note 8, *Derivative Instruments*, for additional details.

Amortization of defined benefit pension and postretirement plan items is included in other expense, net and gains and losses on propane swap agreements, call options and natural gas futures contracts are included in cost of sales in the accompanying consolidated statements of income. The income tax benefit is included in income tax expense in the accompanying consolidated statements of income.

17. EMPLOYEE BENEFIT PLANS

We measure the assets and obligations of the defined benefit pension plans and other postretirement benefits plans to determine the plans' funded status as of the end of the year. We record as a component of other comprehensive income/loss or a regulatory asset the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit costs.

Defined Benefit Pension Plans

We sponsor three defined benefit pension plans: the Chesapeake Pension Plan, the FPU Pension Plan and the Chesapeake unfunded supplemental executive retirement pension plan ("SERP").

The Chesapeake Pension Plan, a qualified plan, was closed to new participants, effective January 1, 1999, and was frozen with respect to additional years of service and additional compensation, effective January 1, 2005. Benefits under the Chesapeake Pension Plan were based on each participant's years of service and highest average compensation, prior to the freezing of the plan. Active participants on the date the Chesapeake Pension Plan was frozen were credited with two additional years of service.

The FPU Pension Plan, a qualified plan, covers eligible FPU non-union employees hired before January 1, 2005 and union employees hired before the respective union contract expiration dates in 2005 and 2006. Prior to the FPU merger, the FPU Pension Plan was frozen with respect to additional years of service and additional compensation, effective December 31, 2009.

The Chesapeake SERP, a nonqualified plan, is comprised of two sub-plans. The first sub-plan was frozen with respect to additional years of service and additional compensation as of December 31, 2004. Benefits under the Chesapeake SERP were based on each participant's years of service and highest average compensation, prior to the freezing of the plan. Active participants on the date the Chesapeake SERP was frozen were credited with two additional years of service. The second sub-plan provides fixed payments for several executives who joined the Company as a result of an acquisition and whose agreements with the Company provided for this benefit.

The unfunded liability for all three plans at both December 31, 2018 and 2017, is included in the other pension and benefit costs liability in our consolidated balance sheets.

The following schedule sets forth the funded status at December 31, 2018 and 2017 and the net periodic cost for the years ended December 31, 2018, 2017 and 2016 for the Chesapeake and FPU Pension Plans as well as the Chesapeake SERP:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP	
At December 31,	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
(in thousands)						
Change in benefit obligation:						
Benefit obligation — beginning of year	**$11,443**	$ 11,355	**$ 64,664**	$ 63,832	**$ 2,428**	$ 2,428
Interest cost	**384**	402	**2,339**	2,482	**83**	89
Actuarial loss (gain)	**(610)**	454	**(4,739)**	1,199	**(74)**	63
Benefits paid	**(505)**	(768)	**(2,887)**	(2,849)	**(152)**	(152)
Benefit obligation — end of year	**10,712**	11,443	**59,377**	64,664	**2,285**	2,428
Change in plan assets:						
Fair value of plan assets — beginning of year	**9,350**	8,668	**48,396**	43,272	**—**	—
Actual return on plan assets	**(647)**	1,144	**(3,113)**	6,025	**—**	—
Employer contributions	**451**	306	**1,205**	1,948	**152**	152
Benefits paid	**(505)**	(768)	**(2,887)**	(2,849)	**(152)**	(152)
Fair value of plan assets — end of year	**8,649**	9,350	**43,601**	48,396	**—**	—
Reconciliation:						
Funded status	**(2,063)**	(2,093)	**(15,776)**	(16,268)	**(2,285)**	(2,428)
Accrued pension cost	**$(2,063)**	$ (2,093)	**$(15,776)**	$(16,268)	**$ (2,285)**	$ (2,428)
Assumptions:						
Discount rate	**4.00%**	3.50%	**4.25%**	3.75%	**4.00%**	3.50%
Expected return on plan assets	**6.00%**	6.00%	**6.50%**	6.50%	**—%**	—%

For the Years Ended December 31,	Chesapeake Pension Plan 2018	2017	2016	FPU Pension Plan 2018	2017	2016	Chesapeake SERP 2018	2017	2016
(in thousands)									
Components of net periodic pension cost:									
Interest cost	**$ 384**	$ 402	$ 421	**$ 2,339**	$ 2,482	$ 2,525	**$ 83**	$ 89	$ 91
Expected return on assets	**(542)**	(495)	(501)	**(3,091)**	(2,779)	(2,702)	**—**	—	
Amortization of actuarial loss	**343**	399	459	**404**	513	519	**101**	87	87
Settlement expense	**—**	—	161	**—**	—	—			
Net periodic pension cost(1)	**185**	306	540	**(348)**	216	342	**184**	176	178
Amortization of pre-merger regulatory asset	**—**	—	—	**761**	761	761	**—**	—	—
Total periodic cost	**$ 185**	$ 306	$ 540	**$ 413**	$ 977	$ 1,103	**$ 184**	$ 176	$ 178
Assumptions:									
Discount rate	**3.50%**	3.75%	3.75%	**3.75%**	4.00%	4.00%	**3.50%**	3.75 %	3.75 %
Expected return on plan assets	**6.00%**	6.00%	6.00%	**6.50%**	6.50%	6.50%	**—%**	—%	—%

(1) As a result of our adoption of ASU 2017-07 on January 1, 2018, the "other than service" cost components of the net periodic costs have been recorded or reclassified to other income (expense), net in the consolidated statements of income.

Included in the net periodic costs for the FPU Pension Plan is continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated operations for the changes in funded status that occurred, but were not recognized as part of net periodic cost, prior to the merger with Chesapeake Utilities in October 2009. This was previously deferred as a regulatory asset to be recovered through rates pursuant to an order by the Florida PSC. The unamortized balance of this regulatory asset was $543,000 and $1.3 million at December 31, 2018 and 2017, respectively.

Our funding policy provides that payments to the trustee of each qualified plan shall be equal to at least the minimum funding requirements of the Employee Retirement Income Security Act of 1974. The following schedule summarizes the assets of the Chesapeake Pension Plan and the FPU Pension Plan, by investment type, at December 31, 2018, 2017 and 2016:

At December 31,	Chesapeake Pension Plan 2018	2017	2016	FPU Pension Plan 2018	2017	2016
Asset Category						
Equity securities	**49.02%**	52.70%	52.93%	**50.04%**	55.17%	53.18%
Debt securities	**40.98%**	37.79%	37.64%	**41.06%**	36.56%	37.74%
Other	**10.00%**	9.51%	9.43%	**8.90%**	8.27%	9.08%
Total	**100.00%**	100.00%	100.00%	**100.00%**	100.00%	100.00%

The investment policy of both the Chesapeake Utilities and FPU Pension Plans is designed to provide the capital assets necessary to meet the financial obligations of the plans. The investment goals and objectives are to achieve investment returns that, together with contributions, will provide funds adequate to pay promised benefits to present and future beneficiaries of the plans, earn a long-term investment return in excess of the growth of the plans' retirement liabilities, minimize pension expense and cumulative contributions resulting from liability measurement and asset performance, and maintain a diversified portfolio to reduce the risk of large losses.

The following allocation range of asset classes is intended to produce a rate of return sufficient to meet the plans' goals and objectives:

Asset Allocation Strategy

Asset Class	Minimum Allocation Percentage	Maximum Allocation Percentage
Domestic Equities (Large Cap, Mid Cap and Small Cap)	14%	32%
Foreign Equities (Developed and Emerging Markets)	13%	25%
Fixed Income (Inflation Bond and Taxable Fixed)	26%	40%
Alternative Strategies (Long/Short Equity and Hedge Fund of Funds)	6%	14%
Diversifying Assets (High Yield Fixed Income, Commodities, and Real Estate)	7%	19%
Cash	0%	5%

Due to periodic contributions and different asset classes producing varying returns, the actual asset values may temporarily move outside of the intended ranges. The investments are monitored on a quarterly basis, at a minimum, for asset allocation and performance.

At December 31, 2018 and 2017, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

	Fair Value Measurement Hierarchy							
	At December 31, 2018				At December 31, 2017			
Asset Category	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
(in thousands)								
Mutual Funds - Equity securities								
U.S. Large Cap [(1)]	**$ 3,399**	**$ —**	**$ —**	**$ 3,399**	$ 4,245	$ —	$ —	$ 4,245
U.S. Mid Cap [(1)]	**1,478**	**—**	**—**	**1,478**	1,775	—	—	1,775
U.S. Small Cap [(1)]	**670**	**—**	**—**	**670**	918	—	—	918
International [(2)]	**9,226**	**—**	**—**	**9,226**	11,916	—	—	11,916
Alternative Strategies [(3)]	**5,726**	**—**	**—**	**5,726**	5,528	—	—	5,528
	20,499	**—**	**—**	**20,499**	24,382	—	—	24,382
Mutual Funds - Debt securities								
Fixed income [(4)]	**18,630**	**—**	**—**	**18,630**	18,454	—	—	18,454
High Yield [(4)]	**2,818**	**—**	**—**	**2,818**	2,772	—	—	2,772
	21,448	**—**	**—**	**21,448**	21,226	—	—	21,226
Mutual Funds - Other								
Commodities [(5)]	**1,902**	**—**	**—**	**1,902**	2,154	—	—	2,154
Real Estate [(6)]	**2,216**	**—**	**—**	**2,216**	2,300	—	—	2,300
Guaranteed deposit [(7)]	**—**	**—**	**627**	**627**	—	—	436	436
	4,118	**—**	**627**	**4,745**	4,454	—	436	4,890
Total Pension Plan Assets in fair value hierarchy	**$46,065**	**$ —**	**$ 627**	**46,692**	$ 50,062	$ —	$ 436	50,498
Investments measured at net asset value [(8)]				**5,558**				7,248
Total Pension Plan Assets				**$ 52,250**				$ 57,746

(1) Includes funds that invest primarily in United States common stocks.
(2) Includes funds that invest primarily in foreign equities and emerging markets equities.
(3) Includes funds that actively invest in both equity and debt securities, funds that sell short securities and funds that provide long-term capital appreciation. The funds may invest in debt securities below investment grade.
(4) Includes funds that invest in investment grade and fixed income securities.
(5) Includes funds that invest primarily in commodity-linked derivative instruments and fixed income securities.
(6) Includes funds that invest primarily in real estate.
(7) Includes investment in a group annuity product issued by an insurance company.

(8) Certain investments that were measured at net asset value per share have not been classified in the fair value hierarchy. These amounts are presented to reconcile to total pension plan assets.

At December 31, 2018 and 2017, all of the investments were classified under the same fair value measurement hierarchy (Level 1 through Level 3) described under Note 9*, Fair Value of Financial Instruments*. The Level 3 investments were recorded at fair value based on the contract value of annuity products underlying guaranteed deposit accounts, which was calculated using discounted cash flow models. The contract value of these products represented deposits made to the contract, plus earnings at guaranteed crediting rates, less withdrawals and fees.

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2018 and 2017:

	For the Year Ended December 31,	
	2018	**2017**
(in thousands)		
Balance, beginning of year	**$ 436**	$ 498
Purchases	**1,674**	2,271
Transfers in	**2,375**	1,743
Disbursements	**(3,872)**	(4,101)
Investment income	**14**	25
Balance, end of year	**$ 627**	$ 436

Other Postretirement Benefits Plans

We sponsor two defined benefit postretirement health plans: the Chesapeake Postretirement Plan and the FPU Medical Plan. The following table sets forth the funded status at December 31, 2018 and 2017 and the net periodic cost for the years ended December 31, 2018, 2017, and 2016:

	Chesapeake Postretirement Plan		FPU Medical Plan	
At December 31,	**2018**	**2017**	**2018**	**2017**
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	**$ 1,128**	$ 1,132	**$ 1,287**	$ 1,349
Interest cost	**38**	41	**47**	50
Plan participants contributions	**136**	118	**41**	48
Actuarial loss (gain)	**(131)**	72	**(89)**	(48)
Benefits paid	**(169)**	(235)	**(99)**	(112)
Benefit obligation — end of year	**1,002**	1,128	**1,187**	1,287
Change in plan assets:				
Fair value of plan assets — beginning of year	**—**	—	**—**	—
Employer contributions(1)	**33**	117	**58**	64
Plan participants contributions	**136**	118	**41**	48
Benefits paid	**(169)**	(235)	**(99)**	(112)
Fair value of plan assets — end of year	**—**	—	**—**	—
Reconciliation:				
Funded status	**(1,002)**	(1,128)	**(1,187)**	(1,287)
Accrued postretirement cost	**$ (1,002)**	$ (1,128)	**$ (1,187)**	$ (1,287)
Assumptions:				
Discount rate	**4.00%**	3.50%	**4.25%**	3.75%

(1) The Chesapeake Postretirement Plan does not receive a Medicare Part-D subsidy. The FPU Medical Plan did not receive a significant subsidy for the post-merger period.

Net periodic postretirement benefit costs for 2018, 2017, and 2016 include the following components:

	Chesapeake Postretirement Plan			FPU Medical Plan		
For the Years Ended December 31, *(in thousands)*	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Components of net periodic postretirement cost:						
Interest cost	**$ 38**	$ 41	$ 43	**$ 47**	$ 50	$ 55
Amortization of actuarial loss	**58**	53	64	**—**	—	—
Amortization of prior service cost (credit)	**(77)**	(77)	(77)	**—**	—	—
Net periodic cost	**19**	17	30	**47**	50	55
Amortization of pre-merger regulatory asset	**—**	—	—	**8**	8	8
Total periodic cost[(1)]	**$ 19**	$ 17	$ 30	**$ 55**	$ 58	$ 63
Assumptions						
Discount rate	**3.50%**	3.75%	3.75%	**3.75%**	4.00%	4.00%

(1) As a result of our adoption of ASU 2017-07 on January 1, 2018, the "other than service" cost components of the net periodic costs have been recorded or reclassified to other income (expense), net in the condensed consolidated statements of income.

Similar to the FPU Pension Plan, continued amortization of the FPU Medical Plan regulatory asset related to the unrecognized cost prior to the merger with Chesapeake Utilities was included in the net periodic cost. The unamortized balance of this regulatory asset was $14,000 and $22,000 at December 31, 2018 and 2017, respectively.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive loss or as a regulatory asset as of December 31, 2018:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ —	$ —	$ —	$ (524)	$ —	$ (524)
Net loss (gain)	3,865	18,544	559	578	(79)	23,467
Total	$ 3,865	$ 18,544	$ 559	$ 54	$ (79)	$ 22,943
Accumulated other comprehensive loss (gain) pre-tax[(1)]	$ 3,865	$ 3,523	$ 559	$ 54	$ (15)	$ 7,986
Post-merger regulatory asset	—	15,021	—	—	(64)	14,957
Subtotal	3,865	18,544	559	54	(79)	22,943
Pre-merger regulatory asset	—	543	—	—	14	557
Total unrecognized cost	$ 3,865	$ 19,087	$ 559	$ 54	$ (65)	$ 23,500

[(1)] The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2018 is net of income tax benefits of $2.1 million.

Pursuant to a Florida PSC order, FPU continues to record as a regulatory asset a portion of the unrecognized pension and postretirement benefit costs after the merger with Chesapeake Utilities related to its regulated operations, which is included in the above table as a post-merger regulatory asset. FPU also continues to maintain and amortize a portion of the unrecognized pension and postretirement benefit costs prior to the merger with Chesapeake Utilities related to its regulated operations, which is shown as a pre-merger regulatory asset.

Assumptions

The assumptions used for the discount rate to calculate the benefit obligations were based on the interest rates of high-quality bonds in 2018, considering the expected lives of each of the plans. In determining the average expected return on plan assets for each applicable plan, various factors, such as historical long-term return experience, investment policy and current and expected allocation, were considered. Since Chesapeake Utilities' plans and FPU's plans have different expected plan lives, particularly in light of the lump-sum-payment option provided in the Chesapeake Pension Plan, different assumptions regarding discount rate and expected return on plan assets were selected for Chesapeake Utilities' and FPU's plans. Since both pension plans are frozen with respect to additional years of service and compensation, the rate of assumed compensation increases is not applicable.

The health care inflation rate for 2018 used to calculate the benefit obligation is 5.0 percent for medical and 6.0 percent for prescription drugs for the Chesapeake Postretirement Plan; and 5.0 percent for both medical and prescription drugs for the FPU Medical Plan.

Estimated Future Benefit Payments

In 2019, we expect to contribute $163,000 and $1.2 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $383,000 to the Chesapeake SERP. We also expect to contribute $96,000 and $94,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2019.

The schedule below shows the estimated future benefit payments for each of the plans previously described:

(in thousands)	Chesapeake Pension Plan[1]	FPU Pension Plan[1]	Chesapeake SERP[2]	Chesapeake Postretirement Plan[2]	FPU Medical Plan[2]
2019	$ 528	$ 3,091	$ 383	$ 96	$ 94
2020	$ 529	$ 3,221	$ 150	$ 85	$ 87
2021	$ 736	$ 3,299	$ 148	$ 82	$ 91
2022	$ 595	$ 3,485	$ 147	$ 81	$ 93
2023	$ 1,244	$ 3,558	$ 145	$ 64	$ 80
Years 2024 through 2028	$ 3,866	$ 18,570	$ 744	$ 275	$ 402

[1] The pension plan is funded; therefore, benefit payments are expected to be paid out of the plan assets.
[2] Benefit payments are expected to be paid out of our general funds.

Retirement Savings Plan

For the years ended December 31, 2018, 2017 and 2016, we sponsored a 401(k) Retirement Savings Plan. This plan is offered to all eligible employees who have completed three months of service. We match 100 percent of eligible participants' pre-tax contributions to the Retirement Savings Plan up to a maximum of six percent of eligible compensation. The employer matching contribution is made in cash and is invested based on a participant's investment directions. In addition, we may make a discretionary supplemental contribution to participants in the plan, without regard to whether or not they make pre-tax contributions. Any supplemental employer contribution is generally made in our common stock. With respect to the employer match and supplemental employer contribution, employees are 100 percent vested after two years of service or upon reaching 55 years of age while still employed by us. New employees who do not make an election to contribute and do not opt out of the Retirement Savings Plan will be automatically enrolled at a deferral rate of three percent, and the automatic deferral rate will increase by one percent per year up to a maximum of ten percent. All contributions and matched funds can be invested among the mutual funds available for investment.

Employer contributions to our Retirement Savings Plan totaled $5.5 million, $5.0 million, and $4.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, there were 831,183 shares of our common stock reserved to fund future contributions to the Retirement Savings Plan.

Non-Qualified Deferred Compensation Plan

Members of our Board of Directors, and officers designated by the Compensation Committee, are eligible to participate in the Non-Qualified Deferred Compensation Plan. Directors can elect to defer any portion of their cash or stock compensation and officers can defer up to 80 percent of their base compensation, cash bonuses or any amount of their stock bonuses (net of required withholdings). Officers may receive a matching contribution on their cash compensation deferrals up to six percent of their compensation, provided it does not duplicate a match they receive in the Retirement Savings Plan. Stock bonuses are not eligible for matching contributions. Participants are able to elect the payment of deferred compensation to begin on a specified future date or upon separation from service. Additionally, participants can elect to receive payments upon the earlier or later of a fixed date or separation from service. The payments can be made in one lump sum or annual installments for up to 15 years.

All obligations arising under the Non-Qualified Deferred Compensation Plan are payable from our general assets, although we have established a Rabbi Trust to informally fund the plan. Deferrals of cash compensation may be invested by the participants in various mutual funds (the same options that are available in the Retirement Savings Plan). The participants are credited with gains or losses on those investments. Deferred stock compensation may not be diversified. The participants are credited with dividends on our common stock in the same amount that is received by all other stockholders. Such dividends are reinvested into our common stock. Assets held in the Rabbi Trust, recorded as Investments on the consolidated balance sheet, had a fair value of $6.7 million at both December 31, 2018 and 2017. (See *Note 10, Investments*, for further details). The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Deferrals of officer base compensation and cash bonuses and directors' cash retainers are paid in cash. All deferrals of executive performance shares, which represent deferred stock units, and directors' stock retainers are paid in shares of our common stock, except that cash is paid in lieu of fractional shares. The value of our stock held in the Rabbi Trust is classified within the stockholders' equity section of the consolidated balance sheets and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Non-Qualified Deferred Compensation Plan totaled $3.9 million and $3.4 million at December 31, 2018 and 2017, respectively, which are also shown as a deduction against stockholders' equity in the consolidated balance sheet.

18. Share-Based Compensation Plans

Our non-employee directors and key employees have been granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period. We have 475,099 shares of common stock reserved for issuance under the SICP.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the SICP for the years ended December 31, 2018, 2017 and 2016:

	For the Year Ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Awards to non-employee directors	**$ 539**	$ 540	$ 580
Awards to key employees	**2,871**	1,950	1,787
Total compensation expense	**3,410**	2,490	2,367
Less: tax benefit	**(934)**	(1,003)	(952)
Share-based compensation amounts included in net income	**$ 2,476**	$ 1,487	$ 1,415

Stock Options

There were no stock options outstanding at December 31, 2018 or 2017, nor were any stock options issued during the years 2016 through 2018.

Non-employee Directors

Shares granted to non-employee directors are issued in advance of these directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2017, each of our non-employee directors received an annual retainer of 835 shares of common stock under the SICP for board service through the 2018 Annual Meeting of Stockholders; as a group, 7,515 shares, with a weighted average fair value of $71.80, were issued and vested in 2017. In May 2018, each of our non-employee directors received an annual retainer of 792 shares of common stock under the SICP for board service through the 2019 Annual Meeting of Stockholders; accordingly, 7,128 shares, with a weighted average fair value of $75.70, were issued and vested in 2018.

The intrinsic values of the shares granted to our non-employee directors are equal to the fair value of these awards on the date of grant. At December 31, 2018, there was $180,000 of unrecognized compensation expense related to these awards. This expense will be fully recognized by April 2019, which approximates the expected remaining service period of those directors.

Key Employees

Our Compensation Committee is authorized to grant our key employees the right to receive awards of shares of our common stock, contingent upon the achievement of established performance goals and subject to SEC transfer restrictions once awarded.

We currently have several outstanding multi-year performance plans, which are based upon the successful achievement of long-term goals, growth and financial results and comprise both market-based and performance-based conditions or targets. The fair value per share, tied to a performance-based condition or target, is equal to the market price per share on the grant date. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each share granted.

The table below presents the summary of the stock activity for awards to key employees:

	Number of Shares	Weighted Average Fair Value
Outstanding — December 31, 2016	115,091	$ 51.85
Granted	52,355	$ 63.42
Vested	(32,926)	$ 38.88
Expired	(1,878)	$ 39.97
Outstanding — December 31, 2017	132,642	$ 59.31
Granted	49,494	$ 67.76
Vested	(29,786)	$ 47.39
Vested - Accelerated pursuant to separation agreement (1)	(16,676)	$ 75.78
Expired	(3,933)	$ 49.66
Outstanding — December 31, 2018	**131,741**	**$ 67.24**

(1) Includes 2,569 shares that were forfeited

The intrinsic value of these awards was $10.7 million, $10.4 million and $7.7 million in 2018, 2017 and 2016, respectively. At December 31, 2018, there was $2.1 million of unrecognized compensation cost related to these awards, which is expected to be recognized during 2019 through 2020.

In 2018, 2017 and 2016, we withheld shares with a value at least equivalent to the employees' minimum statutory obligation for the applicable income and other employment taxes, and remitted the cash to the appropriate taxing authorities with the executives electing to receive the net shares. The below table presents the number of shares withheld, amounts remitted to taxing authorities and the tax benefits associated with these obligations:

	For the Year Ended December 31,		
(amounts except shares, in thousands)	**2018**	**2017**	**2016**
Shares withheld to satisfy tax obligations	**10,436**	10,269	12,031
Amounts remitted to tax authorities to satisfy obligations	**$ 1,210**	$ 692	$ 770
Tax benefit associated with settlement of share based payments	**$ —**	$ 349	285

In June 2018, the Company and a former executive officer entered into a separation agreement and release (the "Separation Agreement"). Pursuant to the Separation Agreement, three awards, representing a total of 14,107 shares of common stock previously granted to the executive officer under the SICP, immediately vested at the time of separation, and an additional 2,569 shares were forfeited. We settled the awards that vested in cash and recognized $1.1 million as share-based compensation expense.

19. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC.

Delaware

Underserved Area Rates: In December 2017, we filed an application requesting authorization to utilize existing expansion area tariff rates to serve customers located outside of the current Sussex County, Delaware expansion area boundaries that cannot be economically served under the regular tariff rates. In June 2018, we reached a settlement agreement with the relevant parties, which allows us to utilize higher rates for areas outside of our existing expansion area. The Delaware PSC unanimously approved the settlement at its public meeting on July 10, 2018. The new rate schedule became effective on August 1, 2018.

CGS: In June 2018, we filed with the Delaware PSC an application requesting approval of the acquisition, and subsequent conversion to natural gas of certain CGS located within our service territory. We requested the establishment of regulatory accounting treatment and valuation of the proposed acquisition, approval of a methodology to set new distribution rates for CGS customers and approval of a new system-wide tariff rate that will recover CGS conversion costs. The application included a request that the Delaware PSC regulate the propane CGS systems after their acquisition but before conversion to natural gas. In late 2018, the Delaware PSC ruled that it did not have jurisdiction over these propane CGS systems and could not approve the methodology given the lack of jurisdiction. We are considering proposing legislation to clarify the Delaware PSC jurisdiction or we may redesign the application and re-file.

Effect of the TCJA on customers: The Delaware PSC issued an order requiring all rate-regulated utilities to: (i) file estimates of the impact of the TCJA on their cost of service for the most recent test year available (including new rate schedules), and (ii) propose procedures for changing rates to reflect those impacts on or before March 31, 2018. In addition, on February 1, 2018, the Delaware PSC issued an order requiring Delaware rate-regulated public utilities to accrue regulatory liabilities reflecting the impacts of changes in the federal corporate income tax laws. In compliance with the Delaware PSC order, we have established a regulatory liability to reflect the estimated impacts of the changes in the federal corporate income tax rate. On May 31, 2018, our Delaware Division filed the information requested by the PSC, including an updated report reflecting the impact of the TCJA. On January 31, 2019, the Delaware PSC approved the as-filed Delaware Division Delivery Service Rates reflecting the impact of the TCJA. The new rates will go into effect March 1, 2019, and the Company will have to complete refunds back to February 2018, per the Commission's previous order, by June 30, 2019. The order also provides for a line item billing credit to go into effect on April 1, 2019, for the return of the excess deferred income taxes. Additional information on the TCJA impact is included in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

Maryland

Effect of the TCJA on customers: In April 2018, the Maryland PSC issued orders related to the TCJA impact on both the Maryland Division and Sandpiper operations. Please see the actions taken in conjunction with these orders in the TCJA table at the end of this Note 19, *Rates and Other Regulatory Activities*. Additionally, if in the future the Maryland Division or Sandpiper identifies any additional tax savings, we must submit an additional filing to the Maryland PSC in order to return those savings to customers as soon as possible.

Florida

Florida Electric Reliability/Modernization Pilot Program: In July 2017, our Florida electric operations filed a petition with the Florida PSC requesting approval to include $15.2 million of certain capital project expenditures in its rate base and to adjust its base rates accordingly. These expenditures are designed to improve the stability and safety of the electric system, while enhancing the capability of our electrical grid. In December 2017, the Florida PSC approved this petition, effective January 1, 2018. The settlement agreement prescribed the methodology for adjusting the new rates based on the lower federal income tax rate and the process and methodology regarding the refund of deferred income taxes, reclassified as a regulatory liability, as a result of the TCJA. More details about this methodology are included in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

Electric Limited Proceeding-Storm Recovery: In February 2018, FPU filed a petition with the Florida PSC, requesting recovery of incremental storm restoration costs related to several hurricanes and tropical storms, along with the replenishment of the storm reserve to its pre-storm level of $1.5 million. As a result of these hurricanes and tropical storms, FPU's storm reserve was depleted and, at the time of this filing, had a deficit of $779,000. We requested approval of a surcharge of $1.82 per kilowatt hour for two years to recover storm-related costs and replenish the storm reserve. FPU filed written testimony on this matter in August 2018. This matter was heard before the Florida PSC in December 2018, final legal briefs were submitted and, on January 14, 2019, and is scheduled for approval at Agenda on March 5, 2019.

In October 2018, Hurricane Michael passed through Florida Public Utilities Company's ("FPU") electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure resulting in 100 percent of its customers losing electrical service. FPU has restored service to those customers who were able to accept service following Hurricane Michael after a significant hurricane restoration effort. In conjunction with restoring these services, FPU expended over $60.0 million to restore service, which has been recorded as new plant and equipment or charged against FPU's storm reserve. We are preparing the necessary regulatory filings to seek recovery for the costs incurred, including replenishment of FPU's storm reserve. In conjunction with the hurricane-related expenditures, we executed two 13-month unsecured term loans as temporary financing, each in the amount of $30.0 million. The interest cost associated with these loans is LIBOR plus 75 basis points. One of the term loans was executed in December 2018 and the other was executed in January 2019. The storm did not have a material impact on the Company's financial results in 2018, and is not expected to have a significant impact going forward assuming reasonable regulatory treatment.

Effect of the TCJA on customers: In February 2018, the Florida PSC opened dockets to consider the impacts associated with the TCJA. In May 2018, FPU's natural gas division filed petitions and supporting testimony regarding the disposition of the related impacts of the TCJA. Hearings on this matter took place in November 2018, The Florida PSC approved staff's recommendations on February 5, 2019. Final orders were issued on February 25, 2019, and are subject to a 30-day appeal period. Staff's recommendations are summarized in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

Eastern Shore

2017 Expansion Project: In October 2017, the FERC issued a Certificate of Public Convenience and Necessity authorizing Eastern Shore to construct this project, the largest expansion in Eastern Shore's history. The facilities include approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional compressor unit at Eastern Shore's existing Daleville compressor station in Chester County, Pennsylvania; and approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. Eastern Shore entered into precedent agreements with seven existing customers, including three affiliates of Chesapeake Utilities, for a total of 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system and an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities.

The first phase of the project was placed into service in December 2017 and, as of December 31, 2018, we have substantially completed construction. The TETLP interconnect upgrade was placed into service in December 2017, and the Fair Hill Loop, the Jennersville Loop, the Daleville Compressor Station, the Seaford-Millsboro Connector, and the Millsboro Pressure Control Station were placed into service at various dates in 2018. The Parkesburg Loop was placed into service in January 2019. The few remaining segments are expected to be placed into service in various phases during the first half of 2019.

2017 Rate Case Filing: In January 2017, Eastern Shore filed a base rate proceeding with the FERC. In August 2017, Eastern Shore implemented the proposed new rates, subject to refund, based on the outcome of the rate proceeding. Eastern Shore recorded incremental revenue of approximately $3.7 million for the year ended December 31, 2017, and established a regulatory liability to reserve a portion of the total incremental revenues generated by the new rates pending FERC approval of a settlement agreement and refunds to customers according to the terms of the settlement. The FERC approved the settlement agreement in February 2018, and it became final in March 2018. In April 2018, Eastern Shore refunded to its customers, with interest, the difference between the proposed rates and the settlement rates. Exclusive of the TCJA impact, which is discussed below, base rates increased, on an annual basis, by approximately $9.8 million.

Effect of the TCJA on customers: In March 2018, Eastern Shore filed with the FERC its revised base rates, reflecting the reduction in its federal corporate income tax rate. These adjusted base rates became effective January 1, 2018 and will generate approximately $6.6 million in incremental margin, on an annual basis. Other information about the impact of the TCJA on ESNG has been included in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

In October 2018, the FERC issued an order granting a waiver to Eastern Shore. In April 2018, Eastern Shore consummated a filing, which included its comments associated with the United Airlines, Inc. vs. FERC proceeding and requested confirmation from the FERC that Eastern Shore is not required to provide an informational filing because of its implementation of lower rates in accordance with the 2017 rate case settlement agreement.

Del-Mar Energy Pathway Project: In September 2018, Eastern Shore filed a Certificate Application with the FERC, requesting authorization to construct and operate the Del-Mar Energy Pathway project, which will provide an additional 14,300 Dts/d of capacity to four customers. Facilities to be constructed include six miles of pipeline looping in Delaware; 13 miles of new mainline extension in Sussex County, Delaware and Somerset County, Maryland; and new pressure control and delivery stations in these counties. The benefits of this project include: (i) further natural gas transmission pipeline infrastructure in eastern Sussex County, Delaware, and (ii) extension of Eastern Shore's pipeline system, for the first time, into Somerset County, Maryland. During the fourth quarter of 2018, the FERC held a full project area scoping meeting in Sussex County, Delaware and issued a Notice of Schedule for Environmental Review, indicating issuance of its Environmental Assessment for the Del-Mar Energy Pathway project by April 1, 2019.

Summary TCJA Table

	Regulatory Liabilities related to Excess Accumulated Deferred Income Taxes ("ADIT")		Status of Customer Rate impact related to 35 percent to 21 percent rate change
Operation and Regulatory Jurisdiction	**Amount (in thousands)**	**Status**	
Eastern Shore (FERC)	$34,190	Will be addressed in Eastern Shore's next rate case filing	Implemented one-time bill credit (totaling $900,000) in April 2018 - Customer rates adjusted in April, 2018
Delaware Division (Delaware PSC)	$13,262	In January 2019, PSC approved amortization of ADIT and corresponding customer rate reductions effective March 1, 2019.	Customer rates to be adjusted March 1, 2019. One-time bill credit to be implemented during the second quarter.
Maryland Division (Maryland PSC)	$4,211	In May 2018, PSC approved amortization of ADIT and corresponding customer rate reductions commenced	Implemented one-time bill credit (totaling $365,000) in July 2018 - Customer rates adjusted effective May 1, 2018
Sandpiper Energy (Maryland PSC)	$3,815	In May 2018, PSC approved amortization of ADIT and corresponding customer rate reductions commenced	Implemented one-time bill credit (totaling $608,000) in July 2018 - Customer rates adjusted effective May 1, 2018
Chesapeake Florida Gas Division/Central Florida Gas (Florida PSC)	$8,471	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019 The order states that the net ADIT liability would be amortized and retained by the Company pursuant to the prescribed schedule	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019 No one-time bill credit or adjustment in rates would be applied; the tax savings arising from the TCJA rate reduction would be retained
FPU Natural Gas (includes FPU, Fort Meade, and Indiantown) (Florida PSC)	$19,505	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019 The order states that the net ADIT liability would be amortized and retained by the Company pursuant to the prescribed schedule	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019 No one-time bill credit or adjustment in rates would be applied; the tax savings arising from the TCJA rate reduction would be retained
FPU Electric (Florida PSC)	$5,995	In January 2019, PSC approved amortization of ADIT through purchased power cost recovery, storm reserve and rates.	TCJA benefit will flow back to its customers through a combination of reductions to the fuel cost recovery rate, base rates, as well as application to the storm reserve over the next several years

Regulatory Assets and Liabilities

At December 31, 2018 and 2017, our regulated utility operations had recorded the following regulatory assets and liabilities included in our consolidated balance sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers' rates.

	As of December 31,	
(in thousands)	2018	2017
Regulatory Assets		
Under-recovered purchased fuel and conservation cost recovery (1)	**$ 4,631**	$ 9,869
Under-recovered GRIP revenue (2)	**165**	164
Deferred postretirement benefits (3)	**15,517**	15,498
Deferred conversion and development costs (1)	**16,727**	11,735
Environmental regulatory assets and expenditures (4)	**2,731**	3,222
Acquisition adjustment (5)	**33,255**	39,992
Loss on reacquired debt (6)	**942**	1,031
Other	**3,250**	4,994
Total Regulatory Assets	**$ 77,218**	$ 86,505
Regulatory Liabilities		
Self-insurance (7)	**$ 947**	$ 1,013
Over-recovered purchased fuel and conservation cost recovery (1)	**5,443**	2,048
Over-recovered GRIP revenue (2)	**1,563**	2,245
Storm reserve (7)	**677**	669
Accrued asset removal cost (8)	**42,401**	40,948
Deferred income taxes due to rate change (9)	**91,162**	98,492
Other	**729**	2,048
Total Regulatory Liabilities	**$ 142,922**	$ 147,463

(1) We are allowed to recover the asset or are required to pay the liability in rates. We do not earn an overall rate of return on these assets.
(2) The Florida PSC allowed us to recover through a surcharge, capital and other program-related-costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services (defined as any material other than coated steel or plastic) in FPU's natural gas distribution, Fort Meade division and Chesapeake Utilities' Central Florida Gas division. We are allowed to recover the asset or are required to pay the liability in rates related to GRIP.
(3) The Florida PSC allowed FPU to treat as a regulatory asset the portion of the unrecognized costs pursuant to ASC Topic 715*, Compensation - Retirement Benefits*, related to its regulated operations. See Note 17, *Employee Benefit Plans,* for additional information.
(4) All of our environmental expenditures incurred to date and our current estimate of future environmental expenditures have been approved by various PSCs for recovery. See Note 20*, Environmental Commitments and Contingencies*, for additional information on our environmental contingencies.
(5) We are allowed to include the premiums paid in various natural gas utility acquisitions in Florida in our rate bases and recover them over a specific time period pursuant to the Florida PSC approvals. Included in these amounts are $543,000 of the premium paid by FPU, $34.2 million of the premium paid by us in 2009, including a gross up for income tax, because it is not tax deductible, and $746,000 of the premium paid by FPU in 2010.
(6) Gains and losses resulting from the reacquisition of long-term debt are amortized over future periods as adjustments to interest expense in accordance with established regulatory practice.
(7) We have self-insurance and storm reserves in our Florida regulated energy operations that allow us to collect through rates amounts to be used against general claims, storm restoration costs and other losses as they are incurred.
(8) See Note 1*, Summary of Significant Accounting Policies,* for additional information on our asset removal cost policies.
(9) We recorded a regulatory liability for our regulated businesses related to the revaluation of accumulated deferred tax assets/liabilities as a result of the TCJA. Based upon the regulatory proceedings, we will pass back the respective portion of the excess accumulated deferred taxes to rate payers. See Note 12, *Income Taxes*, for additional information.

20. Environmental Commitments and Contingencies

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remediate, at current and former operating sites, the effect on the environment of the disposal or release of specified substances.

MGP Sites

We have participated in the investigation, assessment or remediation of, and have exposures at, seven former MGP sites. We have received approval for recovery of clean-up costs in rates for six sites located in Salisbury, Maryland, Seaford, Delaware and Winter

Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the MDE regarding a former MGP site located in Cambridge, Maryland.

As of December 31, 2018, we had approximately $9.1 million in environmental liabilities, related to FPU's MGP sites in Key West, Pensacola, Sanford and West Palm Beach. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to its MGP sites. As of December 31, 2018, we have recovered approximately $11.5 million, leaving approximately $2.5 million in regulatory assets for future recovery from FPU's customers.

Environmental liabilities for our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental remediation and related activities, including any potential future remediation costs for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.

The following is a summary of our remediation status and estimated costs to implement clean-up of our key MGP sites:

MGP Site (Jurisdiction)	Status	Estimated Cost to Clean Up (Expect to Recover through Rates)
West Palm Beach (Florida)	Remedial actions approved by Florida Department of Environmental Protection have been implemented on the east parcel of the site. Similar remedial actions expected to be implemented on other remaining portions.	Between $4.5 million to $15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.
Sanford (Florida)	In March 2018, the EPA approved a "site-wide ready for anticipated use" status, which is the final step before delisting a site. Construction has been completed and restrictive covenants are in place to ensure protection of human health. The only remaining activity is long-term groundwater monitoring. It is unlikely that FPU will incur any significant future costs associated with the site.	FPU's remaining remediation expenses, including attorneys' fees and costs, are anticipated to be less than $10,000.
Winter Haven (Florida)	Remediation is ongoing.	Not expected to exceed $425,000, which includes costs of implementing institutional controls at the site.
Seaford (Delaware)	Proposed plan for implementation approved by Delaware Department of Natural Resources and Environmental Control in July 2017. Site assessment is ongoing.	$273,000 to $465,000.
Cambridge (Maryland)	Currently in discussions with MDE.	Unable to estimate.

21. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

Our Delmarva Peninsula natural gas distribution operations have asset management agreements with PESCO to manage their natural gas transportation and storage capacity. The agreements were effective as of April 1, 2017, and each has a three-year term, expiring on March 31, 2020. Previously, the Delaware PSC approved PESCO to serve as an asset manager with respect to our Delaware Division.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with Eastern Gas & Water Investment Company, LLC ("EGWIC") to purchase propane through May 2019. Sandpiper's remaining commitment is approximately 1.2 million gallons. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices.

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC through May 2019. Sharp's current annual commitment is estimated at approximately 1.2 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC; neither agreement permits the set off of the rights and obligations in one agreement against those in the other agreement.

Chesapeake Utilities' Florida Division has firm transportation service contracts with FGT and Gulfstream. Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake Utilities is contingently liable to FGT and Gulfstream should any party that acquired the capacity through release fail to pay the capacity charge.

FPU's electric supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with FPL requires FPU to meet or exceed a debt service coverage ratio of 1.25 times based on the results of the prior 12 months. If FPU fails to meet this ratio, it must provide an irrevocable letter of credit or pay all amounts outstanding under the agreement within five business days. FPU's electric supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken, or proposed to be taken, to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could also result in FPU having to provide an irrevocable letter of credit. As of December 31, 2018, FPU was in compliance with all of the requirements of its fuel supply contracts.

Eight Flags provides electricity and steam generation services through its CHP plant located on Amelia Island, Florida. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU pursuant to a 20-year power purchase agreement for distribution to our electric customers. In July 2016, Eight Flags also started selling steam, pursuant to a separate 20-year contract, to the landowner on which the CHP plant is located. The CHP plant is powered by natural gas transported by FPU through its distribution system and Peninsula Pipeline through its intrastate pipeline.

The total purchase obligations for natural gas, electric and propane supplies are as follows:

Year	2019	2020-2021	2022-2023	Beyond 2023	Total
(in thousands)					
Purchase Obligations	$ 158,544	$ 74,970	$ 42,279	$ 129,019	$ 404,812

Corporate Guarantees

The Board of Directors has authorized the Company to issue corporate guarantees securing obligations of our subsidiaries and to obtain letters of credit securing our subsidiaries' obligations. The maximum authorized liability under such guarantees and letters of credit during 2018 was $95.0 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily PESCO. These corporate guarantees provide for the payment of natural gas purchases in the event that PESCO defaults. PESCO has never defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at December 31, 2018 was $76.5 million, with the guarantees expiring on various dates through December 2019.

Chesapeake Utilities also guarantees the payment of FPU's first mortgage bonds. The maximum exposure under this guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU's first mortgage bonds approximate their carrying values (see Note 13*, Long-Term Debt*, for further details).

As of December 31, 2018, we have issued letters of credit totaling approximately $7.0 million related to the electric transmission services for FPU's electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, the payment of natural gas purchases for PESCO, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through December 2019. There have been no draws on these letters of credit as of December 31, 2018. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

22. QUARTERLY FINANCIAL DATA (UNAUDITED)

In our opinion, the quarterly financial information shown below includes all adjustments necessary for a fair presentation of the operations for such periods. Due to the seasonal nature of our business, there are substantial variations in operations reported on a quarterly basis.

	For the Quarters Ended			
(in thousands except per share amounts)	**March 31**	**June 30**	**September 30**	**December 31**
2018 [1]				
Operating Revenues	**$ 239,356**	**$ 136,664**	**$ 140,279**	**$ 201,190**
Operating Income	**$ 40,406**	**$ 13,248**	**$ 12,036**	**$ 28,930**
Net Income	**$ 26,855**	**$ 6,387**	**$ 5,538**	**$ 17,801**
Earnings per share:				
Basic	**$ 1.64**	**$ 0.39**	**$ 0.34**	**$ 1.09**
Diluted	**$ 1.64**	**$ 0.39**	**$ 0.34**	**$ 1.08**
2017 [1]				
Operating Revenues	$ 185,160	$ 125,084	$ 126,936	$ 180,403
Operating Income	$ 35,099	$ 14,061	$ 14,632	$ 23,628
Net Income	$ 19,144	$ 6,046	$ 6,833	$ 26,101
Earnings per share:				
Basic	$ 1.17	$ 0.37	$ 0.42	$ 1.60
Diluted	$ 1.17	$ 0.37	$ 0.42	$ 1.59

[1] The sum of the four quarters does not equal the total for the year due to rounding.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer, with the participation of other Company officials, have evaluated our "disclosure controls and procedures" (as such term is defined under Rule 13a-15(e) and Rule 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended) as of December 31, 2018. Based upon their evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2018.

CHANGE IN INTERNAL CONTROLS

There has been no change in internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2018, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

CEO AND CFO CERTIFICATIONS

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2018. In addition, on June 8, 2018, our former Chief Executive Officer certified to the NYSE that he was not aware of any violation by us of the NYSE corporate governance listing standards.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Exchange Act. 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 GAAP. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records which in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) 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.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, our management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria established in an updated report entitled "Internal Control - Integrated Framework," issued in May 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. 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.

Our management has evaluated and concluded that our internal control over financial reporting was effective as of December 31, 2018.

Our independent auditors, Baker Tilly Virchow Krause, LLP, have audited the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their report which appears under Part II, *Item 8. Financial Statements and Supplementary Data*.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE.

In December 2018, the Company announced that its Board of Directors had appointed Jeffry M. Householder, formerly President of the Company's Florida business unit, President and Chief Executive Officer. Concurrent with his promotion, Mr. Householder was also appointed to the Company's Board of Directors. Both appointments were effective on January 1, 2019.

The Company's former President and Chief Executive Officer, Michael P. McMasters, who retired on December 31, 2018, is continuing as a member of the Company's Board of Directors.

We have adopted a Code of Ethics that applies to our principal executive officer, president, principal financial officer, principal accounting officer or controller, and persons performing similar functions, which is a "code of ethics" as defined by applicable rules of the SEC. This Code of Ethics is publicly available on our website at http://www.chpk.com/wp-content/uploads/Code_of_Ethics.pdf. If we make any amendments to this code other than technical, administrative or other non-substantive amendments, or grant any waivers, including implicit waivers, from a provision of this code to our principal executive officer, president, principal financial officer, principal accounting officer or controller, we intend to disclose the nature of the amendment or waiver, its effective date and to whom it applies by posting such information on our website at the address and location specified above.

The remaining information required by this Item is incorporated herein by reference to the sections of our Proxy Statement captioned "Election of Directors (Proposal 1)," "Overview," "Corporate Governance," "Board of Directors and its Committees" and "Section 16(a) Beneficial Ownership Reporting Compliance."

ITEM 11. EXECUTIVE COMPENSATION.

The information required by this Item is incorporated herein by reference to the sections of our Proxy Statement captioned "Director Compensation," "Executive Compensation" and "Compensation Discussion and Analysis" in the Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by this Item is incorporated herein by reference to the sections of our Proxy Statement captioned "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by this Item is incorporated herein by reference to the section of our Proxy Statement captioned "Corporate Governance."

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement captioned "Fees and Services of Independent Registered Public Accounting Firm."

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this report:

(a)(1) All of the financial statements, reports and notes to the financial statements included in Item 8 of Part II of this Annual Report on Form 10-K.

(a)(2) Schedule II—Valuation and Qualifying Accounts.

(a)(3) The Exhibits below.

- Exhibit 3.1 — Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q for the period ended June 30, 2010, File No. 001-11590.
- Exhibit 3.2 — Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 4, 2012, are incorporated herein by reference to Exhibit 3 of our Current Report on Form 8-K, filed December 7, 2012, File No. 001-11590.
- Exhibit 3.3 — First Amendment to the Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 3, 2014, is incorporated herein by reference to Exhibit 3.3 of our Annual Report on Form 10-K for the year ended December 31, 2014.
- Exhibit 3.4 — Second Amendment to the Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective November 2, 2016, is incorporated herein by reference to Exhibit 3.3 of our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016, File No. 001-11590.
- Exhibit 3.5 — Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed May 9, 2017, File No. 001-11590.
- Exhibit 3.6 — Certificate of Elimination of Series A Participating Cumulative Preferred Stock of Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 3.6 to our Annual Report on Form 10-K for the year ended December 31, 2017, File No. 001-11590.
- Exhibit 4.1 — Note Agreement dated October 18, 2005, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management, Inc., relating to the private placement of Chesapeake Utilities Corporation's 5.5% Senior Notes due 2020, is incorporated herein by reference to Exhibit 4.1 of our Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-11590.
- Exhibit 4.2 — Note Agreement dated October 31, 2008, among Chesapeake Utilities Corporation, as issuer, General American Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 5.93% Senior Notes due 2023.†
- Exhibit 4.3 — Note Agreement dated June 29, 2010, among Chesapeake Utilities Corporation, as issuer, Metropolitan Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 5.68% Senior Notes due 2026 and Chesapeake Utilities Corporation's 6.43% Senior Notes due 2028.†
- Exhibit 4.4 — Note Agreement dated September 5, 2013, among Chesapeake Utilities Corporation, as issuer, and certain note holders, relating to the private placement of Chesapeake Utilities Corporation's 3.73% Senior Notes due 2028 and Chesapeake Utilities Corporation's 3.88% Senior Notes due 2029.†
- Exhibit 4.5 — Form of Indenture of Mortgage and Deed of Trust dated September 1, 1942, between Florida Public Utilities Company and the trustee, for the First Mortgage Bonds, is incorporated herein by reference to Exhibit 7-A of Florida Public Utilities Company's Registration No. 2-6087.

- Exhibit 4.6 Seventeenth Supplemental Indenture dated April 12, 2011, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guarantees the payment and performance obligations of Florida Public Utilities Company under the Indenture, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, File No. 001-11590.
- Exhibit 4.7 Sixteenth Supplemental Indenture dated December 1, 2009, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guaranteed the secured First Mortgage Bonds of Florida Public Utilities Company under the Merger Agreement, is incorporated herein by reference to Exhibit 4.9 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
- Exhibit 4.8 Thirteenth Supplemental Indenture dated June 1, 1992, pursuant to which Florida Public Utilities, on May 1, 1992, privately placed $8,000,000 of its 9.08% First Mortgage Bonds due 2022, is incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 1992.
- Exhibit 4.9 Private Shelf Agreement dated October 8, 2015, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management Inc., relating to the private placement of Chesapeake Utilities Corporation's 3.25% Senior Notes due 2032 and the sale of other Chesapeake Utilities Corporation unsecured Senior Notes from time to time, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2015, File No. 001-11590.
- Exhibit 4.10 First Amendment to Private Shelf Agreement dated September 14, 2018, between Chesapeake Utilities Corporation, as issuer, and PGIM, Inc. (formerly known as Prudential Investment Management, Inc.), and other purchasers that may become party thereto. †
- Exhibit 4.11 Master Note Agreement dated March 2, 2017, among Chesapeake Utilities Corporation, as issuer, NYL Investors LLC, and other certain note holders that may become party thereto from time to time relating to the private placement of Chesapeake Utilities Corporation's 3.48% Senior Notes due 2038 and Chesapeake Utilities Corporation's 3.58% Senior Notes due 2038. †
- Exhibit 10.1* Chesapeake Utilities Corporation Cash Bonus Incentive Plan, effective January 1, 2015, is incorporated herein by reference to our Proxy Statement dated March 31, 2015, in connection with our Annual Meeting held on May 6, 2015, File No. 001-11590.
- Exhibit 10.2* Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan, effective May 2, 2013 is incorporated herein by reference to our Proxy Statement dated March 29, 2013 in connection with our Annual Meeting held on May 2, 2013, File No. 001-11590.
- Exhibit 10.3* Non-Qualified Deferred Compensation Plan, effective January 1, 2014, is incorporated herein by reference to Exhibit 10.8 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
- Exhibit 10.4* Executive Employment Agreement dated January 14, 2011, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
- Exhibit 10.5* Amendment to Executive Employment Agreement effective January 1, 2014, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K filed January 14, 2014, File No. 001-11590.
- Exhibit 10.6* Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.9 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
- Exhibit 10.7* Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.10 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
- Exhibit 10.8* Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Elaine B. Bittner, incorporated herein by reference to Exhibit 10.11 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.

- Exhibit 10.9* Executive Employment Agreement dated January 1, 2015, between Chesapeake Utilities Corporation and Jeffry M. Householder, is incorporated herein by reference to Exhibit 10.15 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
- Exhibit 10.10* Form of Performance Share Agreement, effective January 7, 2014 for the period 2014 to 2016, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, and Jeffry M. Householder is incorporated herein by reference to Exhibit 10.18 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
- Exhibit 10.11* Form of Performance Share Agreement, effective January 13, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner and Jeffry M. Householder, is incorporated herein by reference to Exhibit 10.19 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
- Exhibit 10.12* Form of Performance Share Agreement, dated March 6, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and James F. Moriarty is incorporated herein by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the year ended September 30, 2015, File No. 001-11590.
- Exhibit 10.13* Form of Performance Share Agreement, dated January 12, 2016 for the period 2016 to 2018, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder and James F. Moriarty, is incorporated herein by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2015, File No. 001-11590.
- Exhibit 10.14* Chesapeake Utilities Corporation Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.27 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
- Exhibit 10.15* First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Plan as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.30 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
- Exhibit 10.16 Revolving Credit Agreement dated October 8, 2015, between Chesapeake Utilities Corporation and PNC Bank, National Association, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada and Wells Fargo Bank, National Association as lenders, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2015, File No. 001-11590.
- Exhibit 10.17 First Amendment dated February 25, 2016 to the Revolving Credit Agreement dated October 8, 2015, between Chesapeake Utilities Corporation and PNC Bank, National Association, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada and Wells Fargo Bank, National Association as lenders, is incorporated herein by reference to Exhibit 10.24 of our Annual Report on Form 10-K for the year ended December 31, 2015, File No. 001-11590.
- Exhibit 10.18* Executive Employment Agreement dated May 10, 2016, between Chesapeake Utilities Corporation and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the year ended June 30, 2016, File No. 001-11590.
- Exhibit 10.19* Form of Performance Share Agreement, effective February 23, 2017 for the period 2017 to 2019, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder, and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the year ended June 30, 2017, File No. 001-11590.
- Exhibit 10.20 Credit Agreement, dated November 28, 2017, by and between Chesapeake Utilities Corporation and Branch Banking and Trust Company is filed herewith.

- Exhibit 10.21* Separation Agreement and Release, effective as of June 7, 2018, by and between Chesapeake Utilities Corporation and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on June 8, 2018, File No. 001-11590.

- Exhibit 10.22* Form of Performance Share Agreement, effective February 26, 2018 for the period 2018 to 2020, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Jeffry M. Householder and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, File No. 001-11590.

- Exhibit 10.23 Term Note dated December 21, 2018 issued by Chesapeake Utilities Corporation in favor of PNC Bank, National Association is filed herewith.

- Exhibit 10.24* Form of Performance Share Agreement, effective February 25, 2019 for the period January 01, 2019 to December 31, 2021, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and Jeffry M. Householder is filed herewith.

- Exhibit 10.25* Executive Employment Agreement dated February 25, 2019, between Chesapeake Utilities Corporation and Jeffry M. Householder, is filed herewith.

- Exhibit 10.26 Term Note dated January 31, 2019 issued by Chesapeake Utilities Corporation in favor of Branch Banking & Trust Company is filed herewith.

- Exhibit 21 Subsidiaries of the Registrant is filed herewith.

- Exhibit 23.1 Consent of Independent Registered Public Accounting Firm is filed herewith.

- Exhibit 31.1 Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), is filed herewith.

- Exhibit 31.2 Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), is filed herewith.

- Exhibit 32.1 Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, is filed herewith.

- Exhibit 32.2 Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, is filed herewith.

- Exhibit 101.INS XBRL Instance Document is filed herewith.

- Exhibit 101.SCH XBRL Taxonomy Extension Schema Document is filed herewith.

- Exhibit 101.CAL XBRL Taxonomy Extension Calculation Linkbase Document is filed herewith.

- Exhibit 101.DEF XBRL Taxonomy Extension Definition Linkbase Document is filed herewith.

- Exhibit 101.LAB XBRL Taxonomy Extension Label Linkbase Document is filed herewith.

- Exhibit 101.PRE XBRL Taxonomy Extension Presentation Linkbase Document is filed herewith.

* Management contract or compensatory plan or agreement.

† These agreements have not been filed herewith pursuant to Item 601(b)(4)(v) of Regulation S-K under the Securities Act of 1933, as amended. We hereby agree to furnish copies to the SEC upon request.

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, Chesapeake Utilities Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

By: /s/ JEFFRY M. HOUSEHOLDER
Jeffry M. Householder
President, Chief Executive Officer and Director
February 26, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ JEFFRY M. HOUSEHOLDER
Jeffry M. Householder
President, Chief Executive Officer and Director
February 26, 2019

/S/ BETH W. COOPER
Beth W. Cooper, Executive Vice President,
Chief Financial Officer,
and Assistant Corporate Secretary
(Principal Financial and Accounting Officer)
February 26, 2019

/S/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Chair of the Board and Director
February 26, 2019

/S/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
February 26, 2019

/S/ EUGENE H. BAYARD, ESQ
Eugene H. Bayard, Esq., Director
February 26, 2019

/S/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
February 26, 2019

/S/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
February 26, 2019

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters, Director
February 26, 2019

/S/ RONALD G. FORSYTHE, JR.
Dr. Ronald G. Forsythe, Jr., Director
February 26, 2019

/S/ CALVERT A. MORGAN, JR.
Calvert A. Morgan, Jr., Director
February 26, 2019

/S/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
February 26, 2019

/S/ DIANNA F. MORGAN
Dianna F. Morgan, Director
February 26, 2019

Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions: Charged to Income	Additions: Other Accounts (1)	Deductions (2)	Balance at End of Year
(In thousands)					
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
2018	**$ 936**	**$ 1,157**	**$ 136**	**$ (1,121)**	**$ 1,108**
2017	909	602	337	(912)	936
2016	909	985	340	(1,325)	909

(1) Recoveries.
(2) Uncollectible accounts charged off.

CORPORATE INFORMATION

CORPORATE OFFICE

909 Silver Lake Boulevard
Dover, DE 19904
Telephone: 302.734.6799
Website: ***www.chpk.com***

ANNUAL MEETING

The Annual Meeting of Stockholders will be held on Wednesday, May 8, 2019 at 9:00 a.m. in the du Barry Room, Hotel du Pont; 42 W. 11th Street; Wilmington, DE.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company, N.A.
c/o Chesapeake Utilities Corporation
P.O. Box 505000
Louisville, KY 40233-5000
Telephone (toll-free) 877.498.8865
Website: ***www.computershare.com/investor***

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

The Dividend Reinvestment and Direct Stock Purchase Plan provides flexible investment options for those who wish to invest in the Company. Common stock holders can have their dividends automatically reinvested to purchase additional shares directly through the Plan and/or send in additional optional cash investments at any time to increase their holdings. New investors can purchase shares directly through the Plan. For more information, please contact the Company's transfer agent (Computershare) as stated above.

ANALYST INFORMATION

Beth W. Cooper
Executive Vice President and Chief Financial Officer
Telephone: 302.734.6799
bcooper@chpk.com

Thomas E. Mahn
Vice President and Treasurer
Telephone: 302.734.6799
tmahn@chpk.com

COMMON STOCK AND DIVIDEND INFORMATION

CPK LISTED NYSE

NYSE: CPK

Chesapeake Utilities Corporation's common stock is traded on the New York Stock Exchange under the symbol **CPK**.

QUARTER ENDED 2018	PRICE RANGE HIGH	LOW	CLOSE	DIVIDENDS DECLARED PER SHARE*
March 31	$78.95	$63.35	$70.35	$0.3250
June 30	$80.90	$69.15	$79.95	$0.3700
September 30	$90.90	$79.10	$83.90	$0.3700
December 31	$93.40	$77.20	$81.30	$0.3700

QUARTER ENDED 2017	PRICE RANGE HIGH	LOW	CLOSE	DIVIDENDS DECLARED PER SHARE*
March 31	$70.70	$63.00	$69.20	$0.3050
June 30	$77.75	$68.65	$74.95	$0.3250
September 30	$81.95	$74.80	$78.25	$0.3250
December 31	$86.35	$75.00	$78.55	$0.3250

**Declaration of dividends is at the discretion of the Board of Directors. Dividends in 2018 and 2017 were paid quarterly.*

PUBLIC INFORMATION AND SEC FILINGS

Our latest news and filings with the Securities and Exchange Commission (SEC), including Forms 10-K, 10-Q and 8-K are available to view or request a printed copy, free of charge, at our website, ***www.chpk.com***.

If you wish to request a printed copy of any of the Company's publications by mail, please send your written request to Investor Relations below.

INVESTOR RELATIONS/SHAREHOLDER SERVICES

Heidi W. Watkins
Shareholder Services Manager
Telephone (toll free): 888.742.5275
hwatkins@chpk.com