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, 2017

☐ **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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments 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 "accelerated filer," "large 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	☐	(Do not check if a smaller reporting company"	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, 2017, the last business day of its most recently completed second fiscal quarter, based on the last trade price on that date, as reported by the New York Stock Exchange, was approximately $1.2 billion.

The number of shares of Chesapeake Utilities Corporation's common stock outstanding as of February 20, 2018 was 16,344,442.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2018 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, 2017.

CHESAPEAKE UTILITIES CORPORATION

FORM 10-K

YEAR ENDED DECEMBER 31, 2017

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GLOSSARY OF DEFINITIONS

AFUDC: Allowance for funds used during construction

Amendment: The Second Amendment to the Rights Agreement, which was executed on February 27, 2018, and which has the effect of terminating the Rights Agreement at 5:00 P.M., New York City time on that date.

ARM: ARM Energy Management, LLC, a natural gas supply and supply management company servicing commercial and industrial customers in Western Pennsylvania, which sold certain assets to PESCO in August 2017

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

Aspire Energy: Aspire Energy of Ohio, LLC, a wholly-owned subsidiary of Chesapeake Utilities, into which Gatherco merged on April 1, 2015

AutoGas: Alliance AutoGas, a national consortium of companies providing an industry-leading complete program for fleets interested in shifting from gasoline to clean-burning propane, of which Sharp is a member

CDD: Cooling degree-day, which is the measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit

Central Gas: Central Gas Company of Okeechobee, Incorporated, a propane distribution provider in Southeast Florida, which sold certain assets to Flo-gas in December 2017

CGC: Consumer Gas Cooperative, an Ohio natural gas cooperative

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

Chesapeake Pension Plan: A defined benefit pension plan sponsored by Chesapeake Utilities

Chesapeake Postretirement Plan: An unfunded postretirement health care and life insurance plan sponsored by Chesapeake Utilities

Chesapeake SERP: An unfunded supplemental executive retirement pension plan sponsored by Chesapeake Utilities

Chesapeake Service Company: Chesapeake Service Company, a wholly-owned subsidiary of Chesapeake Utilities and the parent company of Skipjack, CIC and ESRE

Chipola: Chipola Propane Gas Company, Inc., a propane distribution service provider in Northwest Florida, which sold certain assets to Flo-gas in August 2017

CHP: Combined heat and power plant

CIAC: Contributions from customers that are used to construct facilities

CIC: Chesapeake Investment Company, a wholly-owned subsidiary of Chesapeake Service Company, which is an investment company incorporated in Delaware

Columbia Gas: Columbia Gas Transmission, LLC, an unaffiliated interstate pipeline interconnected with Eastern Shore's pipeline

Columbia Gas of Ohio: An unaffiliated local distribution company based in Ohio

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

CP: Certificate of Public Convenience and Necessity

Credit Agreement: The Credit Agreement dated October 8, 2015, among Chesapeake Utilities and the Lenders related to the Revolver

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

Delaware Division: Chesapeake Utilities' natural gas distribution operation serving customers in Delaware

Delmarva Peninsula: A peninsula on the east coast of the United States of America occupied by Delaware and portions of Maryland and Virginia

Delmarva Peninsula natural gas distribution: Chesapeake Utilities' natural gas distribution operations, which includes the Delaware Division, Chesapeake Utilities' Maryland division, and Sandpiper

Dodd-Frank Act: The Dodd-Frank Wall Street Reform and Consumer Protection Act

DNREC: Delaware Department of Natural Resources and Environmental Control

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 interstate natural gas transmission subsidiary of Chesapeake Utilities

EGWIC: Eastern Gas & Water Investment Company, LLC, an affiliate of Eastern Shore Gas Company

Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake OnSight Services, LLC, which owns and operates a CHP plant on Amelia Island, Florida, that supplies electricity to FPU and industrial steam to Rayonier

EPA: United States Environmental Protection Agency

ESG: Eastern Shore Gas Company and its affiliates

ESRE: Eastern Shore Real Estate, Inc., a wholly-owned subsidiary of Chesapeake Utilities that owns and leases office buildings in Delaware and Maryland to divisions and subsidiaries of Chesapeake Utilities

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission, an independent agency of the United States government that regulates the interstate transmission of electricity, natural gas, and oil

FDEP: Florida Department of Environmental Protection

FDOT: Florida Department of Transportation

FGT: Florida Gas Transmission Company

Flo-gas: Flo-gas Corporation, a wholly-owned subsidiary of FPU

Florida Division: Chesapeake Utilities' natural gas distribution operation serving customers in Florida

Fort Meade: Fort Meade natural gas division of FPU

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

FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake Utilities

FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake Utilities

GAAP: Accounting principles generally accepted in the United States of America

Gatherco: Gatherco, Inc., a corporation that merged with and into Aspire Energy on April 1, 2015

GRIP: The Gas Reliability Infrastructure Program, a natural gas pipeline replacement program in Florida, pursuant to which we collect a surcharge from certain of our customers to recover capital and other program-related costs associated with the replacement of qualifying distribution mains and services

GSR: Gas Service Rates

Gulf Power: Gulf Power Company, an unaffiliated electric company which supplies electricity to FPU

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

HDD: Heating degree-day, which is a measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is below 65 degrees Fahrenheit

ICE: Intercontinental Exchange is an electronic trading platform

IGC: Indiantown Gas Company, a division of FPU

IRS: Internal Revenue Service

JEA: The unaffiliated community-owned utility located in Jacksonville, Florida, formerly known as Jacksonville Electric Authority

Lenders: PNC, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada, and Wells Fargo Bank, National Association, which are collectively the lenders that entered into the Credit Agreement with Chesapeake Utilities

MDE: Maryland Department of Environment

MetLife: MetLife Investment Advisors, an institutional debt investment management firm, with which we entered into the MetLife Shelf Agreement

MetLife Shelf Agreement: An agreement entered into by Chesapeake Utilities and MetLife pursuant to which Chesapeake Utilities may request that MetLife purchase, through March 2, 2020, up to $150.0 million of unsecured senior debt at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance

MetLife Shelf Notes: Unsecured senior promissory notes issuable under the MetLife 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: Fair value (mark-to-market) accounting required for derivatives in accordance with ASC 815

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

Non-Qualified Deferred Compensation Plan: A non-qualified, deferred compensation plan under which certain of our executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive salaries, cash bonuses, executive performance shares and directors' retainers

NYL: New York Life Investors LLC, an institutional debt investment management firm, with which we entered into the NYL Shelf Agreement

NYL Shelf Agreement: An agreement entered into by Chesapeake Utilities and NYL pursuant to which Chesapeake Utilities may request that NYL purchase, through March 2, 2020, up to $100.0 million of unsecured senior debt at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance

NYL Shelf Notes: Unsecured senior promissory notes issuable under the NYL Shelf Agreement

NYSE: New York Stock Exchange

OPT Service: Off Peak ≤ 30 or ≤ 90 Firm Transportation Service, a tariff associated with Eastern Shore's firm transportation service that allows Eastern Shore to not schedule service for up to 30 or 90 days during the peak months of November through April each year

OTC: Over-the-counter

Peninsula Pipeline: Peninsula Pipeline Company, Inc., Chesapeake Utilities' wholly-owned Florida intrastate pipeline subsidiary

Peoples Gas: The Peoples Gas System division of Tampa Electric Company, an unaffiliated utility in Florida that has a joint pipeline with Peninsula Pipeline

PESCO: Peninsula Energy Services Company, Inc., Chesapeake Utilities' wholly-owned natural gas marketing subsidiary

PNC: PNC Bank, National Association, the administrative agent and primary lender for our Revolver

Proxy Statement: Chesapeake Utilities' definitive Proxy Statement to be filed no later than March 31, 2018, in connection with our Annual Meeting to be held on or about May 9, 2018

Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the Prudential Shelf Agreement

Prudential Shelf Agreement: An agreement entered into by Chesapeake Utilities and Prudential pursuant to which Chesapeake Utilities may request that Prudential purchase, through October 7, 2018, up to $150.0 million of Prudential Shelf Notes at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance

Prudential Shelf Notes: Unsecured senior promissory notes issuable under the Prudential Shelf Agreement

PSC: Public Service Commission, which is the state agency that regulates the rates and/or services provided by Chesapeake Utilities' natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida

RAP: Remedial Action Plan, which is a plan that outlines the procedures taken or being considered in removing contaminants from a MGP formerly owned by Chesapeake Utilities or FPU

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

Retirement Savings Plan: Chesapeake Utilities' qualified 401(k) retirement savings plan

Revolver: Our unsecured revolving credit facility with the Lenders

Rights Agreement: The Rights Agreement by and between the Company and BankBoston, N.A., dated August 20, 1999, as amended by that certain First Amendment to Rights Agreement by and between the Company and Computershare Trust Company N.A., as successor rights agent, dated September 12, 2008

Sandpiper: Sandpiper Energy, Inc., Chesapeake Utilities' wholly-owned subsidiary, which provides a tariff-based distribution service to customers in Worcester County, Maryland

Sanford Group: FPU and other responsible parties involved with the Sanford MGP site

SCO: Standard Choice Offer, a program offered by Columbia Gas of Ohio in which PESCO was selected as a natural gas supplier pursuant to a competitive auction to serve a pool of customers within Columbia Gas of Ohio's service territory from April 2016 through March 2017

SEC: Securities and Exchange Commission

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

Sharp: Sharp Energy, Inc., Chesapeake Utilities' wholly-owned propane distribution subsidiary

Sharpgas: Sharpgas, Inc., a subsidiary of Sharp

SICP: 2013 Stock and Incentive Compensation Plan

SIR: A system improvement rate adder designed to fund system expansion costs within the city limits of Ocean City, Maryland

Skipjack: Skipjack, Inc., a wholly-owned subsidiary of Chesapeake Service Company that owns and leases office buildings in Delaware and Maryland to affiliates of Chesapeake Utilities

S&P 500 Index: Standard & Poor's 500 Index, a stock market index based on the market capitalization of 500 leading companies, which is intended to represent the overall composition of the economy

TCJA: Tax Cuts and Jobs Act of 2017, legislation passed by Congress and signed into law by the President on December 22, 2017, which among other things reduced the corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018

TETLP: Texas Eastern Transmission, LP, an interstate pipeline interconnected with Eastern Shore's pipeline

Third Participation Agreement: An agreement signed by FPU and the Sanford Group, which provides for the funding of the final remedy approved by the EPA for the property owned by FPU in Sanford, Florida

Transco: Transcontinental Gas Pipe Line Company, LLC, an interstate pipeline interconnected with Eastern Shore's pipeline

Xeron: Xeron, Inc., an inactive subsidiary of Chesapeake Utilities, which previously engaged in propane and crude oil trading

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 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 (including deregulation) 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, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters 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;
- 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;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- long-term global climate change, which could adversely affect customer demand or cause extreme weather conditions that disrupt the Company's operations;
- 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 ability to establish new, and maintain key, supply sources;
- 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 and in 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 merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger; acquisition or divestiture, and the success of the business following a 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 the Patient Protection and Affordable Care Act;
- the ability to continue to hire, train and retain appropriately qualified personnel;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- the timing and success of technological improvements; and
- risks related to cyber-attacks or cyber-terrorism that could disrupt our business operations or result in failure of information technology systems.

ITEM 1. BUSINESS.

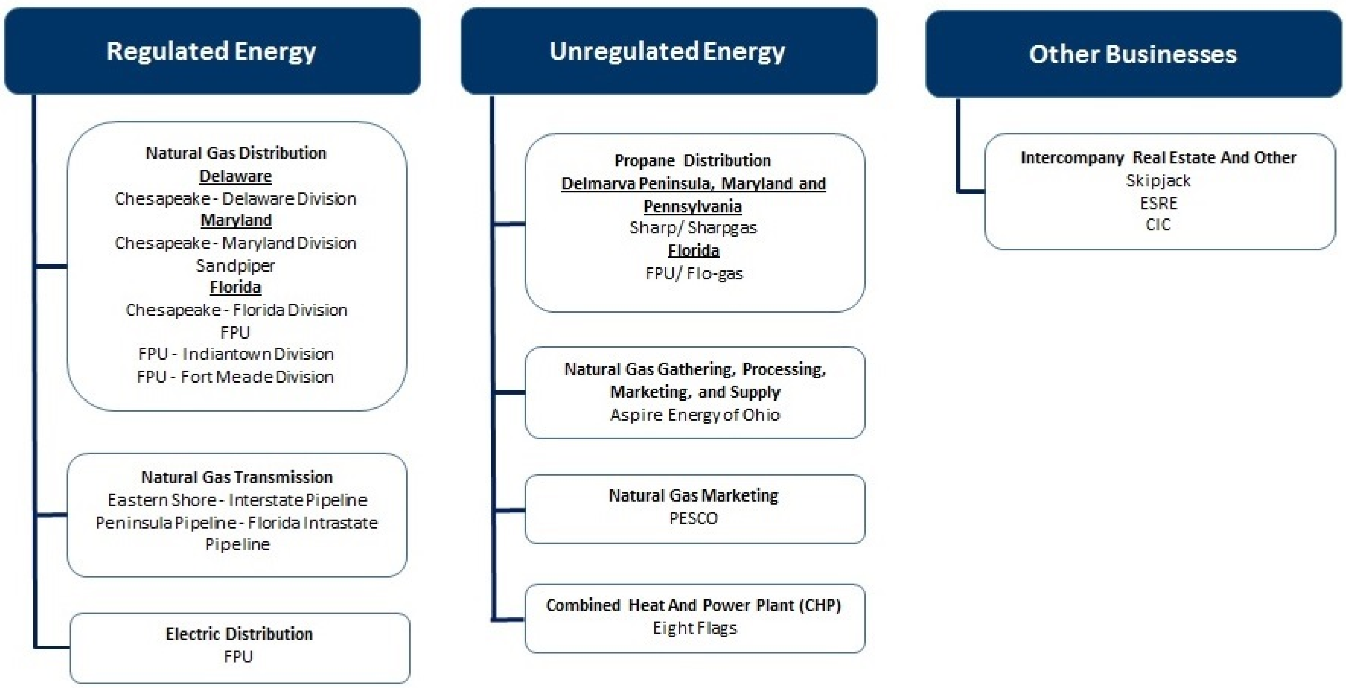
CORPORATE OVERVIEW

Chesapeake Utilities Corporation is a Delaware corporation formed in 1947. We are a diversified energy company engaged, through our operating divisions and subsidiaries, in various energy and other businesses. We operate primarily on the Delmarva Peninsula and in Florida, Pennsylvania and Ohio and provide natural gas distribution, transmission, supply, gathering, processing and marketing; electric distribution and generation; propane distribution; steam generation; and other energy-related services.

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."

The following chart shows our principal business structure by segment and other businesses:



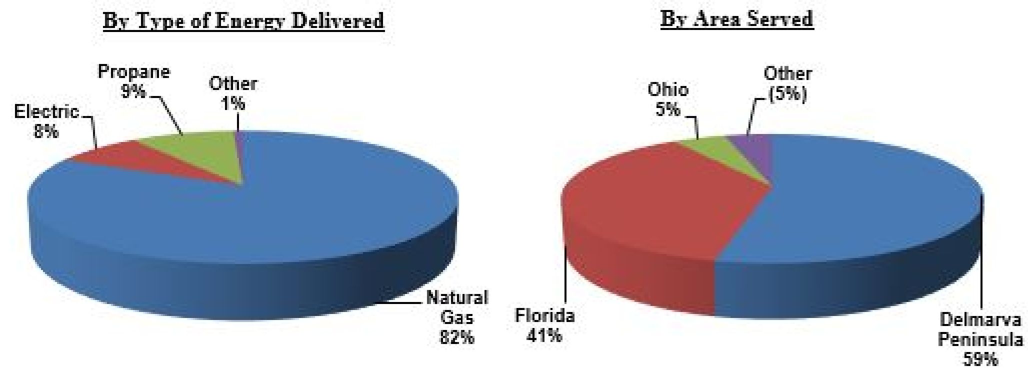
The following table shows operating income for the year ended December 31, 2017, and total assets as of December 31, 2017, for our operating segments and other businesses and eliminations:

(dollars in thousands)		Operating Income		Total Assets
Regulated Energy	$	73,160	$	1,121,673
Unregulated Energy		12,477		261,541
Other businesses and eliminations		206		34,220
Total	$	85,843	$	1,417,434

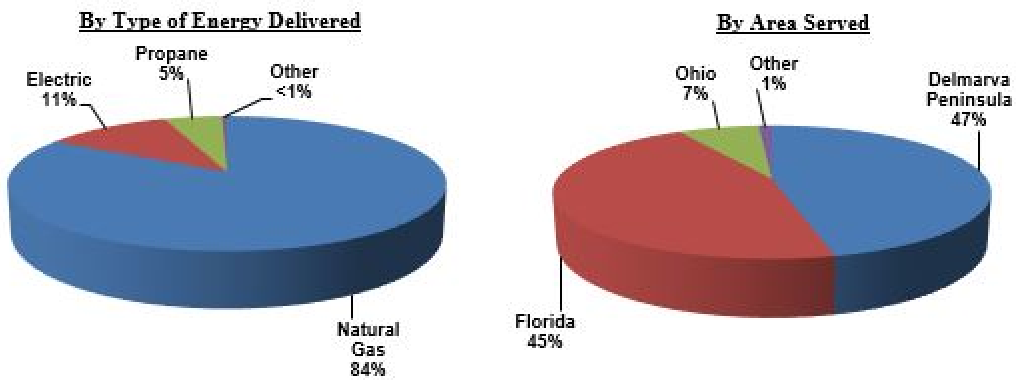
Additional financial information by business segment is set forth in *Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operation,* and *Item 8, Financial Statements and Supplementary Data* (see Note 5, *Segment Information,* in the consolidated financial statements).

The following charts present operating income by type of energy delivered and areas served for the year ended December 31, 2017 and average investment by type of energy delivered and areas served as of December 31, 2017.

Operating Income by Energy Delivered and Area Served



Average Investment by Energy Delivered and Area Served [1]



(1) Average investment is based on investments for the 13-month period ended December 31, 2017.

REGULATED ENERGY

Regulated Energy is our largest segment and consists of: (i) our natural gas distribution operations in Delaware, Maryland and Florida; (ii) our electric distribution operations in Florida; and (iii) our natural gas transmission operations on the Delmarva Peninsula and in Florida. All operations in this segment are regulated, as to their rates and service, by the PSC having jurisdiction in each state in which we operate or by the FERC in the case of Eastern Shore. Our natural gas and electric distribution operations are local distribution utilities and generate revenues based on tariff rates approved by the PSC of each state in which we operate. The PSCs have also authorized our utilities to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. Some of our customers in Maryland are, and will continue to be, served with propane through our underground propane distribution system under PSC-approved tariff rates until we complete the conversion of the system and these customers to natural gas. These customers are included in the Delmarva Peninsula natural gas distribution operation's results and customer statistics.

Eastern Shore generates revenues based upon the FERC-approved tariff rates. Eastern Shore is also authorized by the FERC to negotiate rates with its customers above or below the FERC-approved tariff rates. Peninsula Pipeline, our Florida intrastate pipeline subsidiary, is subject to regulation by the Florida PSC and has negotiated contracts with customers, including certain affiliates. Our rates are designed to provide the opportunity to generate revenues to recover all prudently incurred costs and provide a return on our rate base that is sufficient to pay interest on debt and a reasonable return for our stockholders. Each of our utilities has a rate base, which generally consists of the original cost of the utility's plant less related accumulated depreciation, working capital and certain other assets. In certain jurisdictions, the rate base may also include deferred income tax liabilities and other additions or deductions.

The natural gas commodity market for Chesapeake Utilities' Florida Division and FPU’s Indiantown division is deregulated. Accordingly, marketers, rather than a traditional utility, sell natural gas to end-use customers in those jurisdictions. For all of our other local distribution utilities, we have fuel cost recovery mechanisms authorized by the PSCs that allow us to periodically adjust fuel rates to reflect changes in the wholesale cost of natural gas and electricity and to ensure we recover all of the costs prudently incurred in purchasing natural gas and electricity for our 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, 2017:

	Delmarva Natural Gas Distribution		Florida Natural Gas Distribution [2]		FPU Electric Distribution	
Operating Revenues *(in thousands)*						
Residential	$ 57,365	57%	$ 38,703	38 %	$ 44,082	53 %
Commercial	31,585	32%	36,039	36 %	41,141	50 %
Industrial	7,619	8%	28,182	28 %	3,561	4 %
Other [1]	3,504	3%	(1,495)	(2)%	(5,918)	(7)%
Total Operating revenues	$ 100,073	100%	$ 101,429	100 %	$ 82,866	100 %
Volumes *(in Dts for natural gas/MWHs for electric)*						
Residential	3,368,603	28%	1,690,983	6 %	291,510	46 %
Commercial	3,274,975	28%	7,019,970	26 %	304,235	48 %
Industrial	5,125,633	43%	16,105,084	60 %	27,380	4 %
Other	95,415	1%	1,875,761	8 %	7,511	2 %
Total Volumes	11,864,626	100%	26,691,798	100 %	630,636	100 %
Average Number of Customers [4]						
Residential	68,699	91%	70,206	90 %	24,574	77 %
Commercial	6,845	9%	5,475	7 %	7,450	23 %
Industrial	147	—%	2,157	3 %	2	— %
Other	5	—%	3	— %	—	— %
Total Average Customers	75,696	100%	77,841	100 %	32,026	100 %

[1] Operating Revenues from "Other" sources include 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' Florida Division, FPU and FPU's Indiantown and Fort Meade divisions.
[3] Average number of customers is based on twelve-month average for the year ended December 31, 2017.

The following table presents operating revenues and design day capacity for Eastern Shore for the year ended December 31, 2017 and contracted firm transportation capacity at December 31, 2017:

	Eastern Shore	
Operating Revenues *(in thousands)*		
Local distribution companies - affiliated [1]	$ 18,350	32 %
Local distribution companies - non-affiliated	22,782	39 %
Commercial and industrial	20,485	35 %
Other [2]	(3,847)	(6)%
Total Operating Revenues	$ 57,770	100 %
Contracted firm transportation capacity *(in Dts/d)*		
Local distribution companies - affiliated	100,652	43 %
Local distribution companies - non-affiliated	66,182	28 %
Commercial and industrial	67,923	29 %
Total	234,757	100 %
Design day capacity *(in Dts/d)*	234,757	100 %

[1] Eastern Shore's service to our local distribution affiliates is based on FERC-approved rates and is an integral component of the cost associated with providing natural gas supplies for those affiliates. We eliminate operating revenues of Eastern Shore 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.

Peninsula Pipeline contracts with both affiliated and non-affiliated customers to provide firm transportation service. For the year ended December 31, 2017, operating revenues of Peninsula Pipeline were $7.2 million, of which $4.5 million was related to service to our affiliates, FPU and Eight Flags, under contracts which were previously approved by the Florida PSC. Peninsula Pipeline's operating revenues from FPU and Eight Flags are eliminated against the cost of sales in our consolidated financial information; FPU, however, includes this amount in its purchased fuel cost and recovers it through the fuel cost recovery mechanism.

As of December 31, 2017, our investments in our regulated operations were as follows: $136.5 million for Delmarva Peninsula natural gas distribution; $316.0 million for Florida natural gas and electric distribution; and $250.1 million for natural gas transmission.

Weather

Revenues from our residential and commercial sales are affected by seasonal variations in weather conditions, which directly influence the volume of natural gas and electricity sold and delivered. Specifically, customer demand substantially increases during the winter months, when natural gas and electricity are used for heating. For electricity, customer demand also increases during the summer months, when electricity is used for cooling. We measure the relative impact of weather by using a degree-day methodology accepted by the utility industry. Degree-day data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature. Normal heating and cooling degree-days are based on the most recent 10-year average.

Our Maryland division and Sandpiper's rates include a weather normalization adjustment for residential heating and smaller commercial heating customers. A weather normalization adjustment is a billing adjustment mechanism (or "decoupled" rate mechanism) that is designed to eliminate the effect of deviations from average seasonal temperatures on utility net revenues. Sandpiper received approval from the Maryland PSC to include in its rates a revenue normalization mechanism for residential heating and smaller commercial heating customers in 2016.

We do not currently have any weather or revenue normalization or "decoupled" rate mechanisms for our other local distribution utilities.

Regulatory Matters

The following table identifies the key regulatory agencies and highlights the most recent base rate proceeding information for each of our major utilities:

	Chesapeake Utilities - Delaware Division	Chesapeake Utilities - Florida Division	FPU Natural Gas	FPU Electric	Chesapeake Utilities - Maryland Division	Eastern Shore	Sandpiper
Regulatory Agency:	**Delaware PSC**	**Florida PSC**	**Florida PSC**	**Florida PSC**	**Maryland PSC**	**FERC**	**Maryland PSC**
Commission Structure:	5 commissioners	5 commissioners	5 commissioners	5 commissioners	5 commissioners	5 commissioners	5 commissioners
	Part-Time	Full-Time	Full-Time	Full-Time	Full-Time	Full-Time	Full-Time
	Gubernatorial Appointment	Gubernatorial Appointment	Gubernatorial Appointment	Gubernatorial Appointment	Gubernatorial Appointment	Presidential Appointment	Gubernatorial Appointment
Base Rate Proceeding:							
Delay in collection of rates subsequent to filing application	60 days	90 days	90 days	90 days	180 days	Up to 180 days	180 days
Application date associated with the most recent permanent rates	12/21/2015	07/14/2009	12/17/2008	07/03/2017	05/01/2006	1/27/2017	12/02/2015
Effective date of permanent rates	01/01/2017	01/14/2010	01/14/2010[1]	01/03/2018	12/01/2007	08/01/2017[2]	12/01/2017
Annual rate increase approved[6]	$2,250,000	$2,536,300	$7,969,000	$1,558,050	$648,000	$9,800,000[2]	N/A[7]
Rate of return approved[6]	9.75% [3]	10.80%[3]	10.85%[3]	10.25%[3], [4]	10.75%[3]	Not Stated[2]	Not Stated [5]

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

(2) Eastern Shore filed an uncontested settlement agreement with the FERC in December 2017. FERC approved the settlement agreement by letter order on February 28, 2018. The order will be deemed final upon the expiration of the right to rehearing on March 30, 2018.

(3) Allowed after-tax return on equity.

(4) 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.

(5) The terms of the agreement include revenue neutral rates for the first year, followed by a schedule of rate reductions in subsequent years based upon the projected rate of propane to natural gas conversions.

(6) 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 18, *Rates and Other Regulatory Activities* and Note 11, *Income Taxes* in the consolidated financial statements) for further discussion on the impact of this legislation on our regulated businesses.

(7)The Maryland PSC approved a declining return on equity that will result in a decline in our rates.

In addition to the base rates approved by the PSCs, certain of our local distribution utilities have additional surcharge mechanisms that were separately approved by their respective PSC. The most notable surcharge mechanisms include Delaware's surcharge to increase the availability of natural gas in portions of eastern Sussex County, Delaware; Maryland's surcharge designed to recover the costs associated with conversions to natural gas and to improve infrastructure in Worcester County, Maryland; and Florida's GRIP surcharge designed to recover capital and other costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains.

TCJA

At the end of December 2017, the United States Congress passed and the President signed into law, the TCJA, which is effective beginning with the 2018 tax year. Among other things, the TCJA substantially reduces the corporate income tax rate to 21 percent, effective January 1, 2018. Each state PSC, with jurisdiction over the areas that we serve, has issued, or is in the process of issuing, requests for information or orders directing utilities to make filings estimating the impacts of the TCJA on their respective costs to serve and to propose how the tax law changes are to be reflected in rates. We will comply with these orders and will make any necessary changes, as directed by the applicable PSC. The FERC has not yet issued any procedural orders on this matter; however, the settlement agreement that we filed with the FERC in December 2017 outlined the procedures and proposed customer rates in the event of tax reform. We believe that the ultimate resolution of these matters will not have a material impact on our financial position, operating results or cash flows.

See *Item 8, Financial Statements and Supplementary Data* (Note 11, *Income Taxes*, and Note 18, *Rates and Other Regulatory Activities*, in the consolidated financial statements), for more information.

Competition

Our natural gas and electric distribution operations and our natural gas transmission operations compete with other forms of energy, including oil, propane and renewables. The principal competitive factors are price and, to a lesser extent, accessibility. Our natural gas distribution operations have several large industrial customers that are able to use fuel oil or propane as an alternative to natural gas. When oil or propane prices decline, these interruptible customers may convert to an alternative fuel source to satisfy their fuel requirements, and our sales volumes may decline. To address the uncertainty of alternative fuel prices, we use flexible pricing arrangements on both the supply and sales sides of our business to compete with alternative fuel price fluctuations.

Large industrial natural gas customers may be able to bypass our distribution and transmission systems and make direct connections with "upstream" interstate transmission pipelines when such connections are economically feasible. Certain large industrial electric customers may be capable of generating electricity for their own consumption. Although the risk of bypassing our systems is not considered significant, we may adjust services and rates for these customers to retain their business in certain situations.

Supplies, Transmission and Storage

We believe that the availability of supply and transmission of natural gas is adequate under existing arrangements to meet the needs of our customers.

Our Delaware, Maryland and Sandpiper divisions use their firm transportation resources to meet a significant percentage of their projected demand requirements. They purchase firm natural gas supplies to meet those projected requirements with purchases of base load, daily spot supplies and storage service. They have both firm and interruptible transportation service contracts with four interstate "open access" pipeline companies (Eastern Shore, Transco, Columbia Gas and TETLP) in order to meet customer demand. Their distribution system is directly interconnected with Eastern Shore's pipeline, which is directly interconnected with the upstream pipelines of Transco, Columbia Gas and TETLP. The following table summarizes the firm transportation agreements for Delaware and Maryland divisions:

Division	Counterparty	Maximum Daily Firm Transportation Capacity (Dts)	Contract Expiration Date
Delaware	Eastern Shore	72,029	2018 - 2028
	Columbia Gas	10,960	2019 - 2020
	Transco	21,423	2018 - 2028
	TETLP	34,100	2027
Maryland	Eastern Shore	26,673	2018 - 2027
	Columbia Gas	4,200	2018 - 2019
	Transco	6,128	2018
	TETLP	15,900	2027

The Delaware and Maryland divisions also have the capability to use propane-air and liquefied natural gas peak-shaving equipment to supplement or displace natural gas purchases.

Our Delaware and Maryland divisions contract with our natural gas marketing subsidiary, PESCO, through an asset management agreement, to optimize their transportation and storage capacity and secure an adequate supply of natural gas. Pursuant to the three-year asset management agreement, the asset manager pays our divisions a fee, which our divisions share with their customers.

Sandpiper is a party to a capacity, supply and operating agreement with EGWIC to purchase propane, with a contract ending in May 2019. Sandpiper's current annual commitment is estimated at approximately 2.7 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. Sandpiper also has 1,950 Dts of maximum daily firm transportation capacity available from Eastern Shore through contracts expiring on various dates between 2018 and 2027.

The following table summarizes the firm transportation agreements for our Florida Division and FPU:

Division	Counterparty	Maximum Daily Firm Transportation Capacity (Dts)	Contract Expiration Date
Florida Division	Gulfstream [1]	10,000	2022
FPU	FGT	41,909 - 73,317	2020 - 2041
	Peninsula Pipeline	25,000 - 32,000	2033 - 2038
	Peoples Gas System	2,660	2024 - 2035
	Florida City Gas	300	2032

[1] 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.

FPU uses gas marketers and producers to procure all of its gas supplies to meet projected requirements. FPU also uses Peoples Gas to provide wholesale gas sales service in areas far from FPU's interconnections with FGT.

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 2018 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.

During 2017, FPU purchased wholesale electricity primarily from three main suppliers: JEA, Gulf Power and Eight Flags. As of January 2018, FPU purchases its wholesale electricity primarily from Gulf Power, FPL and Eight Flags. The following table summarizes the supply contracts for FPU:

Counterparty	Contracted Amount (MW)	Contract Expiration Date
Gulf Power	Full Requirement	2019
FPL	Full Requirement	2024
Eight Flags	21	2036
Rayonier	1.7 to 3.0	2036
WestRock Company	As-available	N/A

The Gulf Power contract provides generation and transmission service to the Northwest Florida service territory. The FPL contract provides generation and transmission service to the Northeast Florida service territory. The electricity purchased from Eight Flags, Rayonier and WestRock Company serves a portion of FPU's electric distribution customers' base load in Northeast Florida.

UNREGULATED ENERGY

Our Unregulated Energy segment provides: (i) propane distribution; (ii) natural gas marketing; (iii) unregulated natural gas supply, gathering and processing; (iv) electricity and steam generation; and (v) other unregulated energy-related services to customers. Revenues generated from this segment are not subject to any federal, state or local pricing regulations. Our businesses in this segment typically complement our regulated energy businesses based on the products and services they sell.

Propane Distribution

Our propane distribution operations sell propane to residential, commercial/industrial, and wholesale customers, including AutoGas customers, in Delmarva and southeastern Pennsylvania, through Sharp and Sharpgas, and in Florida through FPU and Flo-gas. Many of our propane distribution customers are "bulk delivery" customers. We make deliveries of propane to the bulk delivery customers as needed, based on the level of propane remaining in the tank located at the customer's premises. We invoice and record revenues for our bulk delivery service customers at the time of delivery, rather than upon customers' actual usage, since the customers typically own the propane gas in the tanks on their premises. We also have underground propane distribution systems serving various neighborhoods and communities. Such customers are billed monthly based on actual consumption, which is measured by meters installed on their premises. In Florida, we also offer metered propane distribution service to residential and commercial customers. We read the meters on such customers' tanks and bill customers monthly. As a member of AutoGas, Sharp and AutoGas install and support propane vehicle conversion systems for vehicle fleets. Sharp continues to convert fleets to bi-fuel propane-powered engines and provides onsite fueling infrastructure.

Propane Distribution - Operational Highlights

For the year ended December 31, 2017, operating revenues, volumes sold and average number of customers by customer class for our Delmarva Peninsula and Pennsylvania and Florida propane distribution operations were as follows:

	Delmarva Peninsula and Pennsylvania		Florida	
Operating Revenues *(in thousands)*				
Residential bulk	$ 21,051	28%	$ 6,123	28%
Residential metered	7,904	11%	4,735	22%
Commercial bulk	13,655	18%	5,104	23%
Commercial metered	—	—%	2,119	10%
Wholesale	24,667	33%	920	4%
AutoGas	2,318	3%	—	—%
Other [1]	5,033	7%	2,946	13%
Total Operating Revenues	$ 74,628	100%	$ 21,947	100%
Volumes *(in thousands of gallons)*				
Residential bulk	8,718	17%	1,433	23%
Residential metered	3,352	6%	893	14%
Commercial bulk	9,032	18%	2,371	37%
Commercial metered	—	—%	827	13%
Wholesale	24,463	48%	812	13%
AutoGas	2,159	4%	—	—%
Other	3,500	7%	—	—%
Total Volumes	51,224	100%	6,336	100%
Average Number of Customers [2]				
Residential bulk	25,452	66%	9,059	55%
Residential metered	8,669	23%	6,089	37%
Commercial bulk	4,166	11%	930	6%
Commercial metered	—	—%	278	2%
Wholesale	35	—%	8	—%
AutoGas	74	—%	—	—%
Total Average Customers	38,396	100%	16,364	100%

[1] Operating revenues from "Other" sources include revenues from energy-related merchandise; customer loyalty programs; delivery, service and appliance fees; and unbilled revenues.

[2] Average number of customer is based on twelve-month average for the year ended December 31, 2017.

Propane Distribution - Competition

We compete with several other propane distributors in our geographic markets, primarily on the basis of price and service. Our competitors generally include local outlets of national distributors and local independent distributors, whose proximity to customers entails lower costs to provide service. As an energy source, propane competes with home heating oil and electricity, which are typically more expensive (based on equivalent unit of heat value). Since natural gas has historically been less expensive than propane, propane is generally not utilized for home heating in geographic areas served by natural gas pipelines or distribution systems.

Propane Distribution - Supplies, Transportation and Storage

We purchase propane for our propane distribution operations primarily from suppliers, including major oil companies, and independent producers of natural gas liquids. Although supplies of propane from these and other sources are generally readily available for purchase, extreme market conditions, such as significant fluctuations in weather, closing of refineries and disruption in supply chains, could result in a reduction in available supplies.

Propane is transported by trucks and railroad cars from refineries, natural gas processing plants or pipeline terminals to bulk propane storage facilities that we own in Delaware, Maryland, Pennsylvania, Virginia and Florida. These bulk storage facilities have an aggregate capacity of approximately 6.8 million gallons. We then deliver propane from these storage facilities by truck to tanks located on our customers' premises.

Propane Distribution Weather

Revenues from our propane distribution sales activities are affected by seasonal variations in temperature and weather conditions. Weather conditions and their severity directly influence the volume of propane used by our metered customers or sold and delivered to our bulk customers, with demand increasing substantially 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.

Propane and Crude Oil Wholesale Marketing

Prior to its wind down in the second quarter of 2017, Xeron traded in short-term natural gas liquids and crude oil forward and futures contracts on the InterContinentalExchange, Inc. Xeron settled its purchases and sales financially, without taking physical delivery of the propane or crude oil.

Natural Gas Marketing

We provide natural gas supply and supply management services through PESCO to residential, commercial, industrial and wholesale customers. PESCO operates primarily in the Southeast, Mid-Atlantic and Appalachian Basin regions. The following table summarizes PESCO's operating revenues by region in 2017:

	Operating Revenues *(in thousands)*	% of Total
Southeast	$ 59,269	32%
Mid-Atlantic	87,241	47%
Appalachian Basin	38,009	21%
	$ 184,519	100%

PESCO competes with regulated utilities and other unregulated third-party marketers to sell natural gas supplies directly to commercial and industrial customers through competitively-priced contracts. PESCO does not currently own or operate any natural gas transmission or distribution assets. The gas that PESCO sells is delivered to retail or wholesale customers through affiliated and non-affiliated local distribution company systems and transmission pipelines. PESCO bills its customers directly or through the billing services of the regulated utilities that deliver the gas. In August 2017, PESCO acquired certain natural gas marketing assets of ARM. The acquired assets complement PESCO's current asset portfolio and expand our regional footprint and retail demand in a market where we have existing pipeline capacity and wholesale liquidity.

In 2017, PESCO entered into asset management agreements with our Delmarva Peninsula natural gas distribution operations to manage a portion of their natural gas transportation and storage capacity, which agreements were approved by the Delaware PSC with respect to our Delaware Division. The agreements were effective as of April 1, 2017, and each has a three-year term, expiring on March 31, 2020.

Unregulated Natural Gas Infrastructure Services

Aspire Energy is an unregulated natural gas infrastructure company that owns approximately 2,600 miles of pipeline systems in 40 counties throughout Ohio. The majority of Aspire Energy's margin is derived from long-term supply agreements with Columbia Gas of Ohio and CGC, which together serve more than 20,000 end-use customers. Aspire Energy primarily sources gas from 300 conventional producers and also provides gathering and processing services so that it can maintain quality and reliability for its wholesale markets.

For the twelve-month period ended December 31, 2017, Aspire Energy's operating revenues and deliveries by customer type were as follows:

	Operating revenues *(in thousands)*	Deliveries *(in Dts)*
Supply to Columbia Gas of Ohio	$ 11,827	2,264
Supply to CGC	10,507	1,345
Supply to Marketers - affiliated	4,027	1,425
Supply to Marketers - unaffiliated	4,633	1,725
Other (including natural gas gathering and processing)	2,330	1,548
Total	$ 33,324	8,307

Eight Flags

Eight Flags provides electricity and steam generation services through its CHP plant located on Amelia Island, Florida. The construction of the CHP plant was completed in June 2016. The CHP plant, which consists of a natural-gas-fired turbine and associated electric generator, produces approximately 21 MW of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of residual steam. Eight Flags sells power generated from the CHP plant to FPU, pursuant to a 20-year power purchase agreement for distribution to its retail electric customers. Eight Flags also sells steam, pursuant to a separate 20-year contract, to the industrial customer that owns the property on which Eight Flags' CHP plant is located. During 2017, Eight Flags generated $15.0 million in operating revenues from the sale of electricity to FPU and $2.1 million from the sale of steam.

The CHP plant is powered by natural gas transported by FPU through its distribution system and by Peninsula Pipeline. For the year ended December 31, 2017, Eight Flags and other affiliates of Chesapeake Utilities generated $4.9 million in additional gross margin. This amount includes gross margin of $537,000 attributable to natural gas distribution and transportation services provided to the CHP plant by Chesapeake Utilities' regulated affiliates.

OTHER BUSINESSES AND ELIMINATIONS

Overview

Other businesses and eliminations consists primarily of other unregulated subsidiaries, including Skipjack and ESRE, that own real estate leased to affiliates, eliminations of inter-segment revenue and certain unallocated corporate costs which are not directly attributable to a specific business unit. Skipjack and ESRE own and lease office buildings in Delaware and Maryland to divisions and other subsidiaries of Chesapeake Utilities. See *Item 8, Financial Statements and Supplementary Data* (Note 5, *Segment Information,* in the consolidated financial statements) for more information.

ENVIRONMENTAL COMPLIANCE

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 the effect on the environment of the disposal or release of specified substances at current and former operating sites. We have participated in the investigation, assessment or remediation, and have exposures at seven former MGP sites.

For additional information on each site, refer to *Item 8, Financial Statements and Supplementary Data* (see Note 19, *Environmental Commitments and Contingencies,* in the consolidated financial statements).

EMPLOYEES

As of December 31, 2017, we had a total of 945 employees, 118 of whom are union employees represented by two labor unions: the International Brotherhood of Electrical Workers 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	Position
Michael P. McMasters	59	President (March 2010 - present) Chief Executive Officer (January 2011 - present) Director (March 2010 - present) Executive Vice President (September 2008 - February 2010) Chief Operating Officer (September 2008 - December 2010) Chief Financial Officer (January 1997 - September 2008) *Mr. McMasters also previously served as Senior Vice President, Vice President, Treasurer, Director of Accounting and Rates and Controller.*
Beth W. Cooper	51	Senior Vice President (September 2008 - present) Chief Financial Officer (September 2008 - present) Assistant Secretary (March 2015-present) Corporate Secretary (June 2005 - March 2015) Vice President (June 2005 - September 2008) Treasurer (March 2003 - May 2012) *Ms. Cooper also previously served as Assistant Vice President, Assistant Treasurer, Director of Internal Audit and Director of Strategic Planning.*
Elaine B. Bittner	48	Senior Vice President of Strategic Development (May 2013 - present) Chief Operating Officer - Sharp, Aspire Energy and PESCO (May 2014 - Present) Vice President of Strategic Development (June 2010 - May 2013) Vice President, Eastern Shore (May 2005 - June 2010) *Ms. Bittner also previously served as Director of Eastern Shore, Director of Customer Services and Regulatory Affairs for Eastern Shore and Director of Environmental Affairs and Environmental Engineer.*
Stephen C. Thompson	57	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) *Mr. Thompson also previously served as Director of Gas Supply and Marketing for Eastern Shore, Superintendent of Eastern Shore and Regional Manager for Florida distribution operations.*
Jeffry M. Householder	60	President of Florida Public Utilities Company (June 2010 - present) *Prior to joining Chesapeake Utilities, Mr. Householder operated a consulting practice that provided business development and regulatory services to utilities, propane retailers and industrial clients.*
James F. Moriarty	60	Senior Vice President (February 2017 - present) General Counsel & Corporate Secretary (March 2015 - present) Vice President (March 2015 - February 2017) *Prior to joining Chesapeake Utilities, Mr. Moriarty was a Partner at Locke Lord LLP and Fulbright & Jaworski, LLP, both international law firms with offices in Washington, D.C.*

Available Information and 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 the SEC website *http://www.sec.gov* and 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.

CERTIFICATION TO THE NYSE

Our Chief Executive Officer certified to the NYSE on June 1, 2017 that, as of that date, he was unaware of any violation by Chesapeake Utilities of the NYSE's corporate governance listing standards.

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 our ability to access 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, both organically and through acquisitions. To the extent that we do not generate sufficient cash flow from operations, we may incur additional indebtedness to finance our growth. We rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements beyond the cash flows generated from our operations.

In addition, our ability to obtain adequate and cost-effective capital depends on our credit ratings, which are greatly affected by our financial performance and the liquidity of financial markets. A downgrade in our current credit ratings could adversely affect our access to capital markets, as well as our cost of capital. 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.

Our natural gas marketing subsidiary is exposed to market risks beyond our control, which could adversely affect our financial results and capital requirements.

Our natural gas marketing subsidiary 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.

Our natural gas marketing subsidiary is exposed to the credit risk of its counterparties.

Our natural gas marketing subsidiary extends credit to counterparties and continually monitors and manages collections aggressively. There is risk that our subsidiary may not be able to collect amounts owed to it. If the counter-party 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.

Our natural gas marketing subsidiary is dependent upon the availability of credit to successfully operate its business.

Our natural gas marketing subsidiary is dependent upon the availability of credit to buy natural gas for resale or to trade. If financial market conditions decline generally, or the financial condition of this subsidiary or of our Company declines, then the cost of credit could increase. If credit is not available, or if credit is more costly, our results of operations, cash flows and financial condition may be adversely affected.

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

To compensate for fluctuations in propane gas prices, we adjust our propane selling prices to the extent allowed by the market. There can be no assurance, however, that we will be able to increase propane sales prices sufficiently to compensate fully for such fluctuations in the cost of propane gas to us. If we are unable to increase propane sales prices sufficiently to compensate fully for such fluctuations, our earnings could be negatively affected, which would adversely impact our results of operations.

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, 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, a downgrade in our credit rating or the inability to borrow under certain credit agreements. Any such acceleration could cause a material adverse change in our financial condition.

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

An increase in interest rates, without the recovery of the higher cost of debt in the sales and/or transportation rates we charge our utility customers, could adversely affect future earnings. An increase 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 in the future to meet minimum federal government requirements as well as higher pension expense to be recorded in future years. Adverse changes in the asset values and 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.

Changes in tax laws or regulations, including the recently adopted TCJA, may negatively affect our results of operations, net income, financial condition and cash flows.

We are subject to taxation by various taxing authorities at the federal, state and local levels. On December 22, 2017, President Trump signed into law the TCJA, which significantly changes how the U.S. taxes corporations. The TCJA requires complex computations to be performed that were not previously required in U.S. tax law, significant judgments to be made in interpretation of the provisions of the TCJA, significant estimates in calculations, and the preparation and analysis of information not previously relevant or regularly produced. The U.S. Treasury Department, the IRS, and other standard-setting bodies could issue guidance on how provisions of the TCJA will be applied or otherwise administered that may differ from our interpretations. As we complete our analysis of the TCJA, collect and prepare necessary data, and interpret any additional guidance, we may make adjustments to provisional amounts that we have recorded that may materially impact our provision for income taxes in the period in which adjustments are made.

In addition, beginning in 2018, we expect to incur lower income tax expense, which will generally decrease our regulated energy businesses' projected effective income tax rates. Over time, the TCJA will likely result in lower regulated rates due to lower income tax expense recoveries and the potential refund of deferred income tax regulatory liabilities. We have used our best judgment in attempting to quantify and reserve for these estimated obligations generated by the TCJA. However, a challenge by a taxing authority, our ability to utilize these tax benefits in a different fashion, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates (see Note 11, *Income Taxes*, in the consolidated financial statements).

The TCJA is generally expected to result in lower operating cash flows from our regulated energy businesses as a result of the elimination of bonus depreciation and lower customer rates. As a result, we may need to access additional debt and equity capital to meet our financing needs, which we assume will be available.

Our stock price is subject to volatility.

The utility industry and the stock market as a whole have experienced more significant stock price and volume fluctuations that have affected stock prices in ways that may have been unrelated to operating performance. Our stock has experienced increased price and volume volatility as well. However, despite this increased volatility, we believe that our stock price should reflect expectations of future growth and profitability. We also believe our stock price should reflect expectations that our cash dividend will continue at current levels or grow, although future dividends are subject to declaration by our Board of Directors. We cannot predict the level of volatility in our stock price or volumes traded, which may fluctuate based upon our actual performance, including growth, profitability, and dividends paid, as well as for reasons unrelated to our operating performance or not under our control.

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) 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 could impact 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 transmission and/or distribution 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. 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. While there is active wholesale power sales competition in Florida, our retail electric business through FPU has remained substantially free from direct competition from other electric service providers. Generally, however, our retail electric business through FPU remains subject to 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 competition, could adversely affect our results of operations, cash flows and financial condition.

Propane. Our propane distribution 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 distribution 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 distribution 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 distribution and natural gas supply, gathering and processing operations, are sensitive to fluctuations in weather conditions, which directly influence the volume of natural gas and propane we sell and deliver to our customers. A significant portion of our natural gas and propane distribution revenue is derived from the sales and deliveries to residential and commercial heating customers during the five-month peak heating season (November through March). 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. A significant portion of our Ohio natural gas supply, gathering and processing services revenue is also generated during the five-month peak heating season (November through March) as a result of the natural gas requirements of its key customers, including Columbia Gas of Ohio, various regional marketers, and the CGC.

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.

Accidents, 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 customers through the regulatory process, our authorized rate of return, 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, results of operations 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 is dependent upon our continuing ability to attract, develop and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our aging 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. If a strike, work stoppage or other labor dispute were to occur, 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 limited 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. Our natural gas and electric distribution operations are currently in negotiations for franchises with certain municipalities for new service areas and renewal of some existing franchises. Ongoing financial results would be adversely impacted from the loss of service to certain operating areas within our electric or natural gas territories 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 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.

We have seen various legislative and regulatory initiatives to promote energy efficiency and conservation at both the federal and state levels. In response to the initiatives in the states in which we operate, we have implemented programs to promote energy efficiency by our current and potential customers. To the extent a PSC allows us to recover the cost of such energy efficiency programs, funding for such programs is recovered through the rates we charge to our regulated customers. However, lower energy consumption as a result of energy efficiency and conservation by current and potential customers may adversely affect our results of operations, cash flows and financial condition.

Commodity price increases may adversely affect the operating costs and competitive positions of our natural gas, electric and propane distribution 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 coal, 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, coal 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 volatile 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 two external suppliers. Any continued interruption of service from these suppliers could adversely affect our ability to meet the demands of FPU's customers, which could negatively impact our earnings, financial condition and results of operations.

The amount and availability of natural gas, propane and electricity supplies are difficult to predict; a substantial reduction in available supplies could reduce our earnings in those segments.

Natural gas, propane and electricity production can be affected by factors beyond our control, which may affect our ability to obtain sufficient supplies to meet demand and may adversely impact the financial results in those businesses. Any disruption in the availability of supplies of natural gas, propane and electricity could result in increased supply costs and higher prices for customers, which could also adversely affect our financial condition and results of operations.

We rely on a limited number of natural gas, propane and electricity suppliers and producers, the loss of which could have a material adverse effect on our financial condition and results of operations.

We have entered into various agreements with suppliers and producers to purchase natural gas, propane and electricity to serve our customers. The loss of any significant suppliers and/or producers or our inability to renew these contracts at favorable terms upon their expiration could significantly affect our ability to serve our customers and have a material adverse impact on our 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 distribution and natural gas marketing operations 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.

Our natural gas marketing subsidiary's earnings and operating cash flows are dependent upon optimization of physical assets.

Our natural gas marketing subsidiary'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 this subsidiary's market areas, including as a result of increased production along the Marcellus Shale, can reduce the subsidiary's 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. Our subsidiary 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 our subsidiary is not able to recoup these costs from customers, the cash flows and earnings of our subsidiary, and ultimately, the Company, could be adversely impacted.

Our propane inventory is subject to inventory valuation risk, which may result in a write-down of inventory.

Our propane distribution operations own or lease bulk propane storage facilities, with an aggregate capacity of approximately 6.8 million gallons. We purchase and store propane based on several factors, including inventory levels and the price outlook. We may purchase large volumes of propane at current market prices during periods of low demand and low prices, which generally occur during the summer months. Propane is a commodity, and as such, its price is subject to volatile fluctuations in response to changes in supply or other market conditions. We have no control over these market conditions. Consequently, the wholesale purchase price can change rapidly over a short period of time. The retail market price for propane could fall below the price at which we made the purchases, which would adversely affect our profits or cause sales from that inventory to be unprofitable. In addition, falling propane prices may result in inventory write-downs, as required by GAAP, if the market price of propane falls below our weighted average cost of inventory, which could adversely affect net income.

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 PSC, or the FERC in the case of Eastern Shore, 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.

Derivatives legislation and the implementation of related rules could have an adverse impact on our ability to hedge risks associated with our business.

The Dodd-Frank Act regulates derivative transactions, which include certain instruments used in our risk management activities. The Dodd-Frank Act contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility, subject to certain exceptions for entities that use swaps to hedge or mitigate commercial risk. Although the Dodd-Frank Act includes significant new provisions regarding the regulation of derivatives, the impact of those requirements will not be known definitively until regulations have been adopted and fully implemented by both the SEC and the Commodities Futures Trading Commission, and market participants establish registered clearing facilities under those regulations. Although we may qualify for exceptions, our derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the Dodd-Frank Act, which may increase our transaction costs, make it more difficult for us to enter into hedging transactions on favorable terms or affect the number and/or creditworthiness of available counterparties. Our inability to enter into hedging transactions on favorable terms, or at all, could increase operating expenses and increase exposure to risks of adverse changes in commodity prices, which could adversely affect the predictability of cash flows.

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 adoption of this type of legislation by Congress, or similar legislation by states, or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas and propane or impact the prices we charge to our customers. The direction of future U.S. climate change regulation is difficult to predict given the current uncertainties surrounding the policies of the Trump Administration. 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. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted 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.

There is a growing belief that emissions of greenhouse gases may be linked to global climate change. Climate 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. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues and cash flows. Extreme weather conditions in general require more system backups, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territories could also have an impact on our revenues and cash flows by affecting natural gas prices. Severe weather impacts our operating territories primarily through thunderstorms, tornadoes, hurricanes, and snow or ice storms. 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.

<u>*Key Properties*</u>

We own approximately 1,517 miles of natural gas distribution mains (together with related service lines, meters and regulators) located in Kent, New Castle and Sussex Counties, Delaware; and Caroline, Cecil, Dorchester, Wicomico and Worcester Counties, Maryland. We own approximately 2,906 miles of natural gas distribution mains (and related equipment) in Broward, Citrus, DeSoto, Gadsden, Gilchrist, Hillsborough, Holmes, Jackson, Liberty, Marion, Martin, Nassau, Osceola, Palm Beach, Pasco, 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 facilities in Delaware and Maryland, which we use for propane-air injection during periods of peak demand.

Through Eastern Shore, we own and operate approximately 457 miles of natural gas transmission pipeline, extending from supply 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. Through Peninsula Pipeline, we own and operate approximately 44 miles of natural gas transmission pipeline in Indian River, Palm Beach, Polk and Suwannee 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.

Through FPU, we own and operate approximately 20 miles of electric transmission line located in Nassau County, Florida and approximately 896 miles of electric distribution line in Calhoun, Jackson, Liberty and Nassau Counties, Florida.

We own approximately 338 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 bulk propane storage facilities, with an aggregate capacity of approximately 5.6 million gallons, in Delaware, Maryland, Pennsylvania and Virginia. In Florida, we own bulk propane storage facilities with an aggregate capacity of approximately 1.2 million gallons. These facilities are located on real estate that is either owned or leased by us.

Through Aspire Energy, we own 16 natural gas gathering systems and approximately 2,600 miles of pipeline in Central and Eastern Ohio.

We own or lease offices and other operational facilities in the following locations: Anne Arundel, Cecil, Dorchester, Somerset, Talbot, and 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, Ohio; and Pittsburgh, Pennsylvania.

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, Hendry, Jackson, Levy, Martin, Nassau, Okeechobee, Palm Beach and Volusia Counties, Florida. The FPU assets subject to the lien also include: 1,970 miles of natural gas distribution mains (and related equipment) in its service areas; 20 miles of electric transmission line located in Nassau County, Florida; 896 miles of electric distribution line located in Calhoun, Jackson, Liberty and Nassau Counties in Florida; propane storage facilities with a total capacity of 1.2 million gallons, located in south and central Florida; and 83 miles of underground propane distribution mains in Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Marion, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

ITEM 3. LEGAL PROCEEDINGS.

LEGAL PROCEEDINGS

As disclosed in *Item 8, Financial Statements and Supplementary Data* (see Note 20, *Other Commitments and Contingencies*, in the consolidated financial statements), we are involved in various legal actions and claims arising in the normal course of business. We are also involved in certain administrative proceedings before various governmental or regulatory agencies concerning rates. In the opinion of management, the ultimate disposition of these current proceedings will not have a material effect on our consolidated financial position, results of operations or cash flows.

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 PRICE RANGES, COMMON STOCK DIVIDENDS AND STOCKHOLDER INFORMATION:

At February 20, 2018, there were 2,321 holders of record of our common stock. The high, low and closing prices of our common stock and dividends declared per share for each calendar quarter during 2017 and 2016 are included in the below table.

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
2017					
	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**
2016					
	March 31	$ 67.36	$ 52.25	$ 62.97	$ 0.2875
	June 30	$ 66.19	$ 56.56	$ 66.18	$ 0.3050
	September 30	$ 67.88	$ 59.12	$ 61.06	$ 0.3050
	December 31	$ 70.00	$ 57.63	$ 66.95	$ 0.3050

We have paid a cash dividend to our common stock stockholders for 57 consecutive years. Dividends are payable at the discretion of our Board of Directors. Future payment of dividends, and the amount of these dividends, will depend on our financial condition, results of operations, capital requirements, and other factors. We declared quarterly cash dividends on our common stock in 2017 and 2016, totaling $1.2800 per share and $1.2025 per share, respectively.

Indentures to our long-term debt contain various restrictions which limit our ability to pay dividends. Refer to *Item 8, Financial Statements and Supplementary Data* (see Note 12, *Long-Term Debt*, in the consolidated financial statements) for additional information.

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 12, *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, 2017.

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, 2017 through October 31, 2017 [1]	373	$ 78.90	—	—
November 1, 2017 through November 30, 2017	—	—	—	—
December 1, 2017 through December 31, 2017	—	—	—	—
Total	373	$ 78.90	—	—

(1) In October 2017, 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 16, *Employee Benefit Plans*, in the consolidated financial statements). During the quarter, 373 shares were purchased through the reinvestment of dividends.

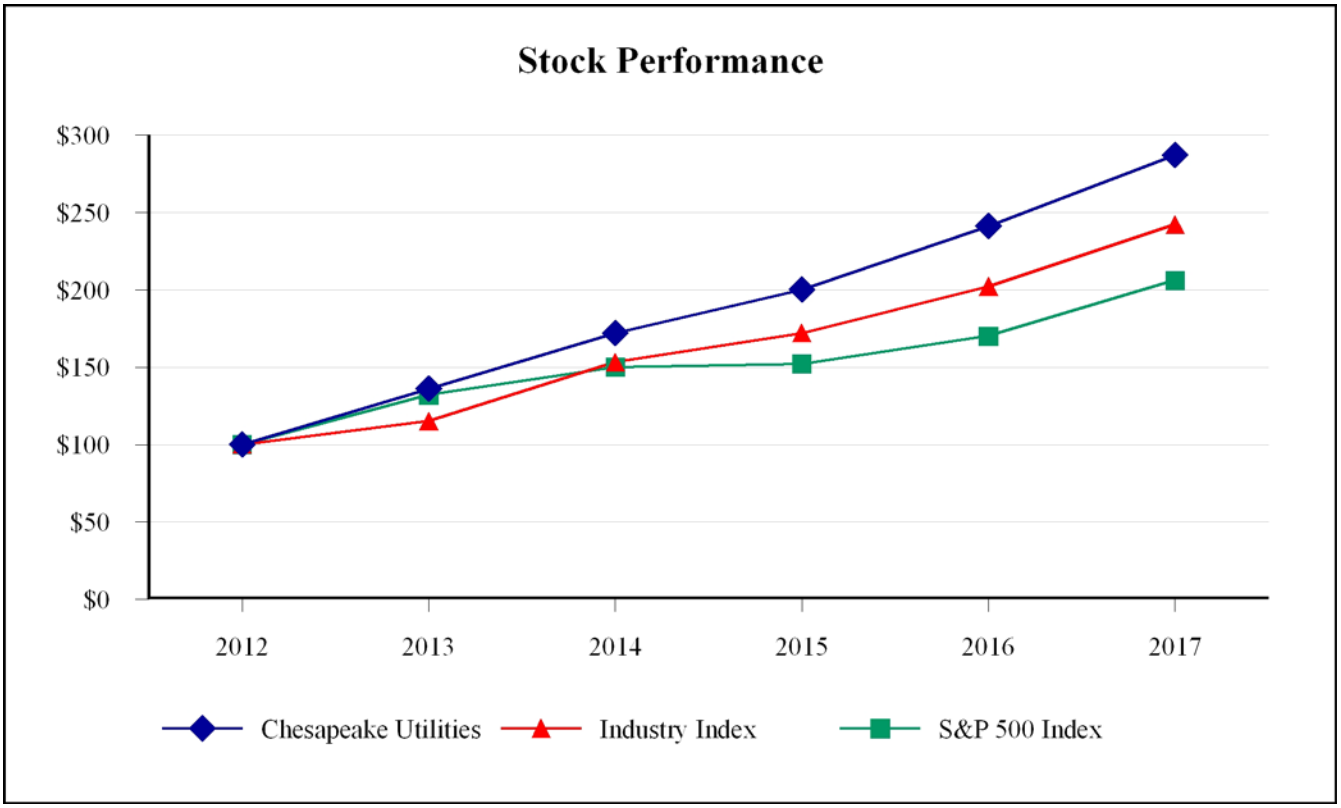
(2) Except for the purpose described in footnote [1], we have no publicly announced plans or programs to repurchase our shares.

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, 2017, with the cumulative total stockholder return of the S&P 500 Index and the cumulative total stockholder return of select peers, which include the following companies: Atmos Energy Corporation; Chesapeake Utilities Corporation; Black Hills Corporation; New Jersey Resources Corporation; NiSource, Inc.; Northwest Natural Gas Company; Northwestern Corporation; RGC Resources, Inc.; South Jersey Industries, Inc.; Spire, Inc.; Unitil Corporation; Vectren Corporation; and WGL Holdings, Inc.

The comparison assumes $100 was invested on December 31, 2012 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.



	2012	2013	2014	2015	2016	2017
Chesapeake Utilities	$ 100	$ 136	$ 172	$ 200	$ 241	$ 287
Industry Index	$ 100	$ 115	$ 153	$ 172	$ 202	$ 242
S&P 500 Index	$ 100	$ 132	$ 150	$ 152	$ 170	$ 206

ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,		
	2017	**2016**	**2015**
Operating			
(in thousands)			
Revenues			
Regulated Energy	**$ 326,310**	$ 305,689	$ 301,902
Unregulated Energy	**324,595**	203,778	162,108
Other businesses and eliminations	**(33,322)**	(10,607)	(4,766)
Total revenues	**$ 617,583**	$ 498,860	$ 459,244
Operating income			
Regulated Energy	**$ 73,160**	$ 69,851	$ 60,985
Unregulated Energy	**12,477**	13,844	16,355
Other businesses and eliminations	**206**	401	418
Total operating income	**$ 85,843**	$ 84,096	$ 77,758
Net income from continuing operations	**$ 58,124**	$ 44,675	$ 41,140
Assets			
(in thousands)			
Gross property, plant and equipment	**$ 1,312,117**	$ 1,175,595	$ 1,007,489
Net property, plant and equipment	**$ 1,126,027**	$ 986,664	$ 854,950
Total assets	**$ 1,417,434**	$ 1,229,219	$ 1,067,421
Capital expenditures	**$ 191,103**	$ 169,376	$ 195,261
Capitalization			
(in thousands)			
Stockholders' equity	**$ 486,294**	$ 446,086	$ 358,138
Long-term debt, net of current maturities	**197,395**	136,954	149,006
Total capitalization	**$ 683,689**	$ 583,040	$ 507,144
Current portion of long-term debt	**9,421**	12,099	9,151
Short-term debt	**250,969**	209,871	173,397
Total capitalization and short-term financing	**$ 944,079**	$ 805,010	$ 689,692

(1) These amounts include the financial position and results of operation of FPU for the period from the merger closing (October 28, 2009) to December 31, 2009. These amounts also include the effects of acquisition accounting and issuance of our common shares as a result of the merger.

For the Year Ended December 31,						
2014	2013	2012	2011	2010	2009[1]	2008
$ 300,442	$ 264,637	$ 246,208	$ 256,226	$ 269,438	$ 138,671	$ 116,123
184,961	166,723	133,049	149,586	146,793	119,973	161,290
13,431	12,946	13,245	12,215	11,315	10,141	14,030
$ 498,834	$ 444,306	$ 392,502	$ 418,027	$ 427,546	$ 268,785	$ 291,443
$ 50,451	$ 50,084	$ 46,999	$ 43,911	$ 43,267	$ 26,668	$ 23,833
11,723	12,353	8,355	9,619	8,150	8,390	3,600
105	297	1,281	175	513	(1,322)	1,046
$ 62,279	$ 62,734	$ 56,635	$ 53,705	$ 51,930	$ 33,736	$ 28,479
$ 36,092	$ 32,787	$ 28,863	$ 27,622	$ 26,056	$ 15,897	$ 13,607
$ 870,125	$ 805,394	$ 697,159	$ 625,488	$ 584,385	$ 543,905	$ 381,689
$ 689,762	$ 631,246	$ 541,781	$ 487,704	$ 462,757	$ 436,587	$ 280,671
$ 904,469	$ 837,522	$ 733,746	$ 709,066	$ 670,993	$ 615,811	$ 385,795
$ 98,057	$ 108,039	$ 78,210	$ 44,431	$ 46,955	$ 26,294	$ 30,844
$ 300,322	$ 278,773	$ 256,598	$ 240,780	$ 226,239	$ 209,781	$ 123,073
158,486	117,592	101,907	110,285	89,642	98,814	86,422
$ 458,808	$ 396,365	$ 358,505	$ 351,065	$ 315,881	$ 308,595	$ 209,495
9,109	11,353	8,196	8,196	9,216	35,299	6,656
88,231	105,666	61,199	34,707	63,958	30,023	33,000
$ 556,148	$ 513,384	$ 427,900	$ 393,968	$ 389,055	$ 373,917	$ 249,151

	For the Year Ended December 31,		
	2017	**2016**	**2015**
Common Stock Data and Ratios			
Basic earnings per share from continuing operations	**$ 3.56**	$ 2.87	$ 2.73
Diluted earnings per share from continuing operations	**$ 3.55**	$ 2.86	$ 2.72
Diluted earnings per share growth - 1 year	**24.1%**	5.1%	10.1%
Diluted earnings per share growth - 5 year	**12.3%**	8.4%	8.4%
Diluted earnings per share growth - 10 year	**10.7%**	9.3%	8.4%
Return on average equity from continuing operations	**12.6%**	11.3%	12.1%
Common equity / total capitalization	**71.1%**	76.5%	70.6%
Common equity / total capitalization and short-term financing	**51.5%**	55.4%	51.9%
Capital expenditures / average total capitalization	**30.2%**	31.1%	29.5%
Book value per share (2)	**$ 29.75**	$ 27.36	$ 23.45
Market price:			
High	**$ 86.35**	$ 70.00	$ 61.13
Low	**$ 63.00**	$ 52.25	$ 44.37
Close	**$ 78.55**	$ 66.95	$ 56.75
Weighted average number of shares outstanding (2)	**16,336,789**	15,570,539	15,094,423
Shares outstanding at year-end (2)	**16,344,442**	16,303,499	15,270,659
Registered common shareholders	**2,334**	2,373	2,396
Cash dividends declared per share (2)	**$ 1.28**	$ 1.20	$ 1.13
Dividend yield (annualized) (3)	**1.7%**	1.8%	2.0%
Book yield	**4.5%**	4.7%	5.1%
Payout ratio from continuing operations (4)	**36.0%**	41.8%	41.5%
Additional Data			
Customers			
Natural gas distribution	**153,537**	149,179	144,872
Electric distribution	**32,026**	31,695	31,430
Propane distribution	**54,760**	54,947	53,682
Total employees	**945**	903	832

(1) These amounts include the financial position and results of operation of FPU for the period from the merger closing (October 28, 2009) to December 31, 2009.

(2) 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.

(3) 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.

(4) The payout ratio from continuing operations is calculated by dividing cash dividends declared per share (for the year) by basic earnings per share from continuing operations.

For the Year Ended December 31,

2014(2)	2013(2)	2012(2)	2011(2)	2010(2)	2009(1)(2)	2008(2)
$ 2.48	$ 2.27	$ 2.01	$ 1.93	$ 1.83	$ 1.45	$ 1.33
$ 2.47	$ 2.26	$ 1.99	$ 1.91	$ 1.82	$ 1.43	$ 1.32
9.3%	13.6%	4.2%	4.9%	27.3%	8.3%	2.3%
11.6%	11.4%	9.1%	10.3%	8.5%	5.6%	2.4%
8.5%	6.8%	8.1%	7.8%	6.7%	3.0%	6.7%
12.2%	12.2%	11.6%	11.6%	11.6%	11.2%	11.2%
65.5%	70.3%	71.6%	68.6%	71.6%	68.0%	58.7%
54.0%	54.3%	60.0%	61.1%	58.2%	56.1%	49.4%
22.9%	28.6%	22.0%	13.3%	15.0%	10.2%	15.7%
$ 20.59	$ 19.28	$ 17.82	$ 16.78	$ 15.84	$ 14.89	$ 12.02
$ 52.660	$ 40.780	$ 32.613	$ 29.687	$ 28.133	$ 23.333	$ 23.227
$ 37.493	$ 30.560	$ 26.593	$ 24.000	$ 18.673	$ 14.680	$ 14.620
$ 49.660	$ 40.013	$ 30.267	$ 28.900	$ 27.680	$ 21.367	$ 20.987
14,551,308	14,430,962	14,379,216	14,333,699	14,211,831	10,969,980	10,217,772
14,588,711	14,457,345	14,396,248	14,350,959	14,286,293	14,091,471	10,240,682
2,329	2,345	2,396	2,481	2,482	2,670	1,914
$ 1.07	$ 1.01	$ 0.96	$ 0.91	$ 0.87	$ 0.83	$ 0.81
2.2%	2.6%	3.2%	3.2%	3.2%	3.9%	3.9%
5.4%	5.4%	5.5%	5.6%	5.7%	6.2%	6.8%
43.0%	44.6%	47.8%	47.4%	47.6%	57.6%	60.5%
141,227	138,210	124,015	121,934	120,230	117,887	65,201
31,272	31,151	31,066	30,986	30,966	31,030	—
53,272	51,988	49,312	48,824	48,100	48,680	34,981
753	842	738	711	734	757	448

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.

Unless otherwise noted, earnings per share information is presented on a diluted basis.

INTRODUCTION

We are a diversified energy company engaged, directly or through our various operating divisions and subsidiaries, in regulated and unregulated energy businesses.

Our strategy is focused on growing earnings from a stable utility foundation and investing in related businesses and services that provide opportunities for returns greater than traditional utility returns. We are focused on identifying and developing opportunities across the energy value chain, with emphasis on midstream and downstream investments that are accretive to earnings per share and consistent with our long-term growth strategy.

The key elements of this strategy include:

- executing a capital investment program in pursuit of growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding our energy distribution and transmission businesses organically 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 unregulated energy markets and business lines that will complement our existing operating units and growth strategy while capitalizing on opportunities across the energy value chain; and
- differentiating the Company as a full-service energy supplier/partner/provider through a customer-centric model.

Given our strong utility foundation and the growth that Eastern Shore and Peninsula Pipeline have cultivated for the Company, we will continue to seek out opportunities like Aspire Energy, building on our existing midstream capabilities and pursuing additional midstream assets. In this regard, we will seek to leverage our pipeline capabilities, skill sets and assets and be a preferred owner and operator of pipeline systems to serve high growth markets within and beyond our existing footprint.

OVERVIEW AND HIGHLIGHTS

(in thousands except per share data) **For the Year Ended December 31,**	**2017**	**2016**	**Increase (decrease)**	**2016**	**2015**	**Increase (decrease)**
Operating Income:						
Regulated Energy	**$ 73,160**	$ 69,851	$ 3,309	$ 69,851	$ 60,985	$ 8,866
Unregulated Energy	**12,477**	13,844	(1,367)	13,844	16,355	(2,511)
Other businesses and eliminations	**206**	401	(195)	401	418	(17)
Total Operating Income	**85,843**	84,096	1,747	84,096	77,758	6,338
Other income (expense)	**(765)**	(441)	(324)	(441)	293	(734)
Interest charges	**12,645**	10,639	2,006	10,639	10,006	633
Income Before Income Taxes	**72,433**	73,016	(583)	73,016	68,045	4,971
Income taxes	**14,309**	28,341	(14,032)	28,341	26,905	1,436
Net Income	**$ 58,124**	$ 44,675	$ 13,449	$ 44,675	$ 41,140	$ 3,535
Earnings Per Share of Common Stock:						
Basic	**$ 3.56**	$ 2.87	$ 0.69	$ 2.87	$ 2.73	$ 0.14
Diluted	**$ 3.55**	$ 2.86	$ 0.69	$ 2.86	$ 2.72	$ 0.14

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:			
Federal tax reform impact	—	14,299	0.87
PESCO - unrealized MTM loss	(5,783)	(3,499)	(0.21)
Impact of winding down of Xeron operations and absence of 2016 loss	745	451	0.03
Weather impact	578	350	0.02
	(4,460)	11,601	0.71
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
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
Sandpiper SIR	291	176	0.01
	23,032	13,934	0.88
(Increased) Decreased Other Operating Expenses:			
Higher payroll expense	(6,487)	(3,925)	(0.25)
Higher 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)
Higher benefit and other employee-related expenses	(1,485)	(899)	(0.06)
Higher regulatory expenses associated with rate filings	(1,005)	(608)	(0.04)
Higher taxes other than property and income	(739)	(447)	(0.03)
Lower credit, collections & customer service expenses	515	311	0.02
Lower outside services and facilities maintenance costs	417	252	0.02
Higher vehicle expenses	(372)	(225)	(0.01)
Higher 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.**

2016 compared to 2015

Our net income increased by approximately $3.5 million or $0.14 per share (diluted) in 2016, compared to 2015. Key variances included:

(in thousands, except per share data)	**Pre-tax Income**	**Net Income**	**Earnings Per Share**
Year ended December 31, 2015 Reported Results	$ 68,045	$ 41,140	$ 2.72
Adjusting for unusual items:			
Weather impact, primarily in the first quarter	(3,595)	(2,200)	(0.15)
Net gain from settlement agreement associated with customer billing system	(1,370)	(838)	(0.06)
	(4,965)	(3,038)	(0.21)
Increased (Decreased) Gross Margins:			
Service expansions*	7,192	4,400	0.30
Eight Flags' CHP*	4,998	3,058	0.21
GRIP*	4,044	2,474	0.17
Natural gas growth (excluding service expansions)	2,734	1,673	0.11
Lower retail propane margins	(2,770)	(1,695)	(0.11)
Higher customer consumption - other	1,899	1,162	0.08
Implementation of Delaware Division new rates*	1,487	910	0.06
PESCO	1,043	638	0.04
Xeron trading losses	(847)	(518)	(0.04)
Sandpiper margins associated with conversions	736	450	0.03
Sharp energy-related services	(512)	(313)	(0.02)
	20,004	12,239	0.83
Increased Other Operating Expenses:			
Higher staffing and associated costs	(4,443)	(2,718)	(0.18)
Higher depreciation, asset removal and property tax costs due to new capital investments	(2,952)	(1,806)	(0.12)
Higher Eight Flags' operating expenses	(2,432)	(1,488)	(0.10)
Higher outside service and facility maintenance costs	(974)	(596)	(0.04)
	(10,801)	(6,608)	(0.44)
Net contribution from Aspire Energy	3,130	1,915	0.09
Increase in outstanding shares from September 2016 public offering	—	—	(0.05)
Interest charges	(633)	(387)	(0.03)
Change in other income (expense)	(734)	(449)	(0.03)
Change in effective tax rate	—	530	0.04
Net other changes	(1,030)	(667)	(0.06)
Year ended December 31, 2016 Reported Results	$ 73,016	$ 44,675	$ 2.86

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

Summary of Key Factors

Major Projects and Initiatives

The following table summarizes gross margin for our major projects and initiatives recently completed and initiatives currently underway, but which will be completed in the future. Gross margin reflects operating revenue less cost of sales, excluding depreciation, amortization and accretion (dollars in thousands):

	Gross Margin for the Period							
	Year Ended December 31,			Year Ended December 31,			Estimate for	
	2017	2016	Variance	2016	2015	Variance	2018	2019
Existing Major Projects and Initiatives								
Capital Investment Projects	**$ 38,251**	$ 29,819	$ 8,432	$ 29,819	$ 14,304	$ 15,515	$ 34,041	$ 34,137
Eastern Shore Rate Case [1]	**3,693**	—	3,693	—	—	—	9,800	9,800
Settled Delaware Division Rate Case	**2,318**	1,487	831	1,487	—	1,487	2,250	2,250
Electric Limited Proceeding	**94**	—	94	—	—	—	1,558	1,558
Total Existing Major Projects and Initiatives	**$ 44,356**	$ 31,306	$ 13,050	$ 31,306	$ 14,304	$ 17,002	$ 47,649	$ 47,745
Future Major Projects and Initiatives								
Capital Investment Projects								
2017 Eastern Shore System Expansion	**$ 433**	$ —	$ 433	$ —	$ —	$ —	$ 9,708	$ 15,799
Northwest Florida Expansion	**—**	—	—	—	—	—	3,484	6,032
Other Florida Pipeline Expansions	**—**	—	—	—	—	—	635	1,131
Total Future Major Projects and Initiatives	**$ 433**	$ —	$ 433	$ —	$ —	$ —	$ 13,827	$ 22,962
Total	**$ 44,789**	$ 31,306	$ 13,483	$ 31,306	$ 14,304	$ 17,002	$ 61,476	$ 70,707

[1]Eastern Shore filed an uncontested settlement agreement with the FERC in December 2017. FERC approved the settlement agreement by a letter order on February 28, 2018. The order will be deemed final upon the expiration of the right to rehearing on March 30, 2018.

Major Projects and Initiatives Recently Completed

The following table summarizes gross margin generated by our major projects and initiatives recently completed (dollars in thousands):

	Gross Margin for the Period					
	Year Ended December 31,			Year Ended December 31,		
	2017	2016	Variance	2016	2015	Variance
Capital Investment Projects:						
Service Expansions:						
Short-term contracts (Delaware)	**$ 6,522**	$ 11,454	$ (4,932)	$ 11,454	$ 4,952	$ 6,502
Long-term contracts (Delaware)	**8,141**	1,815	6,326	1,815	1,844	(29)
Long-term contracts (Florida)	**235**	—	235	—	—	—
Total Service Expansions	**$ 14,898**	$ 13,269	$ 1,629	$ 13,269	$ 6,796	$ 6,473
Florida GRIP	**$ 13,454**	$ 11,552	$ 1,902	$ 11,552	$ 7,508	$ 4,044
Eight Flags' CHP Plant	**$ 9,899**	$ 4,998	$ 4,901	$ 4,998	$ —	$ 4,998
Total Capital Investment Projects	**$ 38,251**	$ 29,819	$ 8,432	$ 29,819	$ 14,304	$ 15,515

Service Expansions

White Oak Mainline Expansion Project
In August 2014, Eastern Shore entered into a precedent agreement with an electric power generator in Kent County, Delaware, to provide a 20-year natural gas transmission for 45,000 Dts/d. In July 2016, the FERC authorized Eastern Shore to construct and operate the project, which consists of 5.4 miles of 16-inch pipeline looping and new compression capability in Delaware. Eastern Shore provided interim services to this customer until construction was completed and long-term service commenced in March 2017. This service generated an additional gross margin of $85,000 during the year ended December 31, 2017 compared to 2016. Service provided under the 20-year agreement generated gross margin of $7.5 million during 2017 and is expected to generate between $5.8 million and $7.8 million annually through the remaining term of the agreement.

TETLP upgrades
In March 2016, Eastern Shore completed improvements at its TETLP interconnect facilities to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. This increased capacity generated additional gross margin of $1.2 million in 2017 compared to 2016.

2016 Eastern Shore System Reliability Project
In the second quarter of 2017, Eastern Shore completed construction of approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware, and a new compressor at its existing compressor station in Sussex County, Delaware to further enhance the reliability of its system. The 2016 System Reliability Project was included in Eastern Shore's January 2017 base rate case filing, for which a settlement agreement was filed with the FERC in December 2017. A discussion of the settlement agreement can be found below under “Regulatory Proceedings.”

New Smyrna Beach, Florida Project
In the fourth quarter of 2017, Peninsula Pipeline started construction of a 14-mile transmission pipeline in Volusia County, Florida, that interconnects with FGT's pipeline. Peninsula Pipeline entered into a 20-year agreement with FPU, which will assist FPU in serving its current and planned customer growth. We recognized $235,000 of margin from this expansion during the year ended December 31, 2017, and we expect to recognize gross margin of approximately $1.4 million annually thereafter.

GRIP
GRIP is a natural gas pipe replacement program approved by the Florida PSC, designed to expedite the replacement of qualifying distribution mains and services (any material other than coated steel or plastic) to enhance the reliability and integrity of the Florida natural gas distribution systems. This program allows recovery, through regulated rates, of capital and other program-related costs, inclusive of a return on investment, associated with the replacement of the mains and services. Since the program's inception in August 2012, we have invested $113.6 million to replace 247 miles of qualifying distribution mains, including $10.8 million and $26.0 million during 2017 and 2016, respectively. GRIP generated additional gross margin of $1.9 million in 2017 compared to 2016.

Eight Flags' CHP Plant
The Eight Flags CHP plant consists of a natural-gas-fired turbine and electric and steam generator in Amelia Island, Florida, which produces approximately 21 MW of base load power and 75,000 pounds per hour of residual steam. In June 2016, Eight Flags began selling power generated from the plant to FPU under a 20-year power purchase agreement for distribution to its retail electric customers. In July 2016, Eight Flags began selling steam, under a separate 20-year contract, to the industrial customer that owns the property on which the plant is located.

The CHP plant is powered by natural gas transported by FPU, through its distribution system, and by Peninsula Pipeline. For the year ended December 31, 2017, Eight Flags and other affiliates of Chesapeake Utilities generated $4.9 million in additional gross margin as a result of these services. The increase for the year ended December 31, 2017, includes $537,000 in gross margin from FPU and Peninsula Pipeline.

Regulatory Proceedings

Eastern Shore Rate Case
In December 2017, Eastern Shore filed an uncontested settlement agreement for its January 2017 base rate case filing with the FERC. FERC approved the settlement agreement by a letter order on February 28, 2018. The order will be deemed final upon the expiration of the right to rehearing on March 30, 2018. Under the terms of the settlement agreement, Eastern Shore would recover the costs of its 2016 System Reliability Project, along with the cost of investments and expenses associated with various expansion, reliability and safety initiatives. Pursuant to the settlement agreement, Eastern Shore would record and recognize an increase in annual base rates of approximately $9.8 million, prior to any federal tax reform impact. However, the settlement agreement prescribes the methodology for adjusting these rates as a result of tax reform. For the twelve months ended December 31, 2017, Eastern Shore recognized incremental gross margin of approximately $3.7 million.

Delaware Division Rate Case
In December 2016, the Delaware PSC approved a settlement agreement, which, among other things, provided for an increase in our Delaware Division revenue requirement of approximately $2.3 million and a rate of return on common equity of 9.75 percent. The new authorized rates went into effect on January 1, 2017. For the year ended December 31, 2017, we recorded incremental gross margin of approximately $831,000 related to the rate case.

Electric Limited Proceeding
In July 2017, FPU filed a petition with the Florida PSC for the recovery of a limited number of investments and associated costs related to reliability, safety and modernization initiatives for its electric distribution systems, as well as the investment and costs associated with the previously filed FPL interconnect project. In December 2017, the Florida PSC approved FPU’s electric limited proceeding filing via a settlement agreement, including a $1.6 million annualized rate increase effective for meter reads beginning in early January 2018. This increase will continue through at least the last billing cycle of December 2019. For the year ended December 31, 2017, additional margin of $94,000 was generated. The settlement agreement prescribes the methodology for adjusting the new rates as a result of the recent tax reform.

Major Projects and Initiatives Currently Underway

2017 Expansion Project
This project will expand Eastern Shore's firm service capacity by 26 percent, providing 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system with an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities pursuant to precedent agreements entered into with existing customers. We expect to invest approximately $117.0 million in this expansion project, which will generate approximately $15.8 million of gross margin in the first full year after the new transportation services go into effect. In October 2017, the FERC issued a CP authorizing Eastern Shore to construct and operate the proposed 2017 Expansion Project. In December 2017, the TETLP interconnect was placed into service. In conjunction with this interconnect going into service, Eastern Shore recognized incremental gross margin of $433,000, including interim services, for the year ended December 31, 2017. The remaining segments of the 2017 Expansion Project are expected to be placed into service in various phases over the second through fourth quarters of 2018.

Northwest Florida Expansion Project
Peninsula Pipeline and our Florida natural gas division are constructing a pipeline in Escambia County, Florida, that will interconnect with the FGT interstate pipeline. The project consists of 33 miles of 12-inch transmission line from the FGT interconnect along with 4.7 miles of 10-inch transmission line that will be operated by Peninsula Pipeline and 4.8 miles of 8-inch lateral distribution lines that will be operated by our Florida natural gas division. We have signed agreements to serve two large customers and continue to market to other customers close to the facilities. The estimated annual gross margin from this project is $6.0 million, and the project is currently expected to be in service by the end of the second quarter of 2018. We are currently in negotiations with several customers to provide additional services that could, if finalized, necessitate a capacity increase in this expansion project and, therefore, generate additional gross margin.

(Palm Beach County) Belvedere, Florida Project
Peninsula Pipeline is constructing a pipeline in Palm Beach County, Florida, that will interconnect with FGT's pipeline. The project consists of approximately two miles of transmission pipe that will bring gas directly to FPU’s distribution system in West Palm Beach. Completion of this project is expected by the end of the third quarter of 2018. Estimated annual gross margin associated with the project is approximately $600,000.

Other Natural Gas Growth - Distribution Operations
Customer growth for the Delmarva Peninsula natural gas distribution operations generated $1.6 million in additional gross margin for the year ended December 31, 2017, compared to the same period in 2016. The average number of residential customers on the Delmarva Peninsula increased by 3.8 percent in 2017 compared to 2016.

Our Florida natural gas distribution operations generated $1.2 million in additional gross margin for the year ended December 31, 2017, compared to 2016, with approximately two-thirds of the margin growth generated from commercial and industrial customers and one-third of the margin growth generated from new residential customers.

Weather and Consumption
Although 2017 was warmer than the prior year, colder temperatures in the fourth quarter generated additional margin for the year of $578,000. Compared to normal, warmer-than-normal temperatures in 2017 reduced gross margin by $2.0 million. The following table summarizes HDD and CDD variances from the 10-year average HDD/CDD ("Normal") for 2017, 2016 and 2015.

HDD and CDD Information

For the Years Ended December 31,	2017	2016	Variance	2016	2015	Variance
Delmarva						
Actual HDD	**3,800**	3,979	(179)	3,979	4,363	(384)
10-Year Average HDD ("Normal")	**4,374**	4,453	(79)	4,453	4,496	(43)
Variance from Normal	**(574)**	(474)		(474)	(133)	
Florida						
Actual HDD	**533**	672	(139)	672	569	103
10-Year Average HDD ("Normal")	**818**	828	(10)	828	859	(31)
Variance from Normal	**(285)**	(156)		(156)	(290)	
Ohio						
Actual HDD	**5,126**	5,529	(403)	5,529	2,404	N/A [1]
10-Year Average HDD ("Normal")	**5,914**	5,918	(4)	5,918	2,903	N/A [1]
Variance from Normal	**(788)**	(389)		(389)	(499)	
Florida						
Actual CDD	**3,013**	3,152	(139)	3,152	3,338	(186)
10-Year Average CDD ("Normal")	**2,865**	2,820	45	2,820	2,760	60
Variance from Normal	**148**	332		332	578	

[1] HDD for Ohio is presented from April 1, 2015 through December 31, 2015 since Aspire Energy commenced operations on April 1, 2015.

Propane Results

Our Florida and Delmarva Peninsula propane distribution operations continue to pursue a multi-pronged growth strategy, 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 our propane vehicular platform through AutoGas fueling stations; and optimization of our supply portfolio to generate incremental margin opportunities. Over the years, we have focused on meeting customer energy demand, and we have created a portfolio of offerings regardless of whether the customer is served via a pipeline or through an individual tank. AutoGas is our most recent offering that meets customers' varying demands.

These operations generated $2.8 million in incremental margin for the year ended December 31, 2017, compared to 2016. In addition, successful marketing initiatives led to increased volumes sold and revenues from service contracts. Supply management initiatives, including favorable hedging of propane purchases, have facilitated improvement in retail propane margins as well as opportunities to generate incremental margin from wholesale sales.

The following tables summarize gross margin for our propane distribution operations for the year ended December 31, 2017:

	Gross Margin Increase	
For the Year Ended	**12/31/2017**	
Growth in wholesale propane margins and sales	$	678
Higher retail propane margins per gallon		645
Increased customer consumption driven by growth and other factors		657
Higher service contract revenue		248
Additional growth in AutoGas		171
Additional customer consumption - weather		122
Other		279
	$	2,800

PESCO

PESCO markets and sells natural gas to wholesale, industrial and commercial customers and manages natural gas storage and transportation assets in several market areas. PESCO also provides management of storage and transportation assets for natural gas producers and regulated utilities. These management transactions typically involve the release of storage and/or transportation capacity in combination with an obligation to purchase and/or deliver natural gas. In April 2017, PESCO entered into 3-year asset management agreements with our Delmarva Peninsula natural gas distribution operations whereby PESCO manages a portion of their natural gas transportation and storage capacity.

In conjunction with the active management of these contracts, PESCO generates financial margin by identifying market opportunities and simultaneously entering into natural gas purchase/sale, storage or transportation contracts and/or financial derivatives contracts. The financial derivatives contracts consist primarily of exchange-traded futures that are used to manage volatility in natural gas market prices. Volatility in PESCO's recorded gross margin and operating income can occur over periods of time due to changes in the value of financial derivatives contracts prior to the time of the settlement of the financial derivatives and the purchase or sale of the underlying physical commodity. Derivatives accounting has no impact on economic gains or losses of the purchase or sale contracts. PESCO's results may also fluctuate based on the actual demand of its customers relative to its initial estimates of their demand, and PESCO's ability to manage its supply portfolio, considering weather and other factors, including pipeline constraints.

In the fourth quarter of 2017, PESCO executed financial derivatives contracts to lock in margin associated with a specified quantity of natural gas to be delivered in the first quarter of 2018. As regional natural gas prices rose during the fourth quarter of 2017, the financial derivatives contracts were valued based on MTM accounting, and an unrealized loss was recorded. Upon their settlement during the first quarter of 2018, these derivatives contracts will be matched against the physical contracts with the margin realized at that time.

For the year ended December 31, 2017, PESCO's gross margin decreased by $2.4 million, which represents the impact of the $5.8 million unrealized MTM loss related to financial derivatives contracts that were valued at the end of the year, offset by $3.4 million from: (a) additional gross margin generated primarily from natural gas sales to end users within one Columbia Gas of Ohio customer pool under a supplier agreement, which expired on March 31, 2017; and (b) increased margin from commercial and industrial customers served in Florida.

PESCO utilizes hedge accounting to better match the hedged items and the related hedging instruments when appropriate and we utilize MTM accounting in those situations where hedge accounting is not appropriate. In 2018, we will be adopting ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, the updated hedge accounting standard, which we expect will reduce the MTM volatility in PESCO's results due to better alignment of risk management activities and financial reporting, risk component hedging and certain other simplifications of hedge accounting guidance. PESCO's results for the year ended December 31, 2017, adjusted for the unrealized MTM loss, were as follows:

For the Year ended December 31, 2017 *(in thousands)*	**Gross Margin**	**Operating Income**
As Reported	**$ 2,212**	**$ (3,147)**
Unrealized MTM loss	5,783	5,783
Adjusted totals excluding unrealized MTM loss	**$ 7,995**	**$ 2,636**

Xeron

As disclosed previously, Xeron's operations were wound down during the second quarter of 2017. Operating income for the quarter and year ended December 31, 2017, improved by $854,000 and $880,000, respectively, due to the absence of the trading losses experienced in 2016. As part of the wind-down, we incurred non-recurring employee severance costs and other costs associated with the termination of leased office space in Houston, Texas during 2017. These expenses were recorded in other (expense) income, net. We do not anticipate incurring any additional costs that will have a material impact associated with winding down Xeron's operations.

Positioning the Company for Future Growth

Resource Allocation

To support and continue our growth, we have expanded, and will continue to expand, our resources and capabilities. Eastern Shore continues to significantly expand its transmission system, and has therefore increased its staffing. Growth in non-regulated energy businesses, including Aspire Energy, PESCO and Eight Flags, requires additional staff as well as corporate resources to support the increased level of business operations. Finally, to allow us to continue to identify and move growth initiatives forward and to manage their integration into Chesapeake Utilities' growing portfolio, resources have been added in our corporate shared services departments. In the twelve months ended December 31, 2017, our staffing and associated costs increased by $8.0 million, or 10.4 percent, compared to the same period in 2016. We have requested recovery of most of Eastern Shore's increased staffing costs in its 2017 rate case filing, for which we have filed an uncontested settlement agreement with the FERC. We are prudently managing the pace and magnitude of the investments being made, while ensuring that we appropriately expand our human resources and systems capabilities to manage current growth and to identify and capitalize on future growth opportunities. In support of these goals, we continue to pursue investments that typically are earnings accretive within the first twelve months.

Financing the Growth

Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. This target capital structure ensures that we maintain a strong balance sheet to support continued growth. Over the last several years, we have deployed increased amounts of capital on new projects, many of which have longer construction periods. We seek to align the permanent financing of these capital projects with the in-service dates to the extent feasible.

Accordingly, we have utilized increasing amounts of short-term debt to fund these projects. In September 2016, shortly after the completion of Eight Flags' CHP plant and several other key growth projects, we completed a $59.8 million public offering of our common stock, which increased our outstanding common stock by 960,488 shares. The higher number of shares outstanding reduced earnings per share by approximately $0.16 per share for the twelve months ended December 31, 2017.

As several large projects were completed in 2017, we refinanced $70.0 million of short-term debt as 3.25 percent senior notes. The refinancing resulted in increased interest expense of $1.6 million or $0.06 per share; however, we locked in a very low interest rate for 15 years. We also recently executed the NYL Shelf Agreement, pursuant to which we will issue NYL Shelf Notes in two tranches in 2018 at an average interest rate of 3.53% for 20 years. We expect to take advantage of additional available permanent capital to optimize long-term interest costs, ensure adequate and competitive funding for new investments and maintain a solid balance sheet to support future capital deployment.

REGULATED ENERGY

For the Year Ended December 31,	2017	2016	Increase (decrease)	2016	2015	Increase (decrease)
(in thousands)						
Revenue	**$ 326,310**	$ 305,689	$ 20,621	$ 305,689	$ 301,902	$ 3,787
Cost of sales	**118,769**	109,609	9,160	109,609	122,814	(13,205)
Gross margin	**207,541**	196,080	11,461	196,080	179,088	16,992
Operations & maintenance	**92,355**	88,098	4,257	88,098	83,616	4,482
Gain from a settlement	**(130)**	(130)	—	(130)	(1,497)	1,367
Depreciation & amortization	**28,554**	25,677	2,877	25,677	24,195	1,482
Other taxes	**13,602**	12,584	1,018	12,584	11,789	795
Operating expenses	**134,381**	126,229	8,152	126,229	118,103	8,126
Operating Income	**$ 73,160**	$ 69,851	$ 3,309	$ 69,851	$ 60,985	$ 8,866

2017 compared to 2016

Operating income for the Regulated Energy segment for 2017 was $73.2 million, an increase of $3.3 million, or 4.7 percent, compared to 2016. The increased operating income was due to an increase in gross margin of $11.5 million, offset by higher operating expenses of $8.2 million.

Gross Margin

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

(in thousands)	
Gross margin for the twelve months ended December 31, 2016	$ 196,080
Factors contributing to the gross margin increase for the twelve months ended December 31, 2017:	
Implementation of Eastern Shore rates	3,693
Natural gas growth (excluding service expansions)	2,818
Service expansions	2,062
Additional margin from GRIP in Florida	1,902
Implementation of Delaware Division rates	831
Service to Eight Flags	537
Other	(382)
Gross margin for the twelve months ended December 31, 2017	**$ 207,541**

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.

Implementation of Eastern Shore Rates

Eastern Shore generated additional gross margin of $3.7 million from implementation of new base rates as a result of its rate case filing. See *Note 18, Rates and Other Regulatory Activities*, to the consolidated financial statements for additional details.

Natural Gas Growth (Excluding Service Expansions)

Increased gross margin of $2.8 million from growth (excluding service expansions) was generated primarily from:

- $1.6 million from a 3.8 percent increase in the average number of residential customers served by the Delmarva Peninsula 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 of the margin growth generated from new residential customers.

Service Expansions

We generated additional gross margin of $2.1 million from natural gas service expansions from the following:

- $1.2 million from natural gas service expansions related to short-term firm service that commenced in March 2016, following certain measurement and related improvements to Eastern Shore's interconnect with TETLP, which increased Eastern Shore's natural gas receipt capacity from TETLP;
- $433,000 from Eastern Shore's new interim services provided to industrial customers in Delaware as a result of a portion of Eastern Shore's 2017 Expansion Project being placed in service in December 2017;
- $298,000 from Eastern Shore's increase in rates for a long-term firm service to an industrial customer in New Castle County, Delaware; and
- $235,000 generated by Peninsula Pipeline from the New Smyrna Beach Expansion Project.

Additional Revenue from GRIP in Florida

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. See *Note 18, Rates and Other Regulatory Activities,* to the consolidated financial statements for additional details.

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 by our affiliates to Eight Flags' CHP plant.

Other Operating Expenses

Other operating expenses increased by $8.2 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; partially offset by
- $529,000 in lower credit, collection and customer services expenses.

2016 compared to 2015

Operating income for the Regulated Energy segment for 2016 was $69.9 million, an increase of $8.9 million, or 14.5 percent, compared to 2015. The increased operating income was due primarily to an increase in gross margin of $17.0 million partially offset by an $8.1 million increase in other operating expenses to support growth.

Gross Margin

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

(in thousands)		
Gross margin for the year ended December 31, 2015	$	179,088
Factors contributing to the gross margin increase for the year ended December 31, 2016:		
Service expansions		7,192
Additional revenue from GRIP in Florida		4,044
Natural gas growth (excluding service expansions)		2,734
Implementation of Delaware Division rates		1,487
Service to Eight Flags		1,369
Sandpiper SIR		736
Decreased customer consumption - weather		(282)
Other		(288)
Gross margin for the year ended December 31, 2016	$	196,080

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

Increased gross margin from natural gas service expansions was generated primarily from the following:

- $5.4 million associated with service to an electric power generator in Kent County, Delaware, representing $6.8 million from the short-term OPT Service that commenced in December 2015, which was offset by a $1.4 million decrease in gross margin from the conclusion of the interruptible service Eastern Shore provided to this customer in 2015;
- $1.4 million from short-term firm service that commenced in March 2016, following certain measurement and related improvements to Eastern Shore's interconnect with TETLP that increased Eastern Shore's natural gas receipt capacity from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d; and
- $719,000 from natural gas transmission service, which was part of the major expansion initiative in Polk County, Florida.
- The foregoing gross margin increases were offset by a gross margin decrease of $243,000 resulting from a reduction in Eastern Shore's rates for a long-term firm service to an industrial customer in New Castle County, Delaware.

Additional Revenue from GRIP in Florida

GRIP investments during 2016 and 2015 by our Florida natural gas distribution operations generated $4.0 million in additional gross margin.

Natural Gas Growth (excluding service expansions)

Increased gross margin from other growth in natural gas (excluding service expansions) was generated primarily from:

- $1.5 million from a 3.6 percent increase in the average number of residential customers served by the Delmarva Peninsula natural gas distribution operations, as well as growth in the number of commercial and industrial customers; and
- $1.2 million from Florida natural gas distribution operations' customer growth, due primarily to new services to commercial and industrial customers.

Implementation of Delaware Division Rates

Our Delaware Division generated additional gross margin of $1.5 million from the implementation of rates as a result of its base rate filing, for the year ended December 31, 2016. See Note 18, *Rates and Other Regulatory Activities*, to the consolidated financial statements for additional details.

Service to Eight Flags

We generated additional gross margin of $1.4 million from new natural gas transmission and distribution services provided to Eight Flags' CHP plant, commencing in June 2016.

Sandpiper SIR

Sandpiper generated additional gross margin of $736,000 from higher margins associated with the continued conversion of its distribution system from propane to natural gas.

Operating Expenses

Operating expenses increased by $8.1 million. The significant components of the increase in operating expenses included:

- $3.6 million in higher staffing and associated costs for additional personnel to support growth;
- $2.6 million in higher depreciation, asset removal and property tax costs associated with recent capital investments to support growth and system integrity; and
- $1.4 million due to the absence of a $1.5 million gain from a customer billing system settlement in 2015.

UNREGULATED ENERGY

For the Year Ended December 31,	2017	2016	Increase (decrease)	2016	2015	Increase (decrease)
(in thousands)						
Revenue	**$ 324,595**	$ 203,778	$ 120,817	$ 203,778	$ 162,108	$ 41,670
Cost of sales	**252,023**	138,816	113,207	138,816	101,791	37,025
Gross margin	**72,572**	64,962	7,610	64,962	60,317	4,645
Operations & maintenance	**48,730**	42,659	6,071	42,659	36,536	6,123
Depreciation & amortization	**7,954**	6,386	1,568	6,386	5,679	707
Other taxes	**3,411**	2,073	1,338	2,073	1,747	326
Operating expenses	**60,095**	51,118	8,977	51,118	43,962	7,156
Operating Income	**$ 12,477**	$ 13,844	$ (1,367)	$ 13,844	$ 16,355	$ (2,511)

2017 Compared to 2016

Operating income for the Unregulated Energy segment for 2017 was $12.5 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 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 $4.4 million, or 31.9 percent, respectively, during 2017 compared to 2016.

Gross Margin

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

(in thousands)	
Gross margin for the year ended December 31, 2016	$ 64,962
Factors contributing to the gross margin increase for the year ended December 31, 2017:	
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 agreements	1,125
Higher wholesale propane sales and margins	678
Wind-down of Xeron operations	658
Improved retail propane margins	645
Other	413
Gross margin for the year ended December 31, 2017	**$ 72,572**

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.

Eight Flags

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

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.

Customer Consumption - Weather and Other

Gross margin increased by $2.1 million due to higher sales of propane for our propane distributions operations, increased demand for propane in Florida due to weather conditions during the third quarter of 2017 and increased deliveries by Aspire Energy. On the Delmarva Peninsula and in Ohio, significantly colder temperatures in the latter half of December drove increased customer demand.

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 Delmarva Peninsula propane distribution operations, as well as higher throughput margins in Florida. Growth of the wholesale business is a component of our propane growth strategy.

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.

<u>Other Operating Expenses</u>

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.

2016 Compared to 2015

Operating income for the Unregulated Energy segment for 2016 was $13.8 million, a decrease of $2.5 million, compared to 2015. The decrease primarily reflected the impact of warmer weather, a return to more normal retail margins in the propane business and an operating loss generated by Xeron. Gross margin contributions in 2016 from Aspire Energy, Eight Flags and PESCO, offset most of the impact. The overall increase in gross margin of $4.6 million, was more than offset by an increase in other operating expenses of $7.2 million.

<u>Gross Margin</u>

Items contributing to the year-over-year gross margin increase were as follows:

(in thousands)	
Gross margin for the year ended December 31, 2015	$ 60,317
Factors contributing to the gross margin increase for the year ended December 31, 2016:	
Aspire Energy	5,947
Eight Flags' CHP plant	3,629
Decreased retail propane margins	(2,770)
Decreased customer consumption - weather and other	(1,414)
Natural gas marketing - PESCO	1,043
Lower margins for Xeron	(847)
Decreased wholesale propane margins	(279)
Other	(664)
Gross margin for the year ended December 31, 2016	$ 64,962

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.

Aspire Energy

Aspire Energy generated $5.9 million in additional gross margin in 2016, of which $4.2 million was realized in the first quarter of 2016, due to the fact that 2015 included only nine months of results. Aspire Energy became a wholly-owned subsidiary of Chesapeake Utilities on April 1, 2015. Pricing amendments to long-term gas sales agreements, additional management fees and higher volumes delivered to Columbia Gas of Ohio and CGC contributed $1.7 million of this increase.

Eight Flags' CHP Plant

Eight Flags' CHP plant, which commenced operations in June 2016, generated $3.6 million in gross margin from the sale of steam and electricity generated by the plant during 2016, compared to no margin in 2015.

Decreased Retail Propane Margins

Lower retail propane margins for our Delmarva Peninsula and Florida propane distribution operations decreased gross margin by $2.8 million in 2016, of which $2.4 million is associated with the larger Delmarva Peninsula propane distribution operation, as retail margins per gallon returned to more normal levels. The decline in margin was driven principally by lower propane prices and local market conditions. The levels of retail margins per gallon generated during 2015 were not expected to be sustained over the long term. Accordingly, we continue to assume more normal levels of margins in our long-term financial plans and forecasts.

Decreased Customer Consumption - Weather and Other

Gross margin decreased by $1.4 million as a result of lower sales due to warmer weather in 2016 compared to 2015. In addition, the lower sales were expected as more customers in Ocean City, Maryland, and surrounding areas were converted from propane to natural gas.

Natural Gas Marketing - PESCO

Gross margin generated by PESCO was $4.6 million in 2016, compared to $3.6 million in 2015. Favorable results in 2016 from increased customer contracts in Florida and on the Delmarva Peninsula were offset by a $1.5 million loss associated with the SCO supplier agreement, where revenue from transported volumes was insufficient to cover PESCO’s fixed storage and pipeline fees, given the seasonality of volumes as well as warmer temperatures. Under the contract, PESCO paid fixed storage and pipeline fees over the entire twelve-month period, although the volumes were highest in the first quarter of 2017, followed by the fourth quarter of 2016 (contract period of April 1, 2016 - March 31, 2017).

Lower Margins for Xeron

Gross margin generated by Xeron was ($546,000) in 2016 compared to $301,000 in 2015. Gross margin was impacted by unfavorable crude oil and propane futures trading.

<u>*Operating Expenses*</u>

Operating expenses increased by $7.2 million. The significant components of the increase in operating expenses included:

- $2.8 million in operating expenses incurred by Aspire Energy, with $1.6 million representing expenses incurred in the first quarter of 2016, compared to zero in the first quarter of 2015, when Aspire Energy’s operations had not yet commenced;
- $2.4 million incurred by Eight Flags' CHP plant, which commenced operations in June 2016;
- $817,000 in higher staffing and additional costs for additional personnel to support growth; and
- $683,000 in higher outside services costs associated primarily with growth and ongoing compliance activities.

OTHER INCOME (EXPENSE)

Other income (expense) for 2017, 2016, and 2015 was $(765,000), $(441,000) and $293,000, respectively, which includes costs incurred in winding down Xeron, non-operating investment income, interest income, late fees charged to customers and gains or losses from the sale of assets for our unregulated businesses.

INTEREST EXPENSE

2017 Compared to 2016

Interest charges for 2017 increased by approximately $2.0 million, or 18.9 percent, compared to 2016. The increase is attributable to an increase of $1.3 million in interest on higher short-term borrowings and an increase of $1.0 million in interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017. The remaining balance is interest expense related to customer deposits.

2016 Compared to 2015

Interest charges for 2016 increased by approximately $633,000, or 6.3 percent, compared to 2015. The increase is attributable to an increase of $1.3 million in interest expense from higher short-term borrowings, offset by a decrease of $469,000 in long-term interest charges due to principal repayments of our long-term debt. The remaining balance is interest expense related to customer deposits.

INCOME TAXES

2017 Compared to 2016

Income tax expense was $14.3 million for 2017, compared to $28.3 million in 2016. The decrease was due primarily to the revaluation of deferred tax assets and liabilities from our unregulated businesses as a result of the implementation of the TCJA, which decreased our deferred income tax expense by $14.3 million. Excluding the impact of the implementation of the TCJA, our effective tax rate was 39.5 percent in 2017, compared to 38.8 percent in 2016. Our expected effective tax rate for 2018 is approximately 27.5 percent.

2016 Compared to 2015

Income tax expense was $28.3 million for 2016, compared to $26.9 million in 2015. The increase was due primarily to higher taxable income. Our effective tax rate was 38.8 percent in 2016, compared to 39.5 percent in 2015.

LIQUIDITY AND CAPITAL RESOURCES

Our capital requirements reflect the capital-intensive and seasonal nature of our business and are principally attributable to investment in new plant and equipment, retirement of outstanding debt and seasonal variability in working capital. We rely on cash generated from operations, short-term borrowings, and other sources to meet normal working capital requirements and to temporarily finance capital expenditures. We may also issue long-term debt and equity to fund capital expenditures and to more closely align our capital structure to our target capital structure.

Our energy businesses are weather-sensitive and seasonal. We normally generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas, electricity, and propane delivered by our distribution operations and our natural gas 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.

Capital expenditures for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures were $191.1 million (including the purchase of certain assets of ARM) in 2017, $169.4 million in 2016 and $195.2 million ($142.7 million, excluding $52.5 million, net of cash received, in connection with our acquisition of Gatherco) in 2015. The most significant capital expenditures in 2017 included investments in Eastern Shore's expansion projects, which include the 2016 System Reliability Project, the White Oak Mainline project, and the 2017 System Expansion Project, as well as the Northwest Florida Expansion Project and GRIP.

We have budgeted $181.6 million for capital expenditures in 2018. The following table shows the 2018 capital expenditure budget by segment and by business line:

(dollars in thousands)		
Regulated Energy:		
Natural gas distribution	$	53,899
Natural gas transmission		92,562
Electric distribution		7,972
Total Regulated Energy		154,433
Unregulated Energy:		
Propane distribution		11,235
Other unregulated energy		5,827
Total Unregulated Energy		17,062
Other:		
Corporate and other businesses		10,097
Total Other		10,097
Total 2018 Capital Expenditures	$	181,592

The 2018 budget, excluding acquisitions, includes the remaining capital expenditures associated with Eastern Shore's 2017 System Expansion Project; Florida's Northwest Florida Expansion Project; additional expansions of our natural gas distribution and transmission systems; continued natural gas infrastructure improvement activities; expenditures for continued replacement under the Florida GRIP; 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 and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts. On average, over the last five years, our actual capital expenditures have averaged 91 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 to provide the financial flexibility needed to access capital markets when required. 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. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors.

The following presents our capitalization, excluding and including short-term borrowings, as of December 31, 2017 and 2016:

(in thousands)	**December 31, 2017**			December 31, 2016		
Long-term debt, net of current maturities	**$**	**197,395**	**29%**	$	136,954	23%
Stockholders' equity		**486,294**	**71%**		446,086	77%
Total capitalization, excluding short-term borrowings	**$**	**683,689**	**100%**	$	583,040	100%

(in thousands)	**December 31, 2017**			December 31, 2016		
Short-term debt	**$**	**250,969**	**26%**	$	209,871	26%
Long-term debt, including current maturities		**206,816**	**22%**		149,053	19%
Stockholders' equity		**486,294**	**52%**		446,086	55%
Total capitalization, including short-term borrowings	**$**	**944,079**	**100%**	$	805,010	100%

Included in the long-term debt balances at December 31, 2017, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($620,000 excluding current maturities and $2.1 million including current maturities). At the closing of the ESG acquisition in May 2013, Sandpiper entered into this agreement, which has a six-year term. The capacity portion of this agreement is accounted for as a capital lease.

As of December 31, 2017, we did not have any 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, 2017, $209.7 million of Chesapeake Utilities' cumulative consolidated net income and $104.9 million of FPU's cumulative 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. We have maintained a ratio of equity to total capitalization, including short-term borrowings, between 50 percent and 56 percent during the past three years. In September 2016, we completed a public offering of 960,488 shares of our common stock at a public offering 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, which were added to our general funds and used to repay a portion of our short-term debt under unsecured lines of credit. Our equity to total capitalization ratio, including short-term borrowings, was 52 percent as of December 31, 2017.

As described below under "Short-Term Borrowings," we entered into the Credit Agreement and the Revolver with the Lenders in October 2015, which increased our borrowing capacity by $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. In addition, the exact timing of any long-term debt or equity issuance(s) will be based on market conditions.

Shelf Agreements

In October 2015, we entered into the Prudential Shelf Agreement, under which we may request that Prudential purchase, through October 8, 2018, up to $150.0 million of Prudential Shelf Notes. The Prudential Shelf Notes have a fixed interest rate and a maturity date not to exceed 20 years from the date of issuance. Prudential is under no obligation to purchase any of the Prudential Shelf Notes. The interest rate and terms of payment of any series of the Prudential Shelf Notes will be determined at the time of purchase.

In May 2016, Prudential approved the purchase of $70.0 million of 3.25 percent Prudential Shelf Notes, which were issued on April 21, 2017. The proceeds received from this issuance were used to reduce short-term borrowings under the Revolver. The balance under the Revolver had accumulated over time as capital expenditures were temporarily financed. As of December 31, 2017, $80 million remains available for issuance under the Prudential Shelf Agreement.

In March 2017, we entered into the MetLife Shelf Agreement and the NYL Shelf Agreement, under which we may request that MetLife and NYL, through March 2, 2020, purchase up to $150.0 million and $100.0 million, respectively, of our unsecured senior debt. The unsecured senior debt would have a fixed interest rate and a maturity date not to exceed 20 years from the date of issuance. MetLife and NYL are under no obligation to purchase any unsecured senior debt. The interest rate and terms of payment of any series of unsecured senior debt will be determined at the time of purchase.

In November 2017, NYL agreed to purchase $50.0 million of 3.48% "Series A" notes and $50.0 million of 3.58% "Series B" notes. The Series A notes and Series B notes will be issued on or before May 21, 2018 and November 20, 2018, respectively. The proceeds received from these issuances will be used to reduce short-term borrowings under the Revolver, lines of credit and/or to fund capital expenditures. The NYL Shelf Agreement has been fully utilized.

As of December 31, 2017, no request has been made to MetLife to purchase unsecured senior debt under the MetLife Shelf Agreement.

The Prudential Shelf Agreement, the MetLife 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.

Short-Term Borrowings

Our outstanding short-term borrowings at December 31, 2017 and 2016 were $251.0 million and $209.9 million, respectively, at weighted average interest rates of 2.42 percent and 1.43 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 the capital expenditure program. In November 2017, we entered into a new $40.0 million credit facility with a new lender. As of December 31, 2017, we had five unsecured bank credit facilities with four financial institutions totaling $220.0 million in available credit. In addition, since October 2015, we have $150.0 million of additional short-term debt capacity available under the Revolver with five participating Lenders. The terms of the Revolver are described in further detail below. None of the unsecured bank lines of credit requires compensating balances. We are currently authorized by our Board of Directors to borrow up to $275.0 million of short-term borrowing. As of February 27, 2018 the Board increased this limit from $275.0 million to $350.0 million.

The $150.0 million Revolver has a five-year term 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% 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, 2017 and 2016 included $10.3 million and $8.6 million, respectively, of book overdrafts. Book overdrafts are not actual borrowings under the credit facilities; however, these book overdrafts, if presented, would be funded through the credit facilities and, therefore, were included in the short-term borrowings.

As of December 31, 2017, we had issued $5.0 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.

Our outstanding borrowings under these unsecured short-term credit facilities at December 31, 2017 and 2016 were $240.7 million and $201.3 million, respectively. Short-term borrowings were as follows during 2017, 2016 and 2015:

(in thousands)	**2017**	2016	2015
Average borrowings	**$ 183,561**	$ 172,808	$ 102,220
Weighted average interest rate	**2.03%**	1.43%	1.19%
Maximum month-end borrowings	**$ 240,671**	$ 201,311	$ 168,757

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the years ended December 31, 2017, 2016 and 2015:

	For the Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Net cash provided by (used in):			
Operating activities	**$ 110,089**	$ 104,141	$ 104,715
Investing activities	**(186,895)**	(170,037)	(164,539)
Financing activities	**78,242**	67,219	58,013
Net increase (decrease) in cash and cash equivalents	**1,436**	1,323	(1,811)
Cash and cash equivalents—beginning of period	**4,178**	2,855	4,574
Cash and cash equivalents—end of period	**$ 5,614**	$ 4,178	$ 2,763

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 working capital. Changes in working capital 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 by our natural gas and propane distribution 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 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 flows 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 currently 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.

During 2016 and 2015, net cash provided by operating activities was $104.1 million and $104.7 million, respectively, resulting in a decrease in cash flows of $574,000 in 2016. Significant operating activities generating the cash flow change were as follows:

- Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities decreased cash flows by $13.2 million, due primarily to higher revenues and the timing of the receipt of customer payments as well as increased expenses and the timing of payments to vendors.
- Net income, adjusted for non-cash adjustments and reconciling activities, increased cash flows by $18.3 million, due primarily to an increase in deferred income taxes as a result of the availability and utilization of bonus depreciation in 2016, which resulted in a higher book-to-tax timing difference and higher non-cash adjustments for depreciation and amortization.
- Changes in net regulatory assets and liabilities decreased cash flows by $11.4 million, due primarily to the change in fuel costs collected through the various fuel cost recovery mechanisms.
- The changes in income taxes increased cash flows by $7.4 million, due primarily to higher pre-tax income as a result of continued investment in the infrastructure, treatment, storage and distribution of natural gas, propane and electricity.
- Net cash flows from changes in propane, natural gas and materials inventories decreased net cash flows by approximately $4.1 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $186.9 million and $170.0 million during 2017 and 2016, respectively, resulting in a decrease in cash flows of $16.9 million in 2017. Significant investing activities generating the cash flows change were as follows:

- Cash paid for capital expenditures increased by $5.4 million to $175.3 million for 2017, compared to $169.9 million in 2016.
- 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.

Net cash used in investing activities totaled $170.0 million and $164.5 million for 2016 and 2015, respectively, resulting in a decrease in cash flows of $5.5 million in 2016. Significant investing activities contributing to the cash flow change were as follows:

- An increase in cash paid for capital expenditures year-over-year, due primarily to our GRIP investment in our Florida natural gas distribution operations, Eight Flags' construction of the CHP plant and Eastern Shore expansion projects, which collectively decreased cash flows by $26.3 million.
- In 2015, we paid $20.7 million in cash ($27.5 million paid, less $6.8 million of cash acquired) through our short-term borrowings in conjunction with the acquisition of Gatherco. In addition to the net cash consideration, we also issued 592,970 shares of our common stock, which had no cash flow impact.

Cash Flows Provided by Financing Activities

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:

- We received $69.8 million in net cash proceeds from the issuance of the Prudential Shelf Notes, 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 under our line of credit arrangements 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.
- We paid $19.9 million in cash dividends for 2017 compared to $17.5 million for 2016.

Net cash provided by financing activities totaled $67.2 million and $58.1 million for 2016 and 2015, respectively, resulting in an increase of $9.2 million in 2016. Significant financing activities generating the cash flow change were as follows:

- Net proceeds of $57.4 million, after deducting underwriting commissions and expenses, from the issuance of common stock during the third quarter of 2016, were used to pay down short-term debt under unsecured lines of credit.
- Net borrowings/repayments under the line of credit agreements decreased cash flows by $48.0 million largely due to the common stock issuance mentioned above.

CONTRACTUAL OBLIGATIONS

We have the following contractual obligations and other commercial commitments as of December 31, 2017:

	Payments Due by Period				
Contractual Obligations	**Less than 1 year**	**1 — 3 years**	**3 — 5 years**	**More than 5 years**	**Total**
(in thousands)					
Long-term debt (1)	$ 7,971	$ 26,226	$ 38,700	$ 132,300	$ 205,197
Operating leases (2)	2,665	2,733	1,469	3,702	10,569
Capital leases (2)	1,451	620	—	—	2,071
Purchase obligations (3)					
Transmission capacity	32,320	60,197	41,375	146,772	280,664
Storage capacity	1,336	1,567	567	71	3,541
Commodities	103,047	42,889	—	—	145,936
Electric supply	16,216	18,165	2,701	2,755	39,837
Unfunded benefits (4)	361	709	914	1,432	3,416
Funded benefits (5)	1,898	—	—	6,734	8,632
Total Contractual Obligations	**$ 167,265**	**$ 153,106**	**$ 85,726**	**$ 293,766**	**$ 699,863**

(1) This represents principal payments on long-term debt. See *Item 8, Financial Statements and Supplementary Data,* Note 12, *Long-Term Debt*, for additional information. The expected interest payments on long-term debt are $8.8 million, $16.0 million, $12.7 million and $18.5 million, respectively, for the periods indicated above. Expected interest payments for all periods total $56.1 million.

(2) See *Item 8, Financial Statements and Supplementary Data,* Note 14, *Lease Obligations*, for additional information.

(3) See *Item 8, Financial Statements and Supplementary Data,* Note 20, *Other Commitments and Contingencies*, for additional information.

(4) We have recorded long-term liabilities of $3.4 million at December 31, 2017 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 16, *Employee Benefit Plans*, for additional information on the plans.

(5) We have recorded long-term liabilities of $18.4 million at December 31, 2017 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 $1.9 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 16, *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, primarily PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. These subsidiaries have never defaulted on their obligations to pay their suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at December 31, 2017 was $72.0 million, with the guarantees expiring on various dates throughout 2018.

We have issued letters of credit totaling $5.0 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. These letters of credit have varying expiration dates extending through November 4, 2018. There were no draws on these letters of credit as of December 31, 2017. 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 20, *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 most 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 19, *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 the appropriate 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 7, *Derivative Instruments,* in the *C*onsolidated 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, 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 2017 indicated no impairment of goodwill. Additional information is presented in Item 8, *Financial Statements and Supplementary Data,* Note 10, *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 16, *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 2017, 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 $7,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $9,000.

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 $143,000 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. Our long-term debt at December 31, 2017 consists of fixed-rate Senior Notes and $8.0 million of fixed-rate secured debt. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowings based in part on the fluctuation in interest rates. Additional information about our long-term debt is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 12, *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 periodically adjust fuel rates to reflect changes in the wholesale cost of natural gas and electricity and to ensure that we 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

Sharp and Flo-gas 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 6.8 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate the risk of propane commodity price fluctuations on the inventory valuation, we have adopted a Risk Management Policy that allows our propane distribution 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 with which to contract in order to fulfill our natural gas purchase requirements.

PESCO is a party to natural gas swap and futures contracts. These contracts provide PESCO with 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 for 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, 2016 to December 31, 2017:

(in thousands)	**Balance at December 31, 2016**	**Increase (Decrease) in Fair Market Value**	**Less Amounts Settled**	**Balance at December 31, 2017**
PESCO	$ (677)	$ (5,470)	$ (6)	**$ (6,153)**
Sharp	710	(1,124)	1,606	**1,192**
Total	$ 33	$ (6,594)	$ 1,600	**$ (4,961)**

There were no changes in methods of valuations during the year ended December 31, 2017.

The following is a summary of fair market value of financial derivatives as of December 31, 2017, by method of valuation and by maturity for each fiscal year period.

(in thousands)	**2018**	**2019**	**2020**	**2021**	**Total Fair Value**
Price based on ICE - PESCO	$ (6,163)	$ (297)	$ 341	$ (34)	$ (6,153)
Price based on Mont Belvieu - Sharp	1,175	17	—	—	1,192
Total	$ (4,988)	$ (280)	$ 341	$ (34)	$ (4,961)

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 7, *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. While the impact of inflation has remained low in recent years, natural gas and propane prices are subject to rapid fluctuations. In the regulated natural gas and electric distribution operations, fluctuations in natural gas and electricity prices are passed on to customers through the fuel cost recovery mechanism in our tariffs. 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.

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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, 2017 and 2016, 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, 2017, 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, 2017, 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, 2017 and 2016, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2017, 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, 2017, 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 28, 2018

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Income

(in thousands, except shares and per share data)	For the Year Ended December 31, 2017	2016	2015
Operating Revenues			
Regulated Energy	**$ 326,310**	$ 305,689	$ 301,902
Unregulated Energy	**324,595**	203,778	162,108
Other businesses and eliminations	**(33,322)**	(10,607)	(4,766)
Total operating revenues	**617,583**	498,860	459,244
Operating Expenses			
Regulated Energy cost of sales	**118,769**	109,609	122,814
Unregulated Energy and other cost of sales	**219,145**	128,434	97,228
Operations	**127,571**	117,571	107,562
Maintenance	**12,701**	12,391	11,803
Gain from a settlement	**(130)**	(130)	(1,500)
Depreciation and amortization	**36,599**	32,159	29,972
Other taxes	**17,085**	14,730	13,607
Total operating expenses	**531,740**	414,764	381,486
Operating Income	**85,843**	84,096	77,758
Other (expense) income, net	**(765)**	(441)	293
Interest charges	**12,645**	10,639	10,006
Income Before Income Taxes	**72,433**	73,016	68,045
Income taxes	**14,309**	28,341	26,905
Net Income	**$ 58,124**	$ 44,675	$ 41,140
Weighted Average Common Shares Outstanding:			
Basic	**16,336,789**	15,570,539	15,094,423
Diluted	**16,383,352**	15,613,091	15,143,373
Earnings Per Share of Common Stock:			
Basic	**$ 3.56**	$ 2.87	$ 2.73
Diluted	**$ 3.55**	$ 2.86	$ 2.72
Cash Dividends Declared Per Share of Common Stock	**$ 1.2800**	$ 1.2025	$ 1.1325

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,		
(in thousands)	**2017**	**2016**	**2015**
Net Income	**$ 58,124**	$ 44,675	$ 41,140
Other Comprehensive Income (Loss), net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of $(31), $(29) and $(27), respectively	**(46)**	(48)	(40)
Net gain, net of tax of $432, $178, and $73, respectively	**663**	268	103
Cash Flow Hedges, net of tax:			
Unrealized (loss)/gain on commodity contract cash flow hedges, net of tax of $(8), $496 and $(150), respectively	**(11)**	742	(227)
Total Other Comprehensive Income (Loss)	**606**	962	(164)
Comprehensive Income	**$ 58,730**	$ 45,637	$ 40,976

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

Assets	**As of December 31, 2017**	**2016**
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	**$ 1,073,736**	$ 957,681
Unregulated Energy	**210,682**	196,800
Other businesses and eliminations	**27,699**	21,114
Total property, plant and equipment	**1,312,117**	1,175,595
Less: Accumulated depreciation and amortization	**(270,599)**	(245,207)
Plus: Construction work in progress	**84,509**	56,276
Net property, plant and equipment	**1,126,027**	986,664
Current Assets		
Cash and cash equivalents	**5,614**	4,178
Accounts receivable (less allowance for uncollectible accounts of $936 and $909, respectively)	**77,223**	62,803
Accrued revenue	**22,279**	16,986
Propane inventory, at average cost	**8,324**	6,457
Other inventory, at average cost	**12,022**	4,576
Regulatory assets	**10,930**	7,694
Storage gas prepayments	**5,250**	5,484
Income taxes receivable	**14,778**	22,888
Prepaid expenses	**13,621**	6,792
Derivative assets, at fair value	**1,286**	823
Other current assets	**7,260**	2,470
Total current assets	**178,587**	141,151
Deferred Charges and Other Assets		
Goodwill	**22,104**	15,070
Other intangible assets, net	**4,686**	1,843
Investments, at fair value	**6,756**	4,902
Regulatory assets	**75,575**	76,803
Receivables and other deferred charges	**3,699**	2,786
Total deferred charges and other assets	**112,820**	101,404
Total Assets	**$ 1,417,434**	$ 1,229,219

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

Capitalization and Liabilities	**As of December 31, 2017**	**2016**
(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 $0.4867 per share (authorized 50,000,000 shares)	**7,955**	7,935
Additional paid-in capital	**253,470**	250,967
Retained earnings	**229,141**	192,062
Accumulated other comprehensive loss	**(4,272)**	(4,878)
Deferred compensation obligation	**3,395**	2,416
Treasury stock	**(3,395)**	(2,416)
Total stockholders’ equity	**486,294**	446,086
Long-term debt, net of current maturities	**197,395**	136,954
Total capitalization	**683,689**	583,040
Current Liabilities		
Current portion of long-term debt	**9,421**	12,099
Short-term borrowing	**250,969**	209,871
Accounts payable	**74,688**	56,935
Customer deposits and refunds	**34,751**	29,238
Accrued interest	**1,742**	1,312
Dividends payable	**5,312**	4,973
Accrued compensation	**13,112**	10,496
Regulatory liabilities	**6,485**	1,291
Derivative liabilities, at fair value	**6,247**	773
Other accrued liabilities	**10,273**	7,063
Total current liabilities	**413,000**	334,051
Deferred Credits and Other Liabilities		
Deferred income taxes	**135,850**	222,894
Regulatory liabilities	**140,978**	43,064
Environmental liabilities	**8,263**	8,592
Other pension and benefit costs	**29,699**	32,828
Deferred investment tax credits and other liabilities	**5,955**	4,750
Total deferred credits and other liabilities	**320,745**	312,128
Environmental and other commitments and contingencies (Note 19 and 20)		
Total Capitalization and Liabilities	**$ 1,417,434**	$ 1,229,219

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Cash Flows

(in thousands)	For the Year Ended December 31, 2017	2016	2015
Operating Activities			
Net Income	**$ 58,124**	$ 44,675	$ 41,140
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	**36,599**	32,159	29,972
Depreciation and accretion included in operations expenses	**8,122**	7,334	6,978
Deferred income taxes, net	**11,085**	31,257	20,520
Realized (gain) loss on sale of assets/investments	**3,179**	695	(340)
Unrealized (gain) loss on investments/commodity contracts	**(1,001)**	(385)	96
Employee benefits and compensation	**1,577**	1,887	1,235
Share-based compensation	**2,490**	2,367	1,937
Other, net	**(750)**	(79)	47
Changes in assets and liabilities:			
Accounts receivable and accrued revenue	**(19,506)**	(27,013)	17,097
Propane inventory, storage gas and other inventory	**(9,036)**	(2,531)	1,527
Regulatory assets/liabilities, net	**(2,855)**	(7,523)	3,883
Prepaid expenses and other current assets	**(7,001)**	(1,387)	(759)
Accounts payable and other accrued liabilities	**15,596**	19,599	(11,324)
Income taxes receivable (payable)	**8,110**	2,466	(4,967)
Customer deposits and refunds	**5,513**	2,065	1,976
Accrued compensation	**2,488**	358	(331)
Other assets and liabilities, net	**(2,645)**	(1,803)	(3,972)
Net cash provided by operating activities	**110,089**	104,141	104,715
Investing Activities			
Property, plant and equipment expenditures	**(175,329)**	(169,861)	(143,599)
Proceeds from sale of assets	**708**	174	164
Acquisitions, net of cash acquired	**(11,945)**	—	(20,930)
Environmental expenditures	**(329)**	(350)	(174)
Net cash used in investing activities	**(186,895)**	(170,037)	(164,539)
Financing Activities			
Common stock dividends	**(19,928)**	(17,482)	(15,924)
Issuance of stock for Dividend Reinvestment Plan	**89**	811	813
Proceeds from issuance of common stock, net of expenses	**(10)**	57,360	—
Tax withholding payments related to net settled stock compensation	**(692)**	(770)	(592)
Change in cash overdrafts due to outstanding checks	**1,738**	3,920	2,450
Net borrowing under line of credit agreements	**39,338**	32,526	82,178
Proceeds from issuance of long-term debt	**69,807**	—	—
Repayment of long-term debt and capital lease obligation	**(12,100)**	(9,146)	(10,820)
Net cash provided by financing activities	**78,242**	67,219	58,105
Net Increase (Decrease) in Cash and Cash Equivalents	**1,436**	1,323	(1,719)
Cash and Cash Equivalents — Beginning of Period	**4,178**	2,855	4,574
Cash and Cash Equivalents — End of Period	**$ 5,614**	$ 4,178	$ 2,855

Supplemental Cash Flow Disclosures (see Note 6)

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, 2014	**14,588,711**	**$ 7,100**	**$ 156,581**	**$ 142,317**	**$ (5,676)**	**$ 1,258**	**$ (1,258)**	**$ 300,322**
Net Income	—	—	—	41,140	—	—	—	**41,140**
Other comprehensive loss	—	—	—	—	(164)	—	—	**(164)**
Dividends declared ($1.1325 per share)	—	—	—	(17,222)	—	—	—	**(17,222)**
Retirement savings plan and dividend reinvestment plan	43,275	21	2,214	—	—	—	—	**2,235**
Common stock issued in acquisition	592,970	289	29,876	—	—	—	—	**30,165**
Share-based compensation and tax benefit [4] [5]	45,703	22	1,640	—	—	—	—	**1,662**
Treasury stock activities[2]	—	—	—	—	—	625	(625)	**—**
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 income	—	—	—	—	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 ($1.2800 per share)	—	—	—	(21,045)	—	—	—	**(21,045)**
Dividend reinvestment plan	10,771	5	730	—	—	—	—	**735**
Stock issuance [3]	—	—	(10)	—	—	—	—	**(10)**
Share-based compensation and tax benefit [4] [5]	30,172	15	1,783	—	—	—	—	**1,798**
Treasury stock activities[2]	—	—	—	—	—	979	(979)	**—**
Balance at December 31, 2017	**16,344,442**	**$ 7,955**	**$ 253,470**	**$ 229,141**	**$ (4,272)**	**$ 3,395**	**$ (3,395)**	**$ 486,294**

(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.

(2) Includes 90,961, 76,745 and 70,631 shares at December 31, 2017, 2016 and 2015, 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 2017, 2016 and 2015, we withheld 10,269, 12,031 and 12,620 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 distribution operations in Delaware, Maryland, the eastern shore of Virginia, southeastern Pennsylvania and Florida; (b) our natural gas marketing operation providing natural gas supplies directly to commercial and industrial customers in Florida, Delaware, Maryland, Ohio and other states; (c) our natural gas supply, gathering and processing operation in central and eastern Ohio; and (d) our CHP plant in Florida that generates electricity and steam.

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 cash flows for the years ended December 31, 2016 and 2015 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 with respect to, among other things, 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, 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, 2017 and 2016 is provided in the following table:

(in thousands)	As of December 31, 2017	As of December 31, 2016
Property, plant and equipment		
Regulated Energy		
Natural gas distribution – Delmarva Peninsula	**$ 234,654**	$ 220,083
Natural gas distribution – Florida	**354,495**	331,281
Natural gas transmission – Delmarva	**357,264**	285,746
Natural gas transmission – Florida	**27,096**	27,018
Electric distribution – Florida	**100,227**	93,553
Unregulated Energy		
Propane distribution – Delmarva Peninsula	**79,139**	73,686
Propane distribution – Florida	**29,038**	26,359
Other unregulated natural gas services – Ohio	**66,037**	61,383
CHP - Florida	**35,239**	35,237
Other unregulated energy	**1,229**	135
Other	**27,699**	21,114
Total property, plant and equipment	**1,312,117**	1,175,595
Less: Accumulated depreciation and amortization	**(270,599)**	(245,207)
Plus: Construction work in progress	**84,509**	56,276
Net property, plant and equipment	**$ 1,126,027**	$ 986,664

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. The amounts that are determined to be non-refundable reduce property, plant and equipment at the time of such determination. During the years ended December 31, 2017, 2016 and 2015, there were $2.1 million, $1.0 million and $1.7 million, respectively, of non-refundable contributions or advances that reduced property, plant and equipment.

Allowance for Funds Used During Construction

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 rate making purposes when the completed projects are placed in service. During the years ended December 31, 2017, 2016 and 2015, AFUDC, which was reflected as a reduction of interest charges, 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, 2017 and 2016, 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 $652,000 and $580,000 at December 31, 2017 and 2016, respectively.

Capital Lease Asset

Property, plant and equipment for our Delmarva Peninsula natural gas distribution operation included a capital lease asset of $2.0 million and $3.4 million, net of accumulated amortization, at December 31, 2017 and 2016, respectively, related to Sandpiper's capacity, supply and operating agreement. The original fair value of this asset was $7.1 million. See Note 20, *Other Commitments and Contingencies*, for additional information. At December 31, 2017 and 2016, accumulated amortization for this capital lease asset was $5.1 million and $3.7 million, respectively. For the years ended December 31, 2017, 2016 and 2015, we recorded $1.4 million, $1.4 million and $1.3 million, respectively, in amortization of this capital lease asset, which was included in our fuel cost recovery mechanisms.

Jointly-owned Pipeline

Property, plant and equipment for our Florida natural gas transmission operation also included $6.7 million of assets, at December 31, 2017 and 2016, which consists of the 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida, jointly owned by Peninsula Pipeline and Peoples Gas. The amount included in property, plant and equipment represents Peninsula Pipeline's 45-percent ownership of this pipeline. Each party was responsible for financing its portion of the jointly-owned pipeline. This 16-mile pipeline was placed in service in December 2012. Accumulated depreciation for this pipeline totaled $1.3 million and $1.0 million, at December 31, 2017 and 2016, 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 2015, we entered into a settlement agreement with a vendor related to the implementation of a customer billing system. Pursuant to the agreement, we received $1.5 million in cash, which is reflected as "Gain from a settlement" in the accompanying consolidated statements of income. In May 2016, we received an additional $650,000 in cash; however, 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, 2017, 2016 and 2015:

	2017	**2016**	**2015**
Natural gas distribution – Delmarva Peninsula	**2.5%**	2.5%	2.4%
Natural gas distribution – Florida	**2.9%**	2.9%	2.9%
Natural gas transmission – Delmarva Peninsula	**2.8%**	2.7%	2.7%
Natural gas transmission – Florida	**3.5%**	3.9%	4.0%
Electric distribution – Florida	**3.4%**	3.5%	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	5-33 years
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, 2017, 2016 and 2015, we reported $8.1 million, $7.3 million and $7.0 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 were to determine 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 negotiated 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 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 and natural gas marketing customers, whose billing cycles do not coincide with our accounting periods.

Our Ohio natural gas supply operation recognizes revenues based on actual volumes of natural gas shipped using contractual rates, which are 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.

The propane wholesale marketing operation records trading activity for open contracts on a net mark-to-market basis in our consolidated statements of income. For propane bulk delivery customers without meters, we record revenue in the period the products are delivered and/or services are rendered.

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

All of our natural gas and electric distribution operations, except for two utilities that do not sell natural gas to end-use customers as a result of deregulation, have fuel cost recovery mechanisms. These mechanisms provide a method of adjusting the 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. Chesapeake Utilities' Florida Division and FPU's Indiantown division provide unbundled delivery service to their customers, whereby the customers are permitted to purchase their gas requirements directly from competitive natural gas marketers.

We charge flexible rates to our natural gas distribution industrial interruptible customers to compete with prices of alternative fuels which these customers are able to use. Neither we nor our interruptible customers are contractually obligated to deliver or receive natural gas on a firm service basis.

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 cost of natural gas, electricity and propane commodities, pipeline capacity costs needed to transport and store natural gas, transmission costs for electricity, gathering and processing gas costs, transportation costs to transport propane purchases to our storage facilities, and steam and electricity generation costs. Depreciation expense is not included in our 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 cost of removal 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 distribution sales of natural gas, electricity and propane and transportation services to customers. An allowance for doubtful accounts is recorded against amounts due to reduce the receivables balance to the amount we reasonably expect to collect based upon our collections experiences and our assessment of 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 2017, 2016 or 2015.

Goodwill and Other Intangible Assets

Goodwill is not amortized but is tested for impairment at least annually. Goodwill of a reporting unit is tested for impairment between annual tests 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 2017, 2016 and 2015 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 primarily include 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 PSC, 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 expense 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 is based on the actuarial table that is most reflective of the expected mortality of the plan participants and reviewed periodically.

Actual changes in the fair value of plan assets and the differences between the actual and expected return on plan assets could have a material effect on the amount of pension and postretirement benefit costs that we ultimately recognize. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately $7,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $9,000. A 0.25 percent change in the rate of return could change our annual pension cost by approximately $143,000 and would not have an impact on the postretirement and supplemental executive retirement plans because these plans are not funded.

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

Prior to its wind down in the second quarter of 2017, Xeron engaged in trading activities using forward and futures contracts, which were accounted for using the MTM method of accounting. Under MTM accounting, our trading contracts were recorded at fair value as derivative assets and liabilities. The changes in fair value of the contracts were recognized as gains or losses in revenues in the consolidated statements of income in the period of change.

Our natural gas, electric and propane distribution 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.

Our propane distribution 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. In 2018, we will be adopting ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, the updated hedge accounting standard, which we expect will reduce the MTM volatility in PESCO’s results due to better alignment of risk management activities and financial reporting, risk component hedging and certain other simplifications of hedge accounting guidance.

FASB Statements

Recently Adopted Accounting Standards

Inventory (ASC 330) - In July 2015, the FASB issued ASU 2015-11, *Simplifying the Measurement of Inventory.* Under this guidance, inventories are required to be measured at the lower of cost or net realizable value. Net realizable value represents the estimated selling price less costs associated with completion, disposal and transportation. We adopted ASU 2015-11 on January 1, 2017, on a prospective basis. Adoption of this standard did not have a material impact on our financial position or results of operations.

Recent Accounting Standards Yet to be Adopted

Revenue from Contracts with Customers (ASC 606) - In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. This standard provides a single comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, as well as across industries and capital markets. The standard contains principles that entities will apply to determine the measurement of revenue and when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to 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. In March 2016, FASB issued ASU 2016-08, *Principal versus Agent Considerations (Reporting Revenue Gross versus Net),* to clarify the implementation guidance on principal versus agent considerations. For public entities, this standard is effective for interim and annual financial statements issued beginning January 1, 2018.

We have completed our evaluation of our revenue sources and the impact on our financial position, results of operations and cash flows. In tandem, we have developed and documented accounting policies and position papers, which are intended to meet the requirements of this new revenue recognition standard. We have also completed our plan to update our internal controls. Since the third quarter of 2017, we have provided additional training to our employees and have implemented system and process changes that are associated with the adoption of the standard. We will adopt the updated accounting guidance in the first quarter of 2018, using the modified retrospective transition method, which will result in a cumulative adjustment that will decrease retained earnings and receivables and other deferred charges by $1.5 million, related to one long-term firm transmission contract with an industrial customer for which the timing and recognition of revenue will be shifted to later years. Based on our assessment, we believe that the implementation of this new standard will not have a material impact on the amount and timing of revenue recognition, other than the one long-term contract for which we will delay the recognition of approximately $407,000 in revenue from 2018 to future years.

Leases (ASC 842) - In February 2016, the FASB issued ASU 2016-02, *Leases*, which provides updated guidance regarding accounting for leases. This update requires a lessee to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. ASU 2016-02 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted.

The FASB allows companies to elect several practical expedients, in order to simplify the transition to the new standard. The following three expedients must all be elected together:

- An entity need not reassess whether any expired or existing contracts are or contain leases.
- An entity need not reassess the lease classification for any expired or existing leases (that is, all existing leases that were classified as operating leases in accordance with Topic 840 will continue to be classified as operating leases, and all existing leases that were classified as capital leases in accordance with Topic 840 will continue to be classified as capital leases).
- An entity need not reassess initial direct costs for any existing leases.

Other practical expedients that can be elected individually are:

- An entity may elect to use hindsight in determining the lease term and in assessing impairment of the entity's right-of-use assets.
- An entity may elect to apply the provisions of the new lease guidance at the effective date, without adjusting the comparative periods presented.

We expect to use the practical expedients to assist in implementation of this standard. We have assessed all of our leases and have concluded that we may have some operating leases that qualify for the short-term lease exception. Upon adoption, we will record the right-of-use assets and the lease liabilities related to our operating leases with a lease term in excess of one year. We do not believe that this will have a material impact on our financial position, results of operations or cash flows.

In January 2018, the FASB issued ASU 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*, which provides a practical expedient to not evaluate, under Topic 842, existing or expired land easements that were not previously accounted for as leases. We plan to utilize the provided practical expedient for existing and expired land easements and will assess all new or modified land easements and right-of-way agreements, under the guidance of ASU 2016-02, following its adoption.

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. ASU 2016-15 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. We believe that the implementation of this new standard will not have a material impact on our consolidated statement of cash flows.

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 the implementation of this new standard will not have a material impact on our financial position or results of operations.

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 outside a subtotal of income from operations. The update allows for capitalization of the service cost component when applicable. ASU 2017-07 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. The presentation of the service cost and other components in this update are to be applied retrospectively, and the capitalization of the service cost is to be applied prospectively on or after the effective date. Aside from changes in presentation, we believe that the 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 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) changes as a result of a change in the terms or conditions of the award. The guidance is effective for our annual financial statements beginning January 1, 2018, although early adoption is permitted. The amendments included in this standard are to be applied prospectively. We believe that the implementation of this new standard will not have a material impact on our financial position or results of operations.

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. Among other changes to hedge designation, 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 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. For disclosures, ASU 2017-12 requires a tabular presentation of the income statement effect of fair value and cash flow hedges, and it eliminates the requirement to disclose the ineffective portion of the change in fair value of hedging instruments. ASU 2017-12 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. We are evaluating the effect of this standard on our future financial position and results of operations. In 2018, we will be adopting the updated hedge accounting standard, which we expect will reduce the MTM volatility in PESCO's results due to better alignment of risk management activities and financial reporting, risk component hedging and certain other simplifications of hedge accounting guidance.

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. ASU 2018-02 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. We are evaluating the effect of this standard on our future financial position and results of operations.

3. EARNINGS PER SHARE

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

(in thousands, except shares and per share data)	For the Year Ended December 31, 2017	2016	2015
Calculation of Basic Earnings Per Share:			
Net Income	**$ 58,124**	$ 44,675	$ 41,140
Weighted average shares outstanding	**16,336,789**	15,570,539	15,094,423
Basic Earnings Per Share	**$ 3.56**	$ 2.87	$ 2.73
Calculation of Diluted Earnings Per Share:			
Net Income	**$ 58,124**	$ 44,675	$ 41,140
Reconciliation of Denominator:			
Weighted average shares outstanding — Basic	**16,336,789**	15,570,539	15,094,423
Effect of dilutive securities — Share-based compensation	**46,563**	42,552	48,950
Adjusted denominator — Diluted	**16,383,352**	15,613,091	15,143,373
Diluted Earnings Per Share	**$ 3.55**	$ 2.86	$ 2.72

4. ACQUISITIONS

Acquisitions in 2017

ARM, Chipola and Central Gas Asset Acquisitions

In August 2017, PESCO acquired certain natural gas marketing assets of ARM. We have accounted for the purchase of these assets as a business combination and recorded goodwill of $6.8 million, which is included in Unregulated Energy segment. The acquired assets complement PESCO's current asset portfolio and expand our regional footprint and retail demand in a market where we have existing pipeline capacity and wholesale liquidity. In connection with the acquisition, we recorded a contingent liability of $2.5 million, which represents the expected future payment of additional consideration to ARM based on the achievement of certain performance targets. The payment, which is expected to be paid in 2019, is contingent upon the achievement of certain gross margin targets during the 2018 calendar year. The recorded liability is based upon our most recent gross margin projections for the acquired assets and is subject to change based on actual performance or changes in our gross margin projections.

In August 2017, Flo-gas acquired certain operating assets of Chipola, which provides propane distribution service to approximately 800 residential and commercial customers in Bay, Calhoun, Gadsden, Jackson, Liberty, and Washington Counties, Florida.

In December 2017, Flo-gas acquired certain operating assets of Central Gas, which provides propane distribution service to approximately 325 residential and commercial customers in Glades, Highlands, Martin, Okeechobee, and St. Lucie Counties, Florida.

The revenue and net income from these acquisitions that were included in our consolidated statement of income for the year ended December 31, 2017, were not material. The amounts recorded in conjunction with these acquisitions are preliminary and subject to adjustment based on additional valuations performed during the measurement period.

Acquisition in 2015

Gatherco Merger

On April 1, 2015, we completed the merger with Gatherco, in which Gatherco merged with and into Aspire Energy, our then newly formed, wholly-owned subsidiary.

At closing, we issued 592,970 shares of our common stock, valued at $30.2 million based on the closing price of our common stock as reported on the NYSE on April 1, 2015. In addition, we paid $27.5 million in cash and assumed $1.7 million of existing outstanding debt, which we paid off on the same date. We also acquired $6.8 million of cash on hand at closing.

(in thousands)	Net Purchase Price
Chesapeake Utilities common stock issued	$ 30,164
Cash	27,494
Acquired debt	1,696
Aggregate amount paid in the acquisition	59,354
Less: cash acquired	(6,806)
Net amount paid in the acquisition	$ 52,548

The merger agreement provided for additional contingent cash consideration to Gatherco's shareholders of up to $15.0 million based on a percentage of revenue generated from potential new gathering opportunities during the five-year period following the closing. As of December 31, 2017, there have been no related gathering opportunities developed; therefore, no contingent liability has been recorded. We are unable to estimate the range of future undiscounted contingent liability outcomes at this time. However, a liability for additional contingent cash consideration may be recorded prior to April 2020 as additional information becomes available.

We incurred $1.3 million in transaction costs associated with this merger, of which $514,000 and $786,000 were expensed during the years ended December 31, 2015 and 2014, respectively. Transaction costs were included in operations expense in the consolidated statements of income. The revenues and net income from this acquisition for the years ended December 31, 2017, 2016 and 2015, included in our consolidated statements of income, were $33.3 million and $8.9 million, respectively, for 2017, $26.6 million and $2.1 million, respectively, for 2016 and $16.7 million and $312,000, respectively, for 2015.

The purchase price allocation of the Gatherco acquisition is as follows:

(in thousands)	Purchase Price Allocation
Purchase price	$ 57,658
Property plant and equipment	53,203
Cash	6,806
Accounts receivable	3,629
Income taxes receivable	3,163
Other assets	425
Total assets acquired	67,226
Long-term debt	1,696
Deferred income taxes	13,409
Accounts payable	3,837
Other current liabilities	745
Total liabilities assumed	19,687
Net identifiable assets acquired	47,539
Goodwill	$ 10,119

The goodwill reflects the value paid primarily for opportunities for growth in a new and strategic geographic area. All of the goodwill from this acquisition was recorded in the Unregulated Energy segment and is not deductible for income tax purposes.

5. 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 comprise two reportable segments:

- *Regulated Energy*. Includes 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 propane distribution as well as natural gas marketing, gathering, processing, transportation and supply. These operations are unregulated as to their rates and services. Effective June 2016, this segment includes electricity and steam generation through Eight Flags' CHP plant. Through March 2017, this segment also included the operations of Xeron, our propane and crude oil trading subsidiary that began winding down operations at the end of 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.

(in thousands)	For the Year Ended December 31, 2017	2016	2015
Operating Revenues, Unaffiliated Customers			
Regulated Energy	**$ 316,971**	$ 302,402	$ 300,674
Unregulated Energy	**300,612**	196,458	158,570
Total operating revenues, unaffiliated customers	**$ 617,583**	$ 498,860	$ 459,244
Intersegment Revenues (1)			
Regulated Energy	**$ 9,339**	$ 3,287	$ 1,228
Unregulated Energy	**23,983**	7,321	3,537
Other businesses	**774**	880	880
Total intersegment revenues	**$ 34,096**	$ 11,488	$ 5,645
Operating Income			
Regulated Energy	**$ 73,160**	$ 69,851	$ 60,985
Unregulated Energy	**12,477**	13,844	16,355
Other businesses and eliminations	**206**	401	418
Operating Income	**85,843**	84,096	77,758
Other (expense) income	**(765)**	(441)	293
Interest charges	**12,645**	10,639	10,006
Income Before Income taxes	**72,433**	73,016	68,045
Income taxes	**14,309**	28,341	26,905
Net Income	**$ 58,124**	$ 44,675	$ 41,140
Depreciation and Amortization			
Regulated Energy	**$ 28,554**	$ 25,677	$ 24,195
Unregulated Energy	**7,954**	6,386	5,679
Other businesses and eliminations	**91**	96	98
Total depreciation and amortization	**$ 36,599**	$ 32,159	$ 29,972
Capital Expenditures			
Regulated Energy	**$ 159,011**	$ 139,994	$ 98,372
Unregulated Energy	**26,190**	23,984	90,895
Other businesses	**5,902**	5,398	5,994
Total capital expenditures	**$ 191,103**	$ 169,376	$ 195,261

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

	As of December 31, 2017	2016
Identifiable Assets		
Regulated Energy	**$ 1,121,673**	$ 986,752
Unregulated Energy	**261,541**	226,368
Other businesses	**34,220**	16,099
Total identifiable assets	**$ 1,417,434**	$ 1,229,219

Our operations are entirely domestic.

6. SUPPLEMENTAL CASH FLOW DISCLOSURES

Cash paid for interest and income taxes during the years ended December 31, 2017, 2016 and 2015 were as follows:

	For the Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Cash paid for interest	**$ 12,420**	$ 10,315	$ 9,497
Cash paid for income taxes, net of refunds	**$ (4,114)**	$ (5,308)	$ 11,076

Non-cash investing and financing activities during the years ended December 31, 2017, 2016, and 2015 were as follows:

	For the Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Capital property and equipment acquired on account, but not paid for as of December 31	**$ 15,457**	$ 9,791	$ 10,268
Common stock issued for the Retirement Savings Plan	**$ —**	$ 777	$ 690
Common stock issued under the SICP	**$ 1,127**	$ 1,027	$ 1,594
Capital lease obligation	**$ 2,070**	$ 3,471	$ 4,824
Common stock issued in acquisition	**$ —**	$ —	$ 30,164

7. DERIVATIVE INSTRUMENTS

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supply and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution 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 sales” and are accounted for on an accrual basis. Our propane distribution and 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, 2017, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2017

In 2017, Sharp entered into futures and swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 7.7 million gallons of propane expected to be purchased from October 2017 through March 2019, of which positions covering 4.9 million gallons of forecasted future purchases were outstanding as of December 31, 2017. Under the futures and swap agreements, Sharp will receive the difference between the index prices (Mont Belvieu prices in October 2017 through March 2019) and the swap prices of $0.59 per gallon, to the extent the index price exceeds the contracted price. If the index prices are lower than the swap prices, Sharp will pay the difference. Sharp received a total of approximately $440,000, which represented the difference between the index prices and the contracted prices during 2017. We designated and accounted for these agreements as cash flow hedges, and there is no ineffective portion of these hedges. In October 2017, we exited agreements associated with 1.5 million gallons expected to be purchased from November 2017 through February 2018 and reclassified $520,000 of unrealized gains from other comprehensive income to propane cost of sales. At December 31, 2017, the futures and swap agreements had a fair value asset of approximately $1.2 million and a fair value liability of $2,000. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss).

PESCO enters into natural gas futures contracts associated with the purchase and sale of natural gas to specific customers. These contracts are effective through October 2021, and we designate and account for them as cash flow hedges. There is no ineffective portion of these hedges. At December 31, 2017, PESCO had a total of 17.2 million Dts hedged under natural gas futures contracts, with an asset fair value of approximately $92,000. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss).

In August 2017, PESCO entered into natural gas swap agreements associated with financial contracts acquired in the ARM acquisition to mitigate the risk of fluctuations in wholesale natural gas prices associated with 591,000 Dts PESCO expects to purchase through January 2020. We accounted for these swap agreements as cash flow hedges, which have a fair value liability of approximately $469,000 as of December 31, 2017. The change in fair value of the natural gas swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss).

The impact of PESCO's financial instruments that were not designated as hedges in our consolidated financial statements as of December 31, 2017 was $5.8 million, which was recorded as an increase in gas costs during the year ended December 31, 2017 and is associated with 2.9 million Dts of natural gas.

Hedging Activities in 2016

In 2016, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 4.1 million gallons of propane expected to be purchased through September 2017. Under the swap agreements, Sharp would receive the difference between the index prices (Mont Belvieu prices in October 2016 through September 2017) and the swap prices of $0.5225 and $0.5650 per gallon, to the extent the index prices exceeded the swap prices. Sharp received a total of approximately $663,000, which represented the difference between the index prices and swap prices during the months of October 2016 through September 2017. We designated and accounted for these swap agreements as cash flow hedges.

In December 2016, Sharp paid a total of $33,000 to purchase a put option to protect against a decline in propane prices and related potential inventory losses associated with 630,000 gallons for its propane price cap program in the 2016-2017 heating season. The put option expired without being exercised because the propane prices did not fall below the strike price of $0.5650 per gallon in December 2016, January 2017, or February 2017. We accounted for the put option as a fair value hedge, and there was no ineffective portion of this hedge.

In January 2016, PESCO entered into a supplier agreement with Columbia Gas of Ohio to provide natural gas supply for one of its local distribution customer pools. PESCO also assumed the obligation to store natural gas inventory to satisfy its obligations under the supplier agreement, which terminated on March 31, 2017. In conjunction with the supplier agreement, PESCO entered into natural gas futures contracts during the second quarter of 2016 in order to protect its natural gas inventory against market price fluctuations. We previously accounted for these contracts as fair value hedges, with any ineffective portion being reported directly in earnings and offset by any associated gain (loss) on the inventory value being hedged. During the third quarter of 2016, we discontinued hedge accounting as the hedges were no longer highly effective. As of March 31, 2017, all of these contracts had expired. The impact of our natural gas futures commodity contracts previously designated as fair value hedges and the related hedged item on our consolidated income statement for the year ended December 31, 2016, is presented below:

(in thousands)	Year Ended December 31, 2016 [1]
Commodity contracts	$ (233)
Fair value adjustment for natural gas inventory designated as the hedged item	681
Total increase in purchased gas cost	$ 448
The increase in purchased gas cost is comprised of the following:	
Basis ineffectiveness	$ (83)
Timing ineffectiveness	531
Total ineffectiveness	$ 448

(1) There were no natural gas futures commodity contracts designated as fair value hedges in 2017.

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedging instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost. To the extent that our natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or net realizable value.

Hedging Activities in 2015

In March, May and June 2015, Sharp paid a total of $143,000 to purchase put options to protect against a decline in propane prices and related potential inventory losses associated with 2.5 million gallons for the propane price cap program in the 2015-2016 heating season. We exercised the put options as propane prices fell below the strike prices of $0.4950, $0.4888 and $0.4500 per gallon in December 2015 through February 2016 and $0.4200 per gallon in January through March 2016. We received approximately $239,000, which represented the difference between the market prices and the strike prices during those months. We accounted for the put options as fair value hedges.

In March, May and June 2015, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 2.5 million gallons expected to be purchased for the 2015-2016 heating season. Under these swap agreements, Sharp would have received the difference between the index prices (Mont Belvieu prices in December 2015 through March 2016) and the swap prices, which ranged from $0.5200 to $0.5950 per gallon, for each swap agreement, to the extent the index prices exceeded the swap prices. If the index prices were lower than the swap prices, Sharp would have paid the difference. These swap agreements essentially fixed the price of the 2.5 million gallons that we purchased during this period. We accounted for the swap agreements as cash flow hedges. Sharp paid approximately $484,000, which represented the difference between the index prices and swap prices during the months of December 2015 through March 2016.

Commodity Contracts for Trading Activities

Shortly after the first quarter of 2017, Xeron wound down its operations. Xeron was previously engaged in trading activities using forward and futures contracts for propane and crude oil. These contracts were considered derivatives and were accounted for using the mark-to-market method of accounting. As of December 31, 2017 and 2016, Xeron had no outstanding contracts that were accounted for as derivatives.

Balance sheet offsetting

PESCO has entered into master netting agreements with counterparties that enable it 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, 2017 and 2016:

	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**

	At December 31, 2016		
(in thousands)	Gross amounts	Amounts offset	Net amounts
Accounts receivable	$ 2,764	$ 1,431	$ 1,333
Accounts payable	$ 5,335	$ 1,431	$ 3,904

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, 2017 and 2016, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	**Balance Sheet Location**	**December 31, 2017**	**December 31, 2016**
Derivatives not designated as hedging instruments			
Propane swap agreements	Derivative assets, at fair value	**$ 13**	$ 8
Put options	Derivative assets, at fair value	**—**	9
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative assets, at fair value	**92**	113
Propane swap agreements	Derivative assets, at fair value	**1,181**	693
Total asset derivatives		**$ 1,286**	$ 823

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	December 31, 2017	December 31, 2016
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Derivative liabilities, at fair value	**$ 5,776**	$ 773
Derivatives designated as cash flow hedges			
Natural gas swap contracts	Derivative liabilities, at fair value	**469**	—
Propane swap agreements	Derivative liabilities, at fair value	**2**	—
Total liability derivatives		**$ 6,247**	$ 773

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

	Amount of Gain (Loss) on Derivatives:			
		For the Year Ended December 31,		
(in thousands)	Location of Gain (Loss) on Derivatives	2017	2016	2015
Derivatives not designated as hedging instruments				
Realized gain (loss) on forward contracts and options [(1)]	Revenue	**$ 112**	$ (546)	$ 426
Unrealized (loss) on forward contracts [(1)]	Revenue	**—**	—	(126)
Natural gas futures contracts	Cost of sales	**(3,633)**	(541)	—
Propane swap agreements	Cost of sales	**8**	7	18
Natural gas swap contracts	Cost of sales	**1**	—	—
Derivatives designated as fair value hedges				
Put/Call option	Cost of sales	**(9)**	49	528
Put/Call option [(2)]	Propane inventory	**—**	—	43
Natural gas futures contracts	Natural gas inventory	**—**	(233)	—
Derivatives designated as cash flow hedges				
Propane swap agreements	Cost of sales	**1,607**	(364)	(120)
Propane swap agreements	Other comprehensive income (loss)	**487**	1,016	(323)
Call options	Cost of sales	**—**	—	(81)
Natural gas futures contracts	Cost of sales	**(456)**	345	—
Natural gas swap contracts	Cost of sales	**(822)**	—	—
Natural gas futures contracts	Other comprehensive income (loss)	**(1,476)**	222	109
Natural gas swap contracts	Other comprehensive income (loss)	**986**	—	—
Total		**$ (3,195)**	$ (45)	$ 474

(1) All of the realized and unrealized gain (loss) on forward contracts represents the effect of trading activities on our consolidated statements of income.
(2) As a fair value hedge with no ineffective portion, the unrealized gains and losses associated with this call option are recorded in cost of sales, offset by the corresponding change in the value of propane inventory (hedged item), which is also recorded in cost of sales. The amounts in cost of sales offset to zero, and the unrealized gains and losses of this call option effectively changed the value of propane inventory on the consolidated balance sheets.

8. 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:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities;

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; and

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).

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, 2017 and 2016, respectively:

		Fair Value Measurements Using:		
As of December 31, 2017	**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	**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**	**$ —**

		Fair Value Measurements Using:		
As of December 31, 2016	**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	$ 21	$ 21	$ —	$ —
Investments—guaranteed income fund	561	—	—	561
Investments—mutual funds and other	4,320	4,320	—	—
Total investments	4,902	4,341	—	561
Derivative assets	823	—	823	—
Total assets	$ 5,725	$ 4,341	$ 823	$ 561
Liabilities:				
Derivative liabilities	$ 773	$ —	$ 773	$ —

The following valuation techniques were used to measure fair value assets on a recurring basis as of December 31, 2017 and 2016:

Level 1 Fair Value Measurements:

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 Fair Value Measurements:

Derivative assets and liabilities — The fair values of forward contracts are measured using market transactions in either the listed or OTC 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 OTC markets.

Level 3 Fair Value Measurements:

Investments - guaranteed income fund — The fair values of these investments are recorded at the contract value, which approximates their fair value.

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2017 and 2016:

	For the Year Ended December 31,	
(in thousands)	**2017**	**2016**
Beginning Balance	**$ 561**	$ 279
Purchases and adjustments	**79**	123
Transfers/disbursements	**(53)**	151
Investment income	**61**	8
Ending Balance	**$ 648**	$ 561

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

At December 31, 2017 and 2016, 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, 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, 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, 2016, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of $145.9 million compared to the estimated fair value of $161.5 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

See Note 16, *Employee Benefit Plans*, for fair value measurement information related to our pension plan assets.

9. INVESTMENTS

The investment balances at December 31, 2017 and 2016, consisted of the following:

	As of December 31,	
(in thousands)	**2017**	**2016**
Rabbi trust (associated with the Non-Qualified Deferred Compensation Plan)	**$ 6,734**	$ 4,881
Investments in equity securities	**22**	21
Total	**$ 6,756**	$ 4,902

We classify these investments as trading securities and report them at their fair value. For the years ended December 31, 2017, 2016 and 2015, we recorded net unrealized gains of $1.0 million, $379,000 and $7,000, 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.

10. GOODWILL AND OTHER INTANGIBLE ASSETS

The carrying value of goodwill as of December 31, 2017 and 2016 was as follows:

	As of December 31,	
(in thousands)	**2017**	**2016**
Regulated Energy	**$ 3,353**	$ 3,353
Unregulated Energy	**18,751**	11,717
Total	**$ 22,104**	$ 15,070

As of December 31, 2017, goodwill in our Regulated Energy segment is comprised of approximately $2.5 million from the FPU merger in October 2009, $170,000 from the purchase of operating assets from IGC in August 2010 and $714,000 from the purchase of Fort Meade in December 2013. As of December 31, 2017, goodwill in our Unregulated Energy segment is comprised of $10.1 million from the acquisition of Gatherco in April 2015, $6.8 million from the acquisition of certain operating assets from ARM in August 2017, and $1.9 million from the acquisition of the operating assets of several propane distribution companies. The annual impairment testing for 2017 and 2016 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2017 and 2016 are as follows:

	As of December 31,			
	2017		**2016**	
(in thousands)	**Gross Carrying Amount**	**Accumulated Amortization**	**Gross Carrying Amount**	**Accumulated Amortization**
Customer lists	**$ 7,393**	**$ 2,880**	$ 4,012	$ 2,379
Non-Compete agreements	**270**	**175**	270	146
Other	**270**	**192**	270	184
Total	**$ 7,933**	**$ 3,247**	$ 4,552	$ 2,709

The customer lists acquired in the purchases of the operating assets of several companies are being amortized over seven to 12 years. The non-compete agreements acquired in the purchase of the operating assets of several companies are being amortized over a six-year or seven-year period. The other intangible assets consist of acquisition costs from our propane distribution acquisitions in the late 1980s and 1990s and are being amortized over 40 years.

For the years ended December 31, 2017, 2016 and 2015, amortization expense of intangible assets was $537,000, $380,000, and $367,000, respectively. Amortization expense of intangible assets is expected to be $790,000 for each of the years 2018, 2019 and 2020, $725,000 for 2021 and $471,000 for 2022.

11. 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 returns for tax years after 2013 are subject to examination.

We had no net operating loss for federal income tax purposes as of December 31, 2017. As of December 31, 2016, we had a net operating loss for federal income tax purposes of $14.0 million, which we carried back two years. For state income tax purposes, we had net operating losses in various states of $34.2 million and $19.6 million as of December 31, 2017 and 2016, respectively, almost all of which will expire in 2036. We have recorded deferred tax assets of $1.6 million and $893,000 related to state net operating loss carry-forwards at December 31, 2017 and 2016, 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 and several technical provisions, including, among others, limiting the utilization of net operating losses arising after December 31, 2017 to 80 percent of taxable income with an indefinite carryforward. Our federal income tax expense for periods beginning on January 1, 2018 will be based on the new federal corporate income tax rate. The specific TCJA provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and continuation of certain rate normalization requirements for accelerated depreciation benefits.

Additionally, enactment of the TCJA resulted in 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 and have made a reasonable estimate of the measurement and accounting of certain effects of the TCJA, which have been reflected in the December 31, 2017 consolidated financial statements, the period in which the TCJA was enacted. At the date of enactment, we re-measured deferred income taxes based upon the new corporate tax rate. For our regulated businesses, the change in deferred income taxes of $98.5 million was recorded as an offset to a regulatory liability, some portion of which may ultimately be subject to refund to customers. We are at various stages of discussion with our regulatory jurisdictions. For our unregulated businesses, the change in deferred income taxes of $14.3 million was recorded as an adjustment to our deferred income taxes and increased our net income.

The following tables provide: (a) the components of income tax expense in 2017, 2016, and 2015; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2017, 2016, and 2015; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2017 and 2016.

	For the Year Ended December 31,		
	2017	**2016**	**2015**
(in thousands)			
Current Income Tax Expense			
Federal	**$ 2,803**	$ (4,898)	$ 4,875
State	**492**	2,053	1,533
Other	**(71)**	(71)	(23)
Total current income tax expense	**3,224**	(2,916)	6,385
Deferred Income Tax Expense [1]			
Property, plant and equipment	**8,314**	31,062	21,205
Deferred gas costs	**2,002**	1,163	(1,539)
Pensions and other employee benefits	**180**	237	(84)
FPU merger-related premium cost and deferred gain	**(1,148)**	(572)	(556)
Net operating loss carryforwards	**193**	(9)	2,078
Other	**1,544**	(624)	(584)
Total deferred income tax expense	**11,085**	31,257	20,520
Total Income Tax Expense	**$ 14,309**	$ 28,341	$ 26,905

[1]Includes $873,000, $2.1 million and $2.1 million of deferred state income taxes for the years 2017, 2016 and 2015, respectively.

(in thousands)	For the Year Ended December 31, 2017	2016	2015
Reconciliation of Effective Income Tax Rates			
Federal income tax expense [1]	**$ 25,351**	$ 22,759	$ 23,865
State income taxes, net of federal benefit	**1,894**	3,422	3,062
ESOP dividend deduction	**(257)**	(264)	(263)
Revaluation of deferred tax assets and liabilities	**(14,299)**	—	—
Other	**1,620**	2,424	241
Total Income Tax Expense	**$ 14,309**	$ 28,341	$ 26,905
Effective Income Tax Rate [2]	**19.75%**	38.81%	39.54%

(1) Federal income taxes were calculated at 35 percent for each year represented.

(2) Effective tax rate for 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, 2017	2016
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	**$ 133,581**	$ 218,074
Acquisition adjustment	**9,323**	14,840
Loss on reacquired debt	**153**	442
Deferred gas costs	**2,574**	1,846
Other	**5,422**	6,375
Total deferred income tax liabilities	**151,053**	241,577
Deferred income tax assets:		
Pension and other employee benefits	**4,698**	6,230
Environmental costs	**1,744**	2,592
Net operating loss carryforwards	**1,625**	952
Investment tax credit carryforwards	**—**	2,643
Self insurance	**164**	189
Storm reserve liability	**717**	1,131
Other	**6,255**	4,946
Total deferred income tax assets	**15,203**	18,683
Deferred Income Taxes Per Consolidated Balance Sheets	**$ 135,850**	$ 222,894

12. LONG-TERM DEBT

Our outstanding long-term debt is shown below:

	As of December 31,	
(in thousands)	**2017**	**2016**
FPU secured first mortgage bonds:		
9.08% bond, due June 1, 2022	**$ 7,982**	$ 7,978
Uncollateralized Senior Notes:		
6.64% note, due October 31, 2017	**—**	2,727
5.50% note, due October 12, 2020	**6,000**	8,000
5.93% note, due October 31, 2023	**18,000**	21,000
5.68% note, due June 30, 2026	**26,100**	29,000
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**	—
Promissory notes	**97**	168
Capital lease obligation	**2,070**	3,471
Less: debt issuance costs	**(433)**	(291)
Total long-term debt	**206,816**	149,053
Less: current maturities	**(9,421)**	(12,099)
Total long-term debt, net of current maturities	**$ 197,395**	$ 136,954

Annual maturities and principal repayments of long-term debt, excluding the capital lease obligation, are as follows: $8.0 million for 2018; $10.6 million for 2019; $15.6 million for 2020; $13.6 million for 2021; $25.1 million for 2022 and $132.3 million thereafter. See Note 14, *Lease Obligations,* for future payments related to the capital lease obligation.

Shelf Agreements

In October 2015, we entered into the Prudential Shelf Agreement, under which we may request that Prudential purchase, through October 8, 2018, up to $150.0 million of Prudential Shelf Notes. The Prudential Shelf Notes have a fixed interest rate and a maturity date not to exceed twenty years from the date of issuance. Prudential is under no obligation to purchase any of the Prudential Shelf Notes. The interest rate and terms of payment of any series of the Prudential Shelf Notes will be determined at the time of purchase.

In May 2016, Prudential agreed to purchase $70.0 million of 3.25 percent Prudential Shelf Notes, which were issued on April 21, 2017. The proceeds received from this issuance of Prudential Shelf Notes were used to reduce short-term borrowings under the Revolver. The balance under the Revolver had accumulated over time as capital expenditures were temporarily financed. As of December 31, 2017, $80 million remains available for issuance under the Prudential Shelf Agreement.

In March 2017, we entered into the MetLife Shelf Agreement and the NYL Shelf Agreement, under which we may request that MetLife and NYL, through March 2, 2020, purchase up to $150.0 million and $100.0 million, respectively, of our unsecured senior debt. The unsecured senior debt would have a fixed interest rate and a maturity date not to exceed twenty years from the date of issuance. MetLife and NYL are under no obligation to purchase any unsecured senior debt. The interest rate and terms of payment of any series of unsecured senior debt will be determined at the time of purchase.

In November 2017, NYL agreed to purchase $50.0 million of 3.48% Series A notes and $50.0 million of 3.58% Series B notes. The Series A notes and Series B notes will be issued on or before May 21, 2018 and November 20, 2018, respectively. The proceeds received from the issuances of these shelf notes will be used to reduce short-term borrowings under the Revolver and/or lines of credit and/or to fund capital expenditures. The NYL Shelf Agreement has been fully utilized.

As of December 31, 2017, we had not requested that MetLife purchase unsecured senior debt under the MetLife Shelf Agreement.

The Prudential Shelf Agreement, the MetLife 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. It provides that FPU cannot make dividends or other restricted payments in excess of the sum of $2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2017, FPU's cumulative net income base was $142.6 million, offset by restricted payments of $37.6 million, leaving $104.9 million of cumulative net income for FPU free of restrictions pursuant to this covenant.

The dividend restrictions in FPU's first mortgage bonds resulted in approximately $43.0 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2017. This represents approximately 9 percent of our consolidated net assets. Other than the dividend restrictions in 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 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 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, 2017, the cumulative consolidated net income base was $387.7 million, offset by restricted payments of $178.0 million), leaving $209.7 million of cumulative net income free of restrictions.

As of December 31, 2017, we are in compliance with all of our debt covenants.

13. SHORT-TERM BORROWINGS

At December 31, 2017 and 2016, we had $251.0 million and $209.9 million, respectively, of short-term borrowings outstanding at the weighted average interest rates of 2.42 percent and 1.43 percent, respectively. In October 2015, we entered into a Credit Agreement with the Lenders for a $150.0 million Revolver through October 2020 subject to the terms and conditions as specified. In November 2017, we entered into a new $40.0 million short-term credit facility with a new lender. As a result, we now 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. We incurred commitment fees of $131,000, $145,000 and $106,000 in 2017, 2016 and 2015, respectively. The following table summarizes our short-term borrowing facilities information at December 31, 2017 and 2016.

(in thousands)	Total Facility	Interest Rate	Expiration Date	Outstanding borrowings at December 31, 2017	Outstanding borrowings at December 31, 2016	Available at December 31, 2017
Bank Credit Facility						
Committed revolving credit facility A	$ 55,000	LIBOR plus 1.00 percent (1)	October 28, 2018	**$ 55,000**	$ 45,000	**$ —**
Committed revolving credit facility B	30,000	LIBOR plus 1.00 percent (1)	October 31, 2018	**20,500**	21,311	**9,500**
Short-term revolving credit note C	50,000	LIBOR plus 0.80 percent (2)	October 31, 2018	**50,000**	50,000	**—**
Committed revolving credit facility D	45,000	LIBOR plus 0.85 percent (3)	October 31, 2018	**40,171**	35,000	**4,829**
Committed revolving credit facility E	40,000	LIBOR plus 0.85 percent (3)	October 31, 2018	**—**	—	**40,000**
Committed revolving credit facility F(5)	150,000	LIBOR plus 1.00 percent (1)	October 08, 2020	**75,000**	50,000	**75,000**
Total short term credit facilities	$ 370,000			**$ 240,671**	$ 201,311	**$ 129,329**
Book overdrafts(4)				**10,298**	8,560	
Total short-term borrowing				**$ 250,969**	$ 209,871	

(1) This facility bears interest at LIBOR for the applicable period plus up to 1.00 percent, based on Total Indebtedness as a percentage of Total Capitalization.

(2) At our discretion, the borrowings under this facility can bear interest at the lender's base rate plus 0.80 percent.

(3) At our discretion, the borrowing under this facility can bear interest at the lender's base rate plus 0.85 percent.

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

(5) 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.

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. We are authorized by our Board of Directors to borrow up to $275.0 million of short-term debt, as required, from these short-term lines of credit. As of February 27, 2018 the Board increased this limit from $275.0 million to $350.0 million.

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.

14. LEASE OBLIGATIONS

We have entered into several operating lease arrangements for office space, equipment and pipeline facilities. Rent expense related to these leases for 2017, 2016 and 2015 was $3.6 million, $2.5 million, and $1.7 million, respectively. As of December 31, 2017, future minimum payments under our current lease agreements for the years 2018 through 2022 are $2.7 million, $1.7 million, $1.0 million, $815,000, and $654,000, respectively and approximately $3.7 million thereafter, with an aggregate total of approximately $10.6 million.

For each of the years ended December 31, 2017, 2016, and 2015, we paid $1.5 million, for a capital lease arrangement related to Sandpiper's capacity, supply and operating agreement. Future minimum payments under this lease arrangement are $1.5 million for 2018 and $625,000 in 2019, with an aggregate total of $2.1 million.

15. STOCKHOLDERS' EQUITY

Preferred Stock

We have 2,000,000 authorized and unissued shares of $0.01 par value preferred stock as of December 31, 2017 and 2016. Shares of preferred stock may be issued from time to time, by authorization of our Board of Directors and without the necessity of further action or authorization by stockholders, in one or more series and with such voting powers, designations, preferences and relative, participating, optional or other special rights and qualifications as the Board of Directors may, in its discretion, determine.

Common Stock Public Offering

In September 2016, we completed a public offering of 960,488 shares of our common stock at a public offering 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, which were added to our general funds and used primarily to repay a portion of our short-term debt under unsecured lines of credit.

Shareholders' Rights

Effective February 27, 2018, we entered into the Amendment to the Rights Agreement to accelerate the expiration of the Rights (as defined below) from 5:00 P.M., New York City time, on August 20, 2019, to 5:00 P.M., New York City time, on February 27, 2018 and, which has the effect of terminating the Rights Agreement on that date. At the time of the termination of the Rights Agreement, all of the Rights distributed to holders of our common stock pursuant to the Rights Agreement will expire by their respective terms. Accordingly, the Rights Agreement is of no further force and effect.

Prior to termination of the Rights Agreement, each outstanding share of our common stock held of record on September 3, 1999, as adjusted for our stock split in September 2014, and additional shares of common stock issued since that time, was accompanied by one preferred stock purchase right (each, a "Right," and, collectively, the "Rights"). Each Right initially entitled the holder to purchase one fiftieth of a share of our Series A Participating Cumulative Preferred Stock, par value $0.01 per share, at a price of $70 per unit, subject to anti-dilution adjustments. Upon a person or entity becoming an Acquiring Person, each Right (other than the Rights held by the Acquiring Person) would have become exercisable to purchase a number of shares of our common stock having a market value equal to two times the exercise price of the Right.

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).

The following tables present the changes in the balance of accumulated other comprehensive loss for the years ended December 31, 2017 and 2016. All amounts in the following tables are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contract 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)**

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2015	$ (5,580)	$ (260)	$ (5,840)
Other comprehensive income/(loss) before reclassifications	(254)	762	508
Amounts reclassified from accumulated other comprehensive income/(loss)	474	(20)	454
Net current-period other comprehensive income	220	742	962
As of December 31, 2016	$ (5,360)	$ 482	$ (4,878)

The following table presents amounts reclassified out of accumulated other comprehensive income (loss) for the years ended December 31, 2017, 2016 and 2015. 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)	**2017**	**2016**	**2015**
Amortization of defined benefit pension and postretirement plan items:			
Prior service cost (1)	**$ 77**	$ 77	$ 68
Net gain (1)	**(636)**	(871)	(650)
Total before income taxes	**(559)**	(794)	(582)
Income tax benefit	**223**	320	233
Net of tax	**$ (336)**	$ (474)	$ (349)
Gains and losses on commodity contracts cash flow hedges			
Propane swap agreements (2)	**$ 1,607**	$ (322)	$ (120)
Natural gas swaps (2)	**(822)**	—	(55)
Natural gas futures (2)	**(456)**	345	(31)
Total before income taxes	**329**	23	(206)
Income tax impact	**(159)**	(3)	83
Net of tax	**$ 170**	$ 20	$ (123)
Total reclassifications for the period	**$ (166)**	$ (454)	$ (472)

(1) These amounts are included in the computation of net periodic benefits. See Note 16, *Employee Benefit Plans*, for additional details.
(2) These amounts are included in the effects of gains and losses from derivative instruments. See Note 7, *Derivative Instruments*, for additional details.

Amortization of defined benefit pension and postretirement plan items is included in operations expense, 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.

16. 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 as an asset or a liability on our consolidated balance sheets. 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 SERP.

The Chesapeake Pension 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 unfunded liability for the Chesapeake Pension Plan of approximately $2.1 million and $2.7 million at December 31, 2017 and 2016, is included in the other pension and benefit costs liability in our consolidated balance sheets.

The FPU Pension 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 unfunded liability for the FPU Pension Plan of approximately $16.3 million and $20.6 million at December 31, 2017 and 2016, respectively, is included in the other pension and benefit costs liability in our consolidated balance sheets.

The Chesapeake SERP 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 unfunded liability for the Chesapeake SERP of approximately $2.4 million, at both December 31, 2017 and 2016, 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, 2017 and 2016 and the net periodic cost for the years ended December 31, 2017, 2016 and 2015 for the Chesapeake and FPU Pension Plans:

	Chesapeake Pension Plan		FPU Pension Plan	
At December 31,	**2017**	**2016**	**2017**	**2016**
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	**$ 11,355**	$ 11,501	**$ 63,832**	$ 64,435
Interest cost	**402**	421	**2,482**	2,525
Actuarial loss (gain)	**454**	330	**1,199**	(216)
Effect of settlement	**—**	(433)	**—**	—
Benefits paid	**(768)**	(464)	**(2,849)**	(2,912)
Benefit obligation — end of year	**11,443**	11,355	**64,664**	63,832
Change in plan assets:				
Fair value of plan assets — beginning of year	**8,668**	8,752	**43,272**	42,207
Actual return on plan assets	**1,144**	424	**6,025**	2,343
Employer contributions	**306**	389	**1,948**	1,634
Benefits paid	**(768)**	(464)	**(2,849)**	(2,912)
Effect of settlement	**—**	(433)	**—**	—
Fair value of plan assets — end of year	**9,350**	8,668	**48,396**	43,272
Reconciliation:				
Funded status	**(2,093)**	(2,687)	**(16,268)**	(20,560)
Accrued pension cost	**$ (2,093)**	$ (2,687)	**$ (16,268)**	$ (20,560)
Assumptions:				
Discount rate	**3.50%**	3.75%	**3.75%**	4.00%
Expected return on plan assets	**6.00%**	6.00%	**6.50%**	6.50%

	Chesapeake Pension Plan			FPU Pension Plan		
For the Years Ended December 31,	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
(in thousands)						
Components of net periodic pension cost:						
Interest cost	**$ 402**	$ 421	$ 407	**$ 2,482**	$ 2,525	$ 2,504
Expected return on assets	**(495)**	(501)	(530)	**(2,779)**	(2,702)	(3,107)
Amortization of actuarial loss	**399**	459	392	**513**	519	456
Settlement expense	**—**	161	—	**—**	—	—
Net periodic pension cost	**306**	540	269	**216**	342	(147)
Amortization of pre-merger regulatory asset	**—**	—	—	**761**	761	761
Total periodic cost	**$ 306**	$ 540	$ 269	**$ 977**	$ 1,103	$ 614
Assumptions:						
Discount rate	**3.75%**	3.75%	3.50%	**4.00%**	4.00%	3.75%
Expected return on plan assets	**6.00%**	6.00%	6.00%	**6.50%**	6.50%	7.00%

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 $1.3 million and $2.1 million at December 31, 2017 and 2016, respectively.

The following sets forth the funded status at December 31, 2017 and 2016 and the net periodic cost for the years ended December 31, 2017, 2016 and 2015 for the Chesapeake SERP:

At December 31,	**2017**	**2016**
(in thousands)		
Change in benefit obligation:		
Benefit obligation — beginning of year	**$ 2,428**	$ 2,510
Interest cost	**89**	91
Actuarial loss (gain)	**63**	(21)
Benefits paid	**(152)**	(152)
Benefit obligation — end of year	**2,428**	2,428
Change in plan assets:		
Fair value of plan assets — beginning of year	**—**	—
Employer contributions	**152**	152
Benefits paid	**(152)**	(152)
Fair value of plan assets — end of year	**—**	—
Reconciliation:		
Funded status	**(2,428)**	(2,428)
Accrued pension cost	**$ (2,428)**	$ (2,428)
Assumptions:		
Discount rate	**3.50%**	3.75%

For the Years Ended December 31, *(in thousands)*	**2017**	**2016**	**2015**
Components of net periodic pension cost:			
Interest cost	**$ 89**	$ 91	$ 91
Amortization of prior service cost	**—**	—	9
Amortization of actuarial loss	**87**	87	99
Net periodic pension cost	**$ 176**	$ 178	$ 199
Assumptions:			
Discount rate	**3.75%**	3.75%	3.50%

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, 2017, 2016 and 2015:

	Chesapeake Pension Plan			**FPU Pension Plan**		
At December 31,	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Asset Category						
Equity securities	**52.70%**	52.93%	48.01%	**55.17%**	53.18%	48.56%
Debt securities	**37.79%**	37.64%	39.62%	**36.56%**	37.74%	41.74%
Other	**9.51%**	9.43%	12.37%	**8.27%**	9.08%	9.70%
Total	**100.00%**	100.00%	100.00%	**100.00%**	100.00%	100.00%

The investment policy of both the Chesapeake 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, 2017 and 2016, 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, 2017				At December 31, 2016			
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)]	**$ 4,245**	**$ —**	**$ —**	**$ 4,245**	$ 4,031	$ —	$ —	$ 4,031
U.S. Mid Cap [(1)]	**1,775**	**—**	**—**	**1,775**	1,677	—	—	1,677
U.S. Small Cap [(1)]	**918**	**—**	**—**	**918**	845	—	—	845
International [(2)]	**11,916**	**—**	**—**	**11,916**	9,574	—	—	9,574
Alternative Strategies [(3)]	**5,528**	**—**	**—**	**5,528**	5,238	—	—	5,238
	24,382	**—**	**—**	**24,382**	21,365	—	—	21,365
Mutual Funds - Debt securities								
Fixed income [(4)]	**18,454**	**—**	**—**	**18,454**	16,958	—	—	16,958
High Yield [(4)]	**2,772**	**—**	**—**	**2,772**	2,636	—	—	2,636
	21,226	**—**	**—**	**21,226**	19,594	—	—	19,594
Mutual Funds - Other								
Commodities [(5)]	**2,154**	**—**	**—**	**2,154**	2,134	—	—	2,134
Real Estate [(6)]	**2,300**	**—**	**—**	**2,300**	2,116	—	—	2,116
Guaranteed deposit [(7)]	**—**	**—**	**436**	**436**	—	—	498	498
	4,454	**—**	**436**	**4,890**	4,250	—	498	4,748
Total Pension Plan Assets in fair value hierarchy	**$ 50,062**	**$ —**	**$ 436**	**50,498**	$ 45,209	$ —	$ 498	45,707
Investments measured at net asset value [(8)]				**7,248**				6,233
Total Pension Plan Assets				**$ 57,746**				$ 51,940

(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, 2017 and 2016, all of the investments were classified under the same fair value measurement hierarchy (Level 1 through Level 3) described under Note 8, *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, 2017 and 2016:

	For the Year Ended December 31,	
	2017	2016
(in thousands)		
Balance, beginning of year	**$ 498**	$ 1,286
Purchases	**2,271**	2,023
Transfers in	**1,743**	1,435
Disbursements	**(4,101)**	(4,268)
Investment income	**25**	22
Balance, end of year	**$ 436**	$ 498

Other Postretirement Benefits Plans

We sponsor two defined benefit plans: the Chesapeake Postretirement Plan and the FPU Medical Plan. The following table sets forth the funded status at December 31, 2017 and 2016 and the net periodic cost for the years ended December 31, 2017, 2016, and 2015:

	Chesapeake Postretirement Plan		FPU Medical Plan	
At December 31,	2017	2016	2017	2016
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	**$ 1,132**	$ 1,153	**$ 1,349**	$ 1,444
Interest cost	**41**	43	**50**	55
Plan participants contributions	**118**	90	**48**	64
Actuarial loss (gain)	**72**	20	**(48)**	(41)
Benefits paid	**(235)**	(174)	**(112)**	(173)
Benefit obligation — end of year	**1,128**	1,132	**1,287**	1,349
Change in plan assets:				
Fair value of plan assets — beginning of year	**—**	—	**—**	—
Employer contributions[1]	**117**	84	**64**	109
Plan participants contributions	**118**	90	**48**	64
Benefits paid	**(235)**	(174)	**(112)**	(173)
Fair value of plan assets — end of year	**—**	—	**—**	—
Reconciliation:				
Funded status	**(1,128)**	(1,132)	**(1,287)**	(1,349)
Accrued postretirement cost	**$ (1,128)**	$ (1,132)	**$ (1,287)**	$ (1,349)
Assumptions:				
Discount rate	**3.50%**	3.75%	**3.75%**	4.00%

(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 2017, 2016, and 2015 include the following components:

	Chesapeake Postretirement Plan			FPU Medical Plan		
For the Years Ended December 31, *(in thousands)*	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Components of net periodic postretirement cost:						
Interest cost	**$ 41**	$ 43	$ 42	**$ 50**	$ 55	$ 57
Amortization of:						
Actuarial loss	**53**	64	72	**—**	—	—
Prior service cost	**(77)**	(77)	(77)	**—**	—	—
Net periodic cost	**17**	30	37	**50**	55	57
Amortization of pre-merger regulatory asset	**—**	—	—	**8**	8	8
Net periodic cost	**$ 17**	$ 30	$ 37	**$ 58**	$ 63	$ 65
Assumptions						
Discount rate	**3.75%**	3.75%	3.50%	**4.00%**	4.00%	3.75%

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 $22,000 and $30,000 at December 31, 2017 and 2016, 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, 2017:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ —	$ —	$ —	$ (601)	$ —	$ (601)
Net loss	3,629	17,483	733	767	10	22,622
Total	$ 3,629	$ 17,483	$ 733	$ 166	$ 10	$ 22,021
Accumulated other comprehensive loss pre-tax[1]	$ 3,629	$ 3,322	$ 733	$ 166	$ 2	$ 7,852
Post-merger regulatory asset	—	14,161	—	—	8	14,169
Subtotal	3,629	17,483	733	166	10	22,021
Pre-merger regulatory asset	—	1,304	—	—	22	1,326
Total unrecognized cost	$ 3,629	$ 18,787	$ 733	$ 166	$ 32	$ 23,347

(1) The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2017 is net of income tax benefits of $3.1 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.

The amounts in accumulated other comprehensive loss and recorded as a regulatory asset for our pension and postretirement benefits plans that are expected to be recognized as a component of net periodic benefit cost in 2018 are set forth in the following table:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ —	$ —	$ —	$ (77)	$ —	$ (77)
Net loss	$ 351	$ 434	$ 101	$ 58	$ —	$ 944
Amortization of pre-merger regulatory asset	$ —	$ 761	$ —	$ —	$ 8	$ 769

Assumptions

The assumptions used for the discount rate to calculate the benefit obligations of all the plans were based on the interest rates of high-quality bonds in 2017, reflecting the expected lives 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 2017 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. A one-percentage point increase in the health care inflation rate from the assumed rate would increase the accumulated postretirement benefit obligation by approximately $277,000 as of December 31, 2017, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2017 by approximately $11,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $215,000 as of December 31, 2017, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2017 by approximately $8,000.

Estimated Future Benefit Payments

In 2018, we expect to contribute $359,000 and $1.5 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $151,000 to the Chesapeake SERP. We also expect to contribute $97,000 and $88,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2017. 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)
2018	$ 687	$ 3,078	$ 151	$ 97	$ 88
2019	$ 490	$ 3,207	$ 150	$ 96	$ 94
2020	$ 675	$ 3,304	$ 149	$ 85	$ 87
2021	$ 779	$ 3,362	$ 385	$ 82	$ 91
2022	$ 592	$ 3,536	$ 146	$ 81	$ 93
Years 2023 through 2027	$ 5,278	$ 18,608	$ 738	$ 290	$ 404

(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, 2017, 2016 and 2015, 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 six percent. In 2018, the maximum automatic deferral rate will be increased to 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 $5.0 million, $4.5 million, and $4.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017, 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 executive 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 executive officers can defer up to 80 percent of their base compensation, cash bonuses or any amount of their stock bonuses (net of required withholdings). Executive 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 benefits to begin on a specified future date or upon separation from service. Additionally, participants can elect to receive payments upon the earlier of a fixed date or separation from service or they can elect to receive payment upon the 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 had a fair value of $6.7 million and $4.9 million at December 31, 2017 and 2016, respectively. (See *Note 9, Investments*, for further details). The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Deferrals of executive 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 $3.4 million and $2.4 million at December 31, 2017 and 2016, respectively.

17. 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 509,202 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, 2017, 2016 and 2015:

	For the Year Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Awards to non-employee directors	**$ 540**	$ 580	$ 640
Awards to key employees	**1,950**	1,787	1,297
Total compensation expense	**2,490**	2,367	1,937
Less: tax benefit	**(1,003)**	(952)	(780)
Share-based compensation amounts included in net income	**$ 1,487**	$ 1,415	$ 1,157

Stock Options

We did not have any stock options outstanding at December 31, 2017 or 2016, nor were any stock options issued during the years 2015 through 2017.

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. A summary of stock activity for our non-employee directors for the years ended December 31, 2017 and 2016 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding — December 31, 2015	—	$ —
Granted	8,577	$ 62.90
Vested	(8,577)	$ 62.90
Outstanding — December 31, 2016	—	$ —
Granted	7,515	$ 71.80
Vested	(7,515)	$ 71.80
Outstanding — December 31, 2017	—	$ —

The weighted average grant date fair value of shares granted to our non-employee directors during 2017, 2016 and 2015 was $71.80, $62.90 and $45.54 per share, respectively. 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, 2017, there was $179,000 of unrecognized compensation expense related to these awards. This expense will be fully recognized by April 2018, 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. These awards are subject to certain post-vesting transfer restrictions.

We currently have outstanding several multi-year performance plans, which are based upon the successful achievement of long-term goals, growth and financial results which comprise both market-based and performance-based conditions or targets. The fair value of each share of stock, tied to a performance-based condition or target, is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each share of market-based award 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, 2015	110,398	$ 38.34
Granted	46,571	$ 67.90
Vested	(39,553)	$ 31.79
Expired	(2,325)	$ 42.25
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**	**$ 53.00**

In 2017, 2016 and 2015, 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 total number of shares withheld of 10,269, 12,031 and 12,620 for 2017, 2016 and 2015, respectively, were based on the closing price of the shares on their award date. Total payments for the employees' tax obligations to the taxing authorities were approximately $692,000, $770,000 and $592,000, in 2017, 2016 and 2015, respectively. The tax benefits associated with these obligations for 2017, 2016 and 2015 are $349,000, $285,000, and $297,000, respectively. The tax benefit for 2015 was recorded in additional paid-in capital in the consolidated statements of stockholders' equity. The tax benefit for 2017 and 2016 was included in the statements of income due to the adoption of new accounting guidance.

The weighted average grant-date fair value of shares granted to key employees during 2017, 2016 and 2015 was $63.42, $67.90 and $47.65 per share, respectively. The intrinsic value of these awards was $10.4 million, $7.7 million and $6.3 million in 2017, 2016 and 2015, respectively. At December 31, 2017, there was $2.3 million of unrecognized compensation cost related to these awards, which is expected to be recognized during 2018 through 2019.

18. 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. Chesapeake Utilities' Florida Division and FPU's natural gas and electric distribution operations continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

Rate Case Filing: In December 2015, our Delaware Division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. The Delaware Division, Delaware PSC Staff, the Division of the Public Advocate and other intervenors met and reached a settlement agreement in November 2016. The terms of the settlement agreement included an annual increase of approximately $2.3 million in base rates. The order became final in December 2016, and the new rates became effective January 1, 2017. Amounts collected through interim rates in excess of the respective portion of the $2.3 million increase through December 31, 2016 were accrued as of that date. In January 2017, we filed our proposed refund plan with the Delaware PSC and subsequently issued refunds to customers in March 2017.

Effect of the TCJA on rate payers: As result of the enactment of the TCJA, the Delaware PSC issued an order requiring all rate-regulated utilities to file estimates of their determination of the impact of the TCJA on their cost of service for the most recent test year available (including new rate schedules). The order also requires utilities to propose procedures for changing rates to reflect those impacts on or before March 31, 2018. Our Delaware Division is assessing the impact of the TCJA and will file the requisite reports with the Delaware PSC. If, after reviewing the required filing, the Delaware PSC determines to reduce our rates, it will open a new docket and establish a procedural schedule for conducting an evidentiary hearing regarding the impacts of the TCJA on our operations and existing rates. We believe that the ultimate resolution of this matter will not have a material impact on our financial position or results of operations.

In addition, the Division of the Public Advocate filed a Motion to direct regulated public utilities to accrue regulatory liabilities, starting February 1, 2018, to reflect the Delaware jurisdictional revenue requirement impacts of the changes in the federal corporate income tax rate effected by the TCJA. On February 1, 2018, the PSC issued an order requiring Delaware rate-regulated public utilities to accrue regulatory liabilities reflecting the jurisdictional revenue requirement impacts of the changes in the federal corporate income tax laws.

Maryland Division and Sandpiper

Effect of the TCJA on rate payers: The Maryland PSC issued an order requiring all Maryland public utilities whose rates are explicitly grossed-up for income taxes to track the impacts of the TCJA beginning January 1, 2018. The order required utilities to: (a) apply regulatory accounting treatment, which includes the use of regulatory assets and liabilities for all impacts of the TCJA; (b) file, on or before February 15, 2018, an explanation of the expected effects of the TCJA on their expenses and revenues; and (c) explain when and how they expect to pass on to their customers the net results of those effects. Our Maryland division and Sandpiper prepared filings that included preliminary estimates of the annual impact of the change in the statutory federal income tax rate from 35 percent to 21 percent and also requested that the Maryland PSC grant us additional time to finalize our calculations. We will be recommending appropriate treatment and/or amortization periods for the regulatory liabilities created from the deferred tax revaluation.

Florida

Cost Recovery for the Electric Interconnect Project: In September 2015, FPU's electric division filed to recover the cost of the proposed FPL interconnect project through FPU's annual Fuel and Purchased Power Cost Recovery Clause filing. The interconnect project would enable FPU's electric division to negotiate a new power purchase agreement to mitigate fuel costs for its Northeast division. FPU's proposal was approved by the Florida PSC at its Agenda Conference held in December 2015. In January 2016, however, the Office of Public Counsel filed an appeal of the Florida PSC's decision with the Florida Supreme Court. The Florida Supreme Court reversed the Florida PSC decision in March 2017, after consideration of the parties' legal briefs and oral arguments. As a result, FPU excluded the recovery of these costs from its 2018 Fuel and Purchased Power Cost Recovery Clause and included the costs for recovery in the limited proceeding filing described below.

Surcharge Associated with Modernization of Electric Distribution System Project: In February 2017, FPU's electric division filed a petition with the Florida PSC requesting a temporary surcharge mechanism to recover costs and generate an appropriate return on investment associated with an essential reliability and modernization project for its electric distribution system. FPU requested approval to invest approximately $59.8 million, over a five-year period, associated with the modernization project. In February 2017, the Office of Public Counsel intervened in this petition. The Florida PSC requested that FPU file a limited proceeding to include these investments in base rates instead of seeking approval of a temporary surcharge. In April 2017, FPU voluntarily withdrew its petition and subsequently filed the limited proceeding described in the next paragraph.

Electric Limited Proceeding: In July 2017, FPU's electric division 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 FPU's grid. Included in the $15.2 million is the interconnection project with FPL, which enables FPU to mitigate fuel costs for its electric customers. In December 2017, the Florida PSC approved this petition with an effective date of January 1, 2018. The settlement agreement prescribes 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.

Northwest Florida Expansion Project: Peninsula Pipeline and our Florida Division are constructing a pipeline in Escambia County, Florida, that will interconnect with FGT's pipeline. The project consists of 33 miles of 12-inch transmission line from the FGT interconnect that will be operated by Peninsula Pipeline and eight miles of 8-inch lateral distribution line that will be operated by Chesapeake Utilities' Florida Division. We have entered into agreements to serve two large customers and are marketing to other customers located close to the facilities.

New Smyrna Beach, Florida Project: In 2017, Peninsula Pipeline constructed a pipeline in Volusia County, Florida, that interconnects with FGT's pipeline. The project, which was placed into service in the fourth quarter of 2017, consists of 14 miles of transmission line from the FGT interconnect operated by Peninsula Pipeline and serves FPU's natural gas distribution system.

(Palm Beach County) Belvedere, Florida Project

Peninsula Pipeline is constructing a pipeline in Palm Beach County, Florida that will interconnect with FGT's pipeline. The project consists of approximately two miles of transmission pipe that will bring gas directly to FPU's distribution system in West Palm Beach. This interconnection, which will be operated by Peninsula Pipeline, will bring gas directly to FPU's distribution system in the vicinity of Belvedere Road and Sonsbury Way in West Palm Beach, Florida. This expansion is expected to be placed into service by the end of the third quarter of 2018.

Effect of the TCJA on rate payers: The Office of Public Counsel filed a petition requesting the Florida PSC to establish a general docket to investigate and adjust rates for all investor-owned utilities related to the passage of the TCJA. The Florida PSC issued a Memorandum with a recommendation that, if utilities do not agree to a January 1, 2018 effective date, then the effective date should be February 6, 2018. On January 30, 2018, the Florida PSC scheduled informal meetings between its staff and interested persons to discuss the impact of TCJA. Meetings to discuss the impact of the TCJA for natural gas utilities, electric utilities and water and wastewater utilities have been scheduled individually in mid-February 2018. In the case of our FPU electric division, an order was issued in December regarding the limited proceeding, which prescribes the applicability, timing and treatment of the implications of tax reform. We believe that the ultimate resolution of this matter will not have a material impact on our financial position or results of operations.

Eastern Shore

White Oak Mainline Expansion Project: In July 2016, Eastern Shore received FERC authorization to construct, own and operate certain expansion facilities designed to provide 45,000 Dts/d of firm transportation service to an electric power generator in Kent County, Delaware. Eastern Shore constructed approximately 5.4 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and increased compression capability at Eastern Shore's existing Delaware City compressor station in New Castle County, Delaware. At the end of March 2017, the entire project was placed into service. The total cost to complete the project was approximately $42.0 million.

System Reliability Project: In September 2016, the FERC approved Eastern Shore's application to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware, and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposed to reinforce critical points on its pipeline system. Previously, in July 2016, the FERC granted Eastern Shore's pre-determination of rolled-in rate treatment absent any significant change in circumstances. As of June 2017, the entire project was placed into service. The total cost to complete the project was approximately $38.0 million. We began to recover the project's costs in August 2017, coinciding with the proposed effectiveness of new rates, subject to refund, pending final resolution of the base rate case described below.

2017 Expansion Project: In May 2016, FERC approved Eastern Shore's request to initiate the pre-filing review process for its 2017 Expansion Project. The 2017 Expansion Project's 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 with an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities.

In December 2016, Eastern Shore submitted an application for a CP authorizing construction of the expansion facilities, which the FERC issued in October 2017. The estimated cost of the 2017 Expansion Project is approximately $117.0 million. In December 2017, the TETLP interconnect was placed into service, as requested. The remaining segments of the Expansion Project are expected to be placed into service in various phases over the second through fourth quarters of 2018.

2017 Rate Case Filing: In January 2017, Eastern Shore filed a base rate proceeding with the FERC, as required by the terms of its 2012 rate case settlement agreement. Eastern Shore's proposed rates were based on the mainline cost of service of approximately $60.0 million, resulting in an overall requested revenue increase of approximately $18.9 million and a requested rate of return on common equity of 13.75 percent. In March 2017, the FERC issued an order suspending the tariff rates for the usual five-month period.

On August 1, 2017, Eastern Shore implemented new rates, subject to refund based upon 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 until the rate case settlement is approved by the FERC and customers receive refunds according to the terms of the settlement agreement. Eastern Shore filed an uncontested settlement agreement and a motion to place interim settlement rates into effect on January 1, 2018. In December 2017, FERC issued an order approving the implementation of interim settlement rates. Not considering the effects of the TCJA, base rates will increase, on an annual basis, by approximately $9.8 million. On February 28, 2018, FERC approved the settlement agreement by a letter order. The order will be deemed final upon the expiration of the right to rehearing on March 30, 2018. Eastern Shore will recover the costs of its 2016 System Reliability Project (placed into service in 2017), along the cost of investments and expenses associated with various expansion, reliability and safety initiatives.

Effect of the TCJA on rate payers: As set forth in the settlement agreement filed with the FERC in the rate case, Eastern Shore agreed to make a filing to reflect the change in the federal corporate income tax rate. Any excess accumulated deferred income tax balances would flow back to customers over the period determined in the next rate case, absent any transition rule included in the TCJA or other statutes or rules that would govern the flow-back period. We believe that the ultimate resolution of this matter will not have a material impact on our financial position or results of operations.

At December 31, 2017 and 2016, 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)	**2017**	2016
Regulatory Assets		
Under-recovered purchased fuel and conservation cost recovery [(1)]	**$ 9,869**	$ 5,703
Under-recovered GRIP revenue [(2)]	**164**	1,469
Deferred postretirement benefits [(3)]	**15,498**	18,379
Deferred conversion and development costs [(1)]	**11,735**	8,051
Environmental regulatory assets and expenditures [(4)]	**3,222**	3,694
Acquisition adjustment [(5)]	**39,992**	41,864
Loss on reacquired debt [(6)]	**1,031**	1,145
Other	**4,994**	4,192
Total Regulatory Assets	**$ 86,505**	$ 84,497
Regulatory Liabilities		
Self-insurance [(7)]	**$ 1,013**	$ 987
Over-recovered purchased fuel and conservation cost recovery [(1)]	**2,048**	808
Under-recovered GRIP revenue [(2)]	**2,245**	—
Storm reserve [(7)]	**669**	2,310
Accrued asset removal cost [(8)]	**40,948**	39,826
Deferred income taxes due to rate change [(9)]	**98,492**	—
Other	**2,048**	424
Total Regulatory Liabilities	**$ 147,463**	$ 44,355

(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 and Chesapeake Utilities' Florida 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 16, *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 19, *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 $1.3 million of the premium paid by FPU, $34.2 million of the premium paid by us in 2009, including the gross up of the amount 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 11, *Income Taxes*, for additional information.

19. 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. Those sites are 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 another former MGP site located in Cambridge, Maryland.

As of December 31, 2017, we had approximately $9.6 million in environmental liabilities, related to FPU's MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites. 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. Approximately $11.0 million has been recovered as of December 31, 2017, leaving approximately $3.0 million in regulatory assets for future recovery of environmental costs 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:

Jurisdiction	MGP Site	Status	Cost to Clean up	Recovery through Rates
Florida	West Palm Beach	Remedial actions approved by FDEP 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.	Yes
Florida	Sanford	In January 2007, FPU and the Sanford group signed a Third Participation Agreement. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000, which has been paid to an escrow account. The EPA issued a preliminary close-out report in December 2014. Groundwater monitoring and statutory five-year reviews to ensure performance of the approved remedy will continue on this site.	FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be approximately $24,000.	Yes
Florida	Winter Haven	Remediation is ongoing.	Not expected to exceed $425,000, which includes costs of implementing institutional controls at the site.	Yes
Delaware	Seaford	Proposed plan for implementation approved by DNREC in July 2017.	$273,000 to $465,000.	Yes
Maryland	Cambridge	Currently in discussions with MDE.	Unable to estimate.	N/A

20. OTHER COMMITMENTS AND CONTINGENCIES

Natural Gas, Electric and Propane Supply

We have entered into contractual commitments to purchase natural gas, electricity and propane from various suppliers. The contracts have various expiration dates. In 2017, our Delmarva Peninsula natural gas distribution operations entered into asset management agreements with PESCO to manage a portion of 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 EGWIC to purchase propane over a six -year term ending in May 2019. Sandpiper's current annual commitment is estimated at approximately 2.7 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 over a six-year term ending in May 2019. Sharp's current annual commitment is estimated at approximately 2.7 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC, and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified 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 fuel 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 this ratio is not met by FPU, it must provide an irrevocable letter of credit or pay all amounts outstanding under the agreement within five business days. FPU’s electric fuel 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, 2017, 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 its retail electric customers. In July 2016, Eight Flags also started selling steam, pursuant to a separate 20-year contract, to Rayonier, the land owner 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 approximately $152.9 million for 2018, $122.8 million for 2019-2020, $44.6 million for 2021-2022 and $149.6 million thereafter.

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 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, 2017 was $72.0 million, with the guarantees expiring on various dates through December 2018.

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 12, *Long-Term Debt*, for further details).

As of December 31, 2017, we have issued letters of credit totaling approximately $5.0 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 2018. There have been no draws on these letters of credit as of December 31, 2017. 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.

21. 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			
	March 31	June 30	September 30	December 31
(in thousands except per share amounts)				
2017 [1]				
Operating Revenues	**$ 185,160**	**$ 125,084**	**$ 126,936**	**$ 180,403**
Operating Income	**$ 34,676**	**$ 13,666**	**$ 14,239**	**$ 23,263**
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**
2016 [1]				
Operating Revenues	$ 146,296	$ 102,342	$ 108,348	$ 141,874
Operating Income	$ 36,380	$ 15,742	$ 10,156	$ 21,819
Net Income	$ 20,367	$ 8,029	$ 4,416	$ 11,863
Earnings per share:				
Basic	$ 1.33	$ 0.52	$ 0.29	$ 0.73
Diluted	$ 1.33	$ 0.52	$ 0.29	$ 0.73

(1) The sum of the four quarters does not equal the total 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 15d – 15(e) promulgated under the Securities Exchange Act of 1934, as amended) as of December 31, 2017. 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, 2017.

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, 2017, 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, 2017. In addition, on June 1, 2017, our 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 principal executive officer and principal 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, 2017.

Our independent auditors, Baker Tilly Virchow Krause, LLP, have audited the effectiveness of our internal control over financial reporting as of December 31, 2017, as stated in their report which appears under Part II, *Item 8. Financial Statements and Supplementary Data*.

ITEM 9B. OTHER INFORMATION.

Effective February 27, 2018, we entered into the Amendment to the Rights Agreement. The Amendment accelerates the expiration of the Rights from 5:00 P.M., New York City time, on August 20, 2019, to 5:00 P.M., New York City time, on February 27, 2018, and has the effect of terminating the Rights Agreement on that date. At the time of the termination of the Rights Agreement, all of the Rights distributed to holders of our common stock pursuant to the Rights Agreement will expire by their respective terms. Accordingly, the Rights Agreement is of no further force and effect.

In connection with the expiration of the Rights Agreement described above, our Board of Directors approved the filing of a Certificate of Elimination (the “Certificate of Elimination”) to eliminate from our Amended and Restated Certificate of Incorporation, as amended, the Certificate of Voting Powers, Designation, Preferences and Relative Participating Common Optional and Other Special Rights and Qualifications, Limitations, or Restrictions of Series A Participating Cumulative Preferred Stock (the “Certificate of Designation”) with the Secretary of State for the State of Delaware on February 28, 2018.

The foregoing are summaries of the terms of the Amendment and the Certificate of Elimination. These summaries do not purport to be complete and are qualified in their entirety by reference to the Amendment and the Certificate of Elimination, copies of which are attached as Exhibits 4.13 and 3.6, respectively, and are incorporated herein by reference.

PART III

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

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 section of our Proxy Statement captioned “Security Ownership of Certain Beneficial Owners and Management.”

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 1.1 — Underwriting Agreement entered into by Chesapeake Utilities Corporation and Wells Fargo Securities, LLC, RBC Capital Markets, LLC, Janney Montgomery Scott LLC., Robert W. Baird & Co., Incorporated, J.J.B. Hilliard, W.L. Lyons, LLC, Ladenburg Thalmann & Co. Inc., U.S. Capital Advisors LLC and BB&T Securities, LLC on September 22, 2016, relating to the sale and issuance of 835,207 shares of the Company's common stock, is incorporated herein by reference to Exhibit 1.1 of the Company's current report on Form 8-K, filed on September 28, 2016, File No. 001-11590.
- 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 filed herewith.
- Exhibit 4.1 — Note Agreement dated October 31, 2002, between Chesapeake Utilities Corporation, as issuer, and Massachusetts Mutual Life Insurance Company, C.M. Life Insurance Company, American United Life Insurance Company, Pioneer Mutual Life Insurance Company and The State Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 6.64% Senior Notes due 2017, is incorporated herein by reference to Exhibit 2 of our Current Report on Form 8-K, filed November 6, 2002, File No. 001-11590.
- Exhibit 4.2 — 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 4.3 — 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 4.4 — 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 4.5 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 4.6 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 4.7 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 period ended March 31, 2011, File No. 001-11590.
- Exhibit 4.8 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 4.9 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, 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 4.10 Private Shelf Agreement dated October 8, 2015, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management Inc., relating to the purchase of Chesapeake Utilities Corporation unsecured Senior Notes, 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 4.11 Rights Agreement, dated August 20, 1999, by and between Registrant and BankBoston, N.A., as rights agent, is incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed on August 24, 1999, File No. 001-11590.
- Exhibit 4.12 First Amendment to Rights Agreement, dated September 12, 2008, by and between Registrant and Computershare Trust Company, N.A., as successor rights agent, is incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed on September 12, 2008, File No. 001-11590.
- Exhibit 4.13 Second Amendment to Rights Agreement by and between Chesapeake Utilities Corporation and Computershare Trust Company, N.A., dated as of February 27, 2018 is filed herewith.
- 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 period 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 period 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 December 29, 2014, between Chesapeake Utilities Corporation and Citizens Bank, National Association, as lender, is incorporated herein by reference to Exhibit 10.25 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
- Exhibit 10.17 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 10.18 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 10.19 Promissory Note, contained as an exhibit to the Revolving Credit Agreement dated December 29, 2014, between Chesapeake Utilities Corporation and Citizens Bank, National Association, as lender, is incorporated herein by reference to Exhibit 10.26 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.

- Exhibit 10.20* 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 10.21* 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 12 Computation of Ratio of Earning to Fixed Charges 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/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President and Chief Executive Officer
February 28, 2018

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/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President, Chief Executive Officer and Director
February 28, 2018

/S/ BETH W. COOPER
Beth W. Cooper, Senior Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)
February 28, 2018

/S/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Chair of the Board and Director
February 28, 2018

/S/ RONALD G. FORSYTHE, JR.
Dr. Ronald G. Forsythe, Jr., Director
February 28, 2018

/S/ EUGENE H. BAYARD, ESQ
Eugene H. Bayard, Esq., Director
February 28, 2018

/S/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
February 28, 2018

/S/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
February 28, 2018

/S/ DIANNA F. MORGAN
Dianna F. Morgan, Director
February 28, 2018

/S/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
February 28, 2018

/S/ CALVERT A. MORGAN, JR.
Calvert A. Morgan, Jr., Director
February 28, 2018

/S/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
February 28, 2018

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					
2017	**$ 909**	**$ 602**	**$ 337**	**$ (912)**	**$ 936**
2016	$ 909	$ 985	$ 340	$ (1,325)	$ 909
2015	$ 1,120	$ 979	$ 246	$ (1,436)	$ 909

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