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

FORM 10-K

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

For the Fiscal Year Ended: December 31, 2016

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, or a smaller reporting company. See the definitions of "accelerated filer," "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller Reporting Company	☐

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, 2016, 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 $975.6 million.

The number of shares of Chesapeake Utilities Corporation's common stock outstanding as of February 20, 2017 was 16,308,449.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2017 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III.

CHESAPEAKE UTILITIES CORPORATION

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YEAR ENDED DECEMBER 31, 2016

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GLOSSARY OF DEFINITIONS

AFUDC: Allowance for funds used during construction

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

BravePoint: BravePoint, Inc., the formerly owned advanced information services subsidiary of Chesapeake Utilities, which was sold on October 1, 2014

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

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

CGC: Consumer Gas Cooperative, an Ohio natural gas cooperative

CHP: Combined heat and power plant

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

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

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

DNREC: Delaware Department of Natural Resources and Environmental Control

Dt: Dekatherm, 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, which owns a CHP plant on Amelia Island, Florida

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

Fort Meade: Fort Meade natural gas division of 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 Florida customers to recover capital and other program-related costs associated with the replacement of qualifying distribution mains and services in Florida

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

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 on October 8, 2015

MDE: Maryland Department of Environment

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

MWH: Megawatt hour, which is a unit of measurement for electricity

Non-Qualified Deferred Compensation Plan: A non-qualified, deferred compensation arrangement 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 base compensation, executive cash bonuses, executive performance shares, and directors' retainers and fees

NYSE: New York Stock Exchange

OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a tariff associated with Eastern Shore's firm transportation service that enables Eastern Shore to forgo scheduling service for up to 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, 2017, in connection with our Annual Meeting to be held on or about May 3, 2017

Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the Shelf Agreement for the future purchase of our Shelf Notes

PSC: Public Service Commission, which is the state agency that regulates the rates and services of 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, a materials company that supplies electricity to FPU. Eight Flags' CHP plant is located at the Rayonier facility. Eight Flags also sells steam to Rayonier.

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

Revolver: The unsecured revolving credit facility issued to us by the Lenders

Rights Plan: A plan designed to protect against abusive or coercive takeover tactics that are contrary to the best interests of Chesapeake Utilities stockholders

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

Sanford Group: FPU and other responsible parties involved with the Sanford environmental 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

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

Shelf Notes: Unsecured senior promissory notes that we may request Prudential to purchase under the Shelf Agreement

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 companies leading companies

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

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

Xeron: Xeron, Inc., Chesapeake Utilities' wholly-owned propane and crude oil wholesale marketing subsidiary, based in Houston, Texas

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. 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 timing of certification authorizations associated with new capital projects;
- 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;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- the timing and extent of changes in commodity prices and interest rates;
- the ability to establish and maintain new key supply sources;
- the effect of spot, forward and future market prices on our various energy businesses;
- the effect of competition on our businesses;
- the capital-intensive nature of our regulated 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 ability to construct facilities at or below estimated costs;
- the creditworthiness of counterparties with which we are engaged in transactions;
- 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;
- risks related to cyber-attacks or cyber-terrorism that could disrupt our business operations or result in failure of information technology systems; and
- the impact of significant changes to current tax regulations and rates.

ITEM 1. BUSINESS.

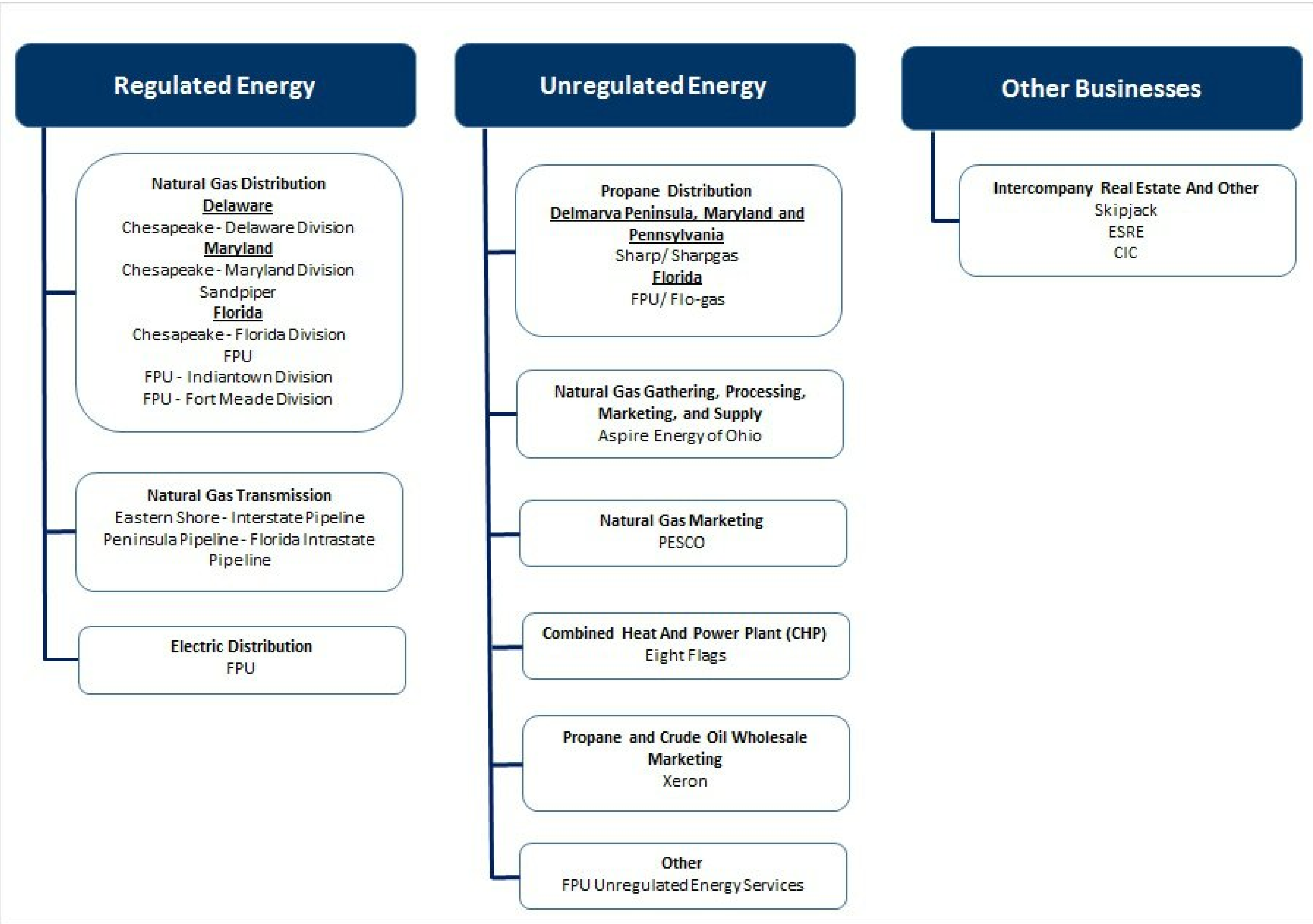
CORPORATE OVERVIEW

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; propane and crude oil wholesale marketing; 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:



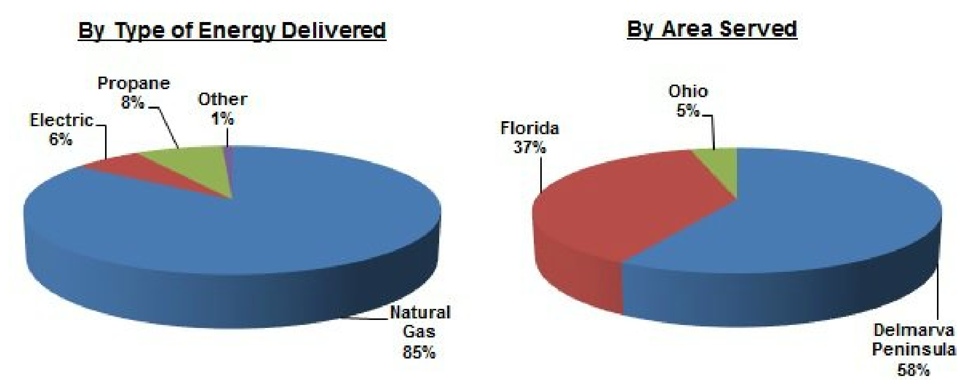
The following table shows operating income for the year ended December 31, 2016, and total assets as of December 31, 2016, for our operating segments and other businesses and eliminations:

(dollars in thousands)	Operating Income	Total Assets
Regulated Energy	$ 69,851	$ 986,752
Unregulated Energy	13,844	226,368
Other businesses and eliminations	401	16,099
Total	$ 84,096	$ 1,229,219

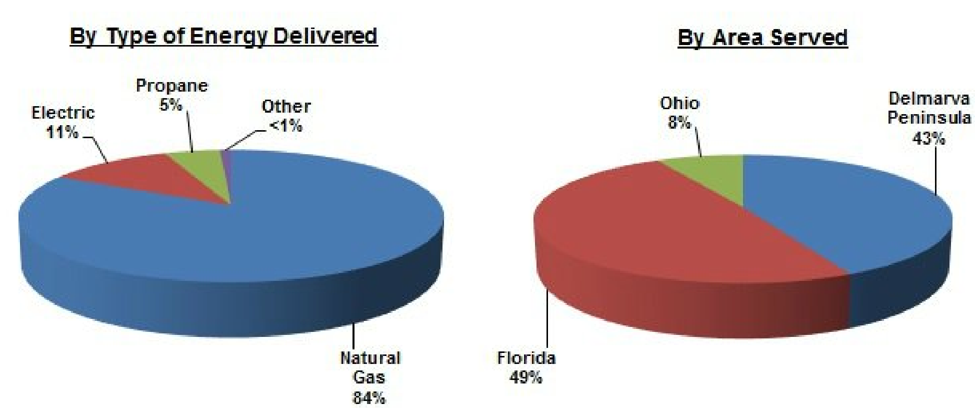
Additional financial information by business segment is set forth in *Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation,* and *Item 8, Financial Statements and Supplementary Data* (see Note 5, *Segment Information,* in the consolidated financial statements).

The following charts present operating income by type of energy delivered and areas served for the year ended December 31, 2016 and average investment by type of energy delivered and areas served as of December 31, 2016.

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, 2016.

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 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, 2016:

	Delmarva Natural Gas Distribution(2)		Florida Natural Gas Distribution (3)		FPU Electric Distribution	
Operating Revenues *(in thousands)*						
Residential	$ 49,841	57%	$ 33,329	35%	$ 46,459	55 %
Commercial	27,274	32%	33,740	35%	41,704	50 %
Industrial	7,420	9%	27,057	28%	3,497	4 %
Other (1)	1,409	2%	1,438	2%	(7,505)	(9)%
Total Operating revenues	$ 85,944	100%	$ 95,564	100%	$ 84,155	100 %
Volumes *(in Dts for natural gas/MWHs for electric)*						
Residential	3,227,594	27%	1,651,870	7%	303,654	47 %
Commercial	3,407,184	29%	8,194,310	33%	304,458	47 %
Industrial	5,032,872	43%	15,296,206	60%	29,700	5 %
Other	92,807	1%	—	—%	8,484	1 %
Total Volumes	11,760,457	100%	25,142,386	100%	646,296	100 %
Average Number of Customers (4)						
Residential	66,175	91%	68,640	91%	24,289	77 %
Commercial	6,746	9%	5,629	7%	7,404	23 %
Industrial	125	—%	1,859	2%	2	— %
Other	5	—%	—	—%	—	— %
Total Average Customers	73,051	100%	76,128	100%	31,695	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) Delmarva natural gas distribution includes Chesapeake Utilities' Delaware and Maryland divisions in addition to Sandpiper.
(3) Florida natural gas distribution includes Chesapeake Utilities' Florida division, FPU and FPU's Indiantown and Fort Meade divisions.
(4) Average number of customers is based on twelve-month average for the year ended December 31, 2016.

The following table presents operating revenues and design day capacity for Eastern Shore for the year ended December 31, 2016 and contracted firm transportation capacity at December 31, 2016:

		Eastern Shore	
Operating Revenues *(in thousands)*			
Local distribution companies - affiliated [1]	$	15,476	29%
Local distribution companies - non-affiliated		20,826	39%
Commercial and industrial		16,521	31%
Other [2]		83	1%
Total Operating Revenues	$	52,906	100%
Contracted firm transportation capacity *(in Dts/d)*			
Local distribution companies - affiliated		102,902	43%
Local distribution companies - non-affiliated		66,182	28%
Commercial and industrial		67,923	29%
Total		237,007	100%
Design day capacity *(in Dts/d)*		237,007	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.

Peninsula Pipeline contracts with both affiliated and non-affiliated customers to provide firm transportation service. For the year ended December 31, 2016, operating revenues of Peninsula Pipeline were $6.8 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; however, FPU includes this amount in its purchased fuel cost and recovers it through the fuel cost recovery mechanism.

As of December 31, 2016, our investments in our regulated operations were as follows: $126.1 million for Delmarva natural gas distribution; $290.4 million for Florida natural gas and electric distribution; and $186.5 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’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. In 2016, Sandpiper received approval from the Maryland PSC to include in its rates a weather normalization adjustment for residential heating and smaller commercial heating customers. See *Item 8, Financial Statements and Supplementary Data* (Note 18, *Rates and Other Regulatory Activities*, in the consolidated financial statements) for more information.

We do not currently have any weather 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	7/14/2009	12/17/2008	4/28/2014	5/1/2006	12/30/2010 [(2)]	12/2/2015
Effective date of permanent rates	01/01/2017	1/14/2010	1/14/2010[(1)]	11/1/2014	12/1/2007	7/29/2011 [(2)]	12/1/2016
Rate increase approved	$2,250,000	$2,536,300	$7,969,000	$3,750,000	$648,000	$805,000 [(2)]	$—
Rate of return approved	9.75% [(3)]	10.80%[(3)]	10.85%[(3)]	10.25%[(3), (4)]	10.75%[(3)]	13.90% [(2),(5)]	Not Stated [(6)]

(1) The effective date of the order approving the settlement agreement, which adjusted the rates originally approved on June 4, 2009.
(2) We filed base rate proceedings for Eastern Shore on January 27, 2017. See *Item 8, Financial Statements and Supplementary Data* (Note 18, *Rates and Other Regulatory Activities*, in the consolidated financial statements) for more information.
(3) Allowed after-tax return on equity.
(4) The terms of the settlement agreement for the FPU electric division rate case 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 was not allowed to file for a base rate increase prior to December 2016, unless its allowed return on equity fell below the authorized range. If the allowed return on equity exceeded the authorized range, the Office of the Public Counsel could seek a rate decrease.
(5) Allowed pre-tax, pre-interest rate of return.
(6) 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.

In addition to the base rates approved by the PSCs, certain of our local distribution utilities have additional surcharge mechanisms which 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.

In February, 2017, FPU's electric division filed a petition with the Florida PSC, requesting a temporary surcharge mechanism to recover costs, inclusive of an appropriate return on investment, associated with an essential reliability and modernization project on its electric distribution system. We are seeking approval to invest approximately $59.8 million, over a five-year period associated with this project. In February, 2017, the Office of Public Counsel intervened in this petition. The outcome of our petition is not known at this time.

See *Item 8, Financial Statements and Supplementary Data* (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 other sources of energy. 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

Our Delaware and Maryland divisions use their firm transportation resources, summarized in the table below, 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.

Division	Counterparty	Maximum Daily Firm Transportation Capacity (Dts)	Contract Expiration Date
Delaware	Eastern Shore	73,779	2017 - 2028
	Columbia Gas	10,960	2017 - 2020
	Transco	21,423	2017 - 2028
	TETLP	34,100	2027
Maryland	Eastern Shore	26,673	2017 - 2027
	Columbia Gas	4,200	2017 - 2019
	Transco	6,188	2017 - 2019
	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 an unaffiliated energy marketing and risk management company through an asset management agreement to optimize their transportation and storage capacity and secure an adequate supply of natural gas. Pursuant to the asset management agreement, the asset manager pays our divisions a fee, which our divisions share with their customers. The current asset management agreement expires in March 2017. Our Delaware and Maryland divisions are currently negotiating an asset management agreement with PESCO and anticipate executing a three-year agreement by the end of the first quarter of 2017. The Delaware PSC has approved PESCO serving as Asset Manager.

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 3.4 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 2,450 Dts of maximum daily firm transportation capacity available from Eastern Shore through contracts expiring on various dates between 2017 and 2027.

Our Florida division has a firm transportation service agreement with Gulfstream for firm transportation capacity of 10,000 Dts/d until May 2022. Pursuant to a program approved by the Florida PSC, the capacity under this agreement has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, we are contingently liable to Gulfstream if any party that acquired the capacity through release fails to pay the capacity charge.

FPU has firm transportation service agreements with FGT, Florida City Gas and Peninsula Pipeline, ranging from 56,455 to 97,277 Dts/d. These agreements expire on various dates between 2017 and 2035. 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.

FPU currently purchases its wholesale electricity primarily from two suppliers, JEA and Gulf Power, under full requirements contracts expiring in December 2017 and 2019, respectively. The JEA contract provides generation and transmission service to northeast Florida. The Gulf Power contract provides generation and transmission service to northwest Florida. FPU has a renewable energy purchase agreement with Rayonier to purchase between 1.7 MWH and 3.0 MWH of electricity annually through 2036. FPU also has an agreement to purchase up to 20 MWH of electricity from its affiliate, Eight Flags. The electricity purchased from Rayonier and Eight Flags 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) propane and crude oil wholesale marketing; (iii) natural gas marketing; (iv) unregulated natural gas supply, gathering and processing; (v) electricity and steam generation; and (vi) 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 primarily to residential, commercial/industrial and wholesale customers in Delaware, Maryland, Virginia 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 the customers once a month.

Propane Distribution - Operational Highlights

For the year ended December 31, 2016, 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	$ 19,309	34%	$ 5,427	31%
Residential metered	6,347	11%	4,602	27%
Commercial bulk	11,679	20%	4,354	25%
Commercial metered	—	—%	1,913	11%
Wholesale	15,914	28%	736	4%
Other [(1)]	4,186	7%	361	2%
Total Operating Revenues	$ 57,435	100%	$ 17,393	100%
Volumes ***(in thousands of gallons)***				
Residential bulk	8,940	20%	1,331	22%
Residential metered	3,222	6%	927	15%
Commercial bulk	9,432	21%	2,311	37%
Commercial metered	—	—%	824	13%
Wholesale	20,834	46%	818	13%
Other	3,351	7%	—	—%
Total Volumes	45,779	100%	6,211	100%
Average Number of Customers [(2)]				
Residential bulk	26,007	67%	8,918	55%
Residential metered	8,421	22%	6,175	38%
Commercial bulk	4,153	11%	920	6%
Commercial metered	38	—%	274	1%
Wholesale	35	—%	6	—%
Total Average Customers	38,654	100%	16,293	100%

(1) Operating revenues from "Other" sources include revenues from customer loyalty programs; delivery, service and appliance fees; and unbilled revenues.
(2)Average number of customer is based on twelve-month average for the year ended December 31, 2016.

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 distributed 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 6.2 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

Xeron trades in short-term natural gas liquids and crude oil forward and futures contracts on the InterContinentalExchange, Inc. Xeron settles its purchases and sales financially, without taking physical delivery of the propane or crude oil. The level and profitability of the propane and crude oil wholesale trading activity are affected by both propane and crude oil wholesale price volatility and liquidity in the wholesale market. At December 31, 2016, Xeron did not have any open futures or forward contracts.

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 Florida, on the Delmarva Peninsula, and in Ohio. In 2016, PESCO had operating revenues of $58.0 million in Florida, $15.7 million from customers located on the Delmarva Peninsula, $9.8 million from customers located in Ohio, and $11.9 million from customers located in other states. 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. PESCO is currently negotiating an asset management agreement with our Delaware and Maryland divisions and anticipates executing a three-year agreement by the end of the first quarter of 2017.

In January 2016, PESCO entered into a SCO 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 SCO supplier agreement, which terminates on March 31, 2017.

In conjunction with the SCO 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. The contracts expire in March 31, 2017. We initially 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 de-designated the hedges as they were no longer deemed to be highly effective. We are now accounting for them as derivatives on a mark-to-market basis, with the change in fair value reflected as unrealized gain (loss) in current period earnings, and these are no longer offset by any associated gain (loss) in the value of the inventory previously hedged.

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-months period ended December 31, 2016, Aspire Energy's operating revenues and deliveries by customer type were as follows:

	Operating revenues		Deliveries
	(in thousands)		*(in Dts)*
Supply to Columbia Gas of Ohio	$	9,429	2,197
Supply to CGC		8,037	1,238
Supply to Marketers - affiliated		3,544	1,604
Supply to Marketers - unaffiliated		3,230	1,266
Other (including natural gas gathering and processing)		2,313	1,797
Total	$	26,553	8,102

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 20 MWH of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of residual steam. 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, it also started selling steam to Rayonier pursuant to a separate 20-year contract. The CHP plant is powered by natural gas transported by FPU through its distribution system. During the second half of 2016, Eight Flags generated $7.0 million in operating revenues from the sale of electricity to FPU and $1.3 million from the sale of steam to Rayonier.

Other Unregulated Energy-Related Businesses

FPU sells energy-related merchandise in Florida. Operating revenues in 2016 from these other unregulated businesses totaled $2.8 million.

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.

Prior to September 30, 2014, our business included a third segment, "Other," which consisted primarily of BravePoint, our former advanced information services subsidiary.

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, 2016, we had a total of 903 employees, 117 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	58	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	50	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	47	Senior Vice President of Strategic Development (May 2013 - present) Chief Operating Officer - Sharp, Aspire Energy, PESCO and Xeron (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	56	Senior Vice President (September 2004 - present) President, Eastern Shore (January 1997 - 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	59	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	59	Senior Vice President (Effective February 2017) 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 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 May 12, 2016 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 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 not satisfied by the cash flows 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 energy marketing subsidiaries are exposed to market risks beyond our control, which could adversely affect our financial results and capital requirements.

Our energy marketing subsidiaries are subject to market risks beyond our control, including market liquidity and commodity price volatility. Although we maintain risk management policies, 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 and/or propane prices, and (ii) daily price movements between the time natural gas and/or propane 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 and/or propane 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 energy marketing subsidiaries are exposed to credit risk of their counterparties.

Our energy marketing subsidiaries extend credit to counterparties and continually monitor and manage collections aggressively. Each of these subsidiaries is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform, and any underlying collateral is inadequate, we could experience financial losses, which would negatively impact our results of operations.

Our energy marketing subsidiaries are dependent upon the availability of credit to successfully operate their businesses.

Our energy marketing subsidiaries are dependent upon the availability of credit to buy propane and natural gas for resale or to trade. If financial market conditions decline generally, or the financial condition of these subsidiaries or of our Company declines, then the cost of credit available to these subsidiaries 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.

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 marketing operations compete with third-party suppliers to sell natural gas to commercial and industrial customers. 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. 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.

Our propane and crude oil wholesale marketing operation competes with various marketers, many of which have significantly greater resources and are able to obtain price or volumetric advantages. Failure to effectively compete with these marketers 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 and retain talented professionals and 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 the 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 regulated energy, unregulated propane distribution and our other unregulated natural gas services 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 relies primarily on two suppliers, Gulf Power for the northwest service territory and

JEA for the northeast service territory. Any continued interruption of service on these systems 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, wholesale marketing 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 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 6.2 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 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 with the increased federal oversight that may result from such proposals. If such 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, 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. 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 believe 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 Rights Plan, certificate of incorporation and bylaws may delay or prevent a transaction that stockholders would view as favorable.

Our Rights Plan, 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.

Key Properties

We own approximately 1,459 miles of natural gas distribution mains (together with related service lines, meters and regulators) located in New Castle, Kent and Sussex Counties, Delaware; and Cecil, Caroline, Dorchester, Wicomico and Worcester Counties, Maryland. We own approximately 2,841 miles of natural gas distribution mains (and related equipment) in Nassau, Polk, Osceola, Citrus, DeSoto, Liberty, Hillsborough, Holmes, Jackson, Gadsden, Gilchrist, Union, Washington, Pasco, Suwannee, Palm Beach, Broward, Martin, Marion, Seminole and Volusia 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 448 miles of natural gas transmission pipeline, extending from supply interconnects at Parkesburg, Daleville and Honey Brook, 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 Suwannee, Indian River, Palm Beach and Polk 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 890 miles of electric distribution line in Jackson, Liberty, Calhoun and Nassau Counties, Florida.

We own approximately 343 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 5.2 million gallons, in Delaware, Maryland, Pennsylvania and Virginia, located on real estate that is either owned or leased by us. In Florida, we own bulk propane storage facilities with an aggregate capacity of approximately 1.0 million gallons. Xeron does not own physical storage facilities or equipment to transport propane.

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, Worcester, Wicomico, Dorchester, Talbot, Cecil and Somerset Counties, Maryland; New Castle, Kent and Sussex Counties, Delaware; Accomack County, Virginia; Palm Beach, Volusia, Levy, Martin, Jackson, Broward, Nassau, Brevard, Alachua, Hendry, Okeechobee, and Polk Counties, Florida; and Orrville, Ohio.

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: Palm Beach, Volusia, Levy, Martin, Jackson, Broward, Nassau, Brevard, Alachua, Hendry and Okeechobee Counties, Florida. The FPU assets subject to the lien also include: 1,924 miles of natural gas distribution mains (and related equipment) in its service areas; 20 miles of electric transmission line located in Nassau County, Florida; 890 miles of electric distribution line located in Jackson, Liberty, Calhoun and Nassau Counties in Florida; propane storage facilities with a total capacity of 1.0 million gallons, located in south and central Florida; and 59 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, 2017, there were 2,381 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 2016 and 2015 are included in the below table.

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
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**
2015					
	March 31	$ 52.22	$ 44.83	$ 50.61	$ 0.2700
	June 30	$ 55.72	$ 44.37	$ 53.85	$ 0.2875
	September 30	$ 56.15	$ 45.25	$ 53.08	$ 0.2875
	December 31	$ 61.13	$ 49.50	$ 56.75	$ 0.2875

We have paid a cash dividend to our common stock stockholders for 56 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 2016 and 2015, totaling $1.2025 per share and $1.1325 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, 2016.

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, 2016 through October 31, 2016 [1]	418	$ 58.33	—	—
November 1, 2016 through November 30, 2016	—	—	—	—
December 1, 2016 through December 31, 2016	—	—	—	—
Total	418	$ 58.33	—	—

(1) In October 2016, 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, 418 shares were purchased through the reinvestment of dividends.

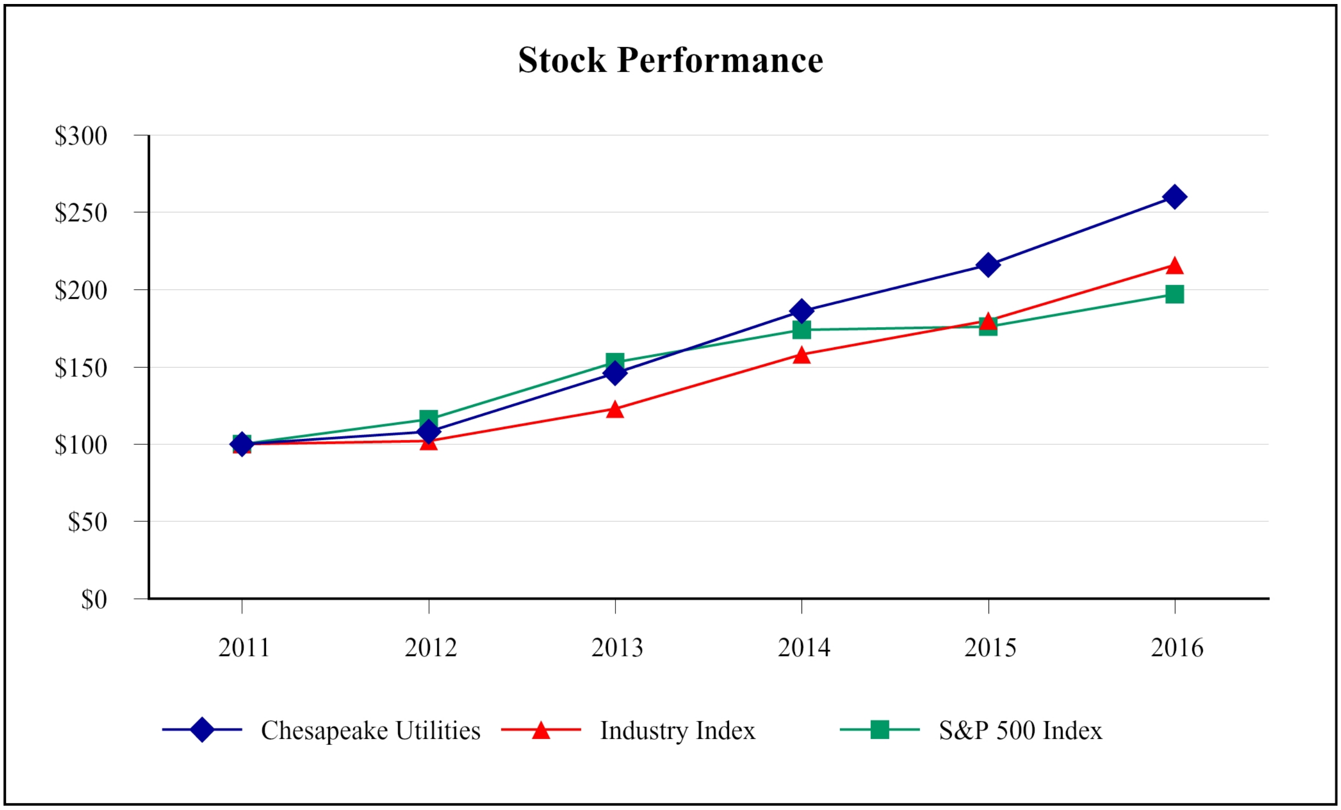
(2) Except for the purpose described in footnote [1], we have no publicly announced plans or programs to repurchase our shares.

Discussion of our compensation plans, for which shares of our common stock are authorized for issuance, is included 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, 2016, 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, Delta Natural Gas Company, Inc., Spire, Inc., New Jersey Resources Corporation, Northwest Natural Gas Company, RGC Resources, Inc., South Jersey Industries, Inc., and WGL Holdings, Inc.

The comparison assumes $100 was invested on December 31, 2011 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.



	2011	2012	2013	2014	2015	2016
Chesapeake Utilities	$ 100	$ 108	$ 146	$ 186	$ 216	$ 260
Industry Index	$ 100	$ 102	$ 123	$ 158	$ 180	$ 216
S&P 500 Index	$ 100	$ 116	$ 153	$ 174	$ 176	$ 197

ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,		
	2016	**2015**	**2014**
Operating [1]			
(in thousands)			
Revenues			
Regulated Energy	**$ 305,689**	$ 301,902	$ 300,442
Unregulated Energy	**203,778**	162,108	184,961
Other businesses and eliminations	**(10,607)**	(4,766)	13,431
Total revenues	**$ 498,860**	$ 459,244	$ 498,834
Operating income			
Regulated Energy	**$ 69,851**	$ 60,985	$ 50,451
Unregulated Energy	**13,844**	16,355	11,723
Other businesses and eliminations	**401**	418	105
Total operating income	**$ 84,096**	$ 77,758	$ 62,279
Net income from continuing operations	**$ 44,675**	$ 41,140	$ 36,092
Assets			
(in thousands)			
Gross property, plant and equipment	**$ 1,175,595**	1,007,489	$ 870,125
Net property, plant and equipment	**$ 986,664**	$ 854,950	$ 689,762
Total assets	**$ 1,229,219**	$ 1,067,421	$ 904,469
Capital expenditures [1]	**$ 169,376**	$ 142,713	$ 98,057
Capitalization			
(in thousands)			
Stockholders' equity	**$ 446,086**	$ 358,138	$ 300,322
Long-term debt, net of current maturities	**136,954**	149,006	158,486
Total capitalization	**$ 583,040**	$ 507,144	$ 458,808
Current portion of long-term debt	**12,099**	9,151	9,109
Short-term debt	**209,871**	173,397	88,231
Total capitalization and short-term financing	**$ 805,010**	$ 689,692	$ 556,148

(1) These amounts exclude the results of distributed energy due to their reclassification to discontinued operations. We closed our distributed energy operation in 2007. These amounts also include accruals for capital expenditures that we have incurred for each reporting period.

(2) These amounts include the financial position and results of operation of FPU for the period from the merger (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,						
2013	2012	2011	2010	2009[(2)]	2008	2007
$ 264,637	$ 246,208	$ 256,226	$ 269,438	$ 138,671	$ 116,123	$ 128,566
166,723	133,049	149,586	146,793	119,973	161,290	115,190
12,946	13,245	12,215	11,315	10,141	14,030	14,530
$ 444,306	$ 392,502	$ 418,027	$ 427,546	$ 268,785	$ 291,443	$ 258,286
$ 50,084	$ 46,999	$ 43,911	$ 43,267	$ 26,668	$ 23,833	$ 21,739
12,353	8,355	9,619	8,150	8,390	3,600	5,244
297	1,281	175	513	(1,322)	1,046	1,131
$ 62,734	$ 56,635	$ 53,705	$ 51,930	$ 33,736	$ 28,479	$ 28,114
$ 32,787	$ 28,863	$ 27,622	$ 26,056	$ 15,897	$ 13,607	$ 13,218
$ 805,394	$ 697,159	$ 625,488	$ 584,385	$ 543,905	$ 381,689	$ 352,838
$ 631,246	$ 541,781	$ 487,704	$ 462,757	$ 436,587	$ 280,671	$ 260,423
$ 837,522	$ 733,746	$ 709,066	$ 670,993	$ 615,811	$ 385,795	$ 381,557
$ 108,039	$ 78,210	$ 44,431	$ 46,955	$ 26,294	$ 30,844	$ 30,142
$ 278,773	$ 256,598	$ 240,780	$ 226,239	$ 209,781	$ 123,073	$ 119,576
117,592	101,907	110,285	89,642	98,814	86,422	63,256
$ 396,365	$ 358,505	$ 351,065	$ 315,881	$ 308,595	$ 209,495	$ 182,832
11,353	8,196	8,196	9,216	35,299	6,656	7,656
105,666	61,199	34,707	63,958	30,023	33,000	45,664
$ 513,384	$ 427,900	$ 393,968	$ 389,055	$ 373,917	$ 249,151	$ 236,152

	For the Year Ended December 31,		
	2016	**2015**	**2014**
Common Stock Data and Ratios			
Basic earnings per share from continuing operations [(1) (3)]	**$ 2.87**	$ 2.73	$ 2.48
Diluted earnings per share from continuing operations [(1) (3)]	**$ 2.86**	$ 2.72	$ 2.47
Diluted earnings per share growth - 1 year	**5.1%**	10.1%	9.3%
Diluted earnings per share growth - 5 year	**8.4%**	8.4%	11.6%
Diluted earnings per share growth - 10 year	**9.3%**	8.4%	8.5%
Return on average equity from continuing operations [(1)]	**11.3%**	12.1%	12.2%
Common equity / total capitalization	**76.5%**	70.6%	65.5%
Common equity / total capitalization and short-term financing	**55.4%**	51.9%	54.0%
Capital expenditures / average total capitalization	**31.1%**	29.5%	22.9%
Book value per share [(3)]	**$ 27.36**	$ 23.45	$ 20.59
Market price:			
High	**$ 70.000**	$ 61.130	$ 52.660
Low	**$ 52.250**	$ 44.370	$ 37.493
Close	**$ 66.950**	$ 56.750	$ 49.660
Weighted average number of shares outstanding [(3)]	**15,570,539**	15,094,423	14,551,308
Shares outstanding at year-end [(3)]	**16,303,499**	15,270,659	14,588,711
Registered common shareholders	**2,373**	2,396	2,329
Cash dividends declared per share [(3)]	**$ 1.20**	$ 1.13	$ 1.07
Dividend yield (annualized) [(4)]	**1.8%**	2.0%	2.2%
Book yield	**4.7%**	5.1%	5.4%
Payout ratio from continuing operations [(1) (5)]	**41.8%**	41.5%	43.0%
Additional Data			
Customers			
Natural gas distribution	**149,179**	144,872	141,227
Electric distribution	**31,695**	31,430	31,272
Propane distribution	**54,947**	53,682	53,272
Total employees	**903**	832	753

(1) These amounts exclude the results of a former distributed energy subsidiary due to its reclassification to discontinued operations in 2007.

(2) 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.

(3) 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.

(4) 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.

(5) 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,

2013	2012	2011	2010	2009[2]	2008	2007
$ 2.27	$ 2.01	$ 1.93	$ 1.83	$ 1.45	$ 1.33	$ 1.31
$ 2.26	$ 1.99	$ 1.91	$ 1.82	$ 1.43	$ 1.32	$ 1.29
13.6%	4.2%	4.9%	27.3%	8.3%	2.3%	10.3%
11.4%	9.1%	10.3%	8.5%	5.6%	2.4%	7.2%
6.8%	8.1%	7.8%	6.7%	3.0%	6.7%	5.3%
12.2%	11.6%	11.6%	11.6%	11.2%	11.2%	11.5%
70.3%	71.6%	68.6%	71.6%	68.0%	58.7%	65.4%
54.3%	60.0%	61.1%	58.2%	56.1%	49.4%	50.6%
28.6%	22.0%	13.3%	15.0%	10.2%	15.7%	16.5%
$ 19.28	$ 17.82	$ 16.78	$ 15.84	$ 14.89	$ 12.02	$ 11.76
$ 40.780	$ 32.613	$ 29.687	$ 28.133	$ 23.333	$ 23.227	$ 24.833
$ 30.560	$ 26.593	$ 24.000	$ 18.673	$ 14.680	$ 14.620	$ 18.667
$ 40.013	$ 30.267	$ 28.900	$ 27.680	$ 21.367	$ 20.987	$ 21.233
14,430,962	14,379,216	14,333,699	14,211,831	10,969,980	10,217,772	10,114,562
14,457,345	14,396,248	14,350,959	14,286,293	14,091,471	10,240,682	10,166,115
2,345	2,396	2,481	2,482	2,670	1,914	1,920
$ 1.01	$ 0.96	$ 0.91	$ 0.87	$ 0.83	$ 0.81	$ 0.78
2.6%	3.2%	3.2%	3.2%	3.9%	3.9%	3.7%
5.4%	5.5%	5.6%	5.7%	6.2%	6.8%	6.8%
44.6%	47.8%	47.4%	47.6%	57.6%	60.5%	60.2%
138,210	124,015	121,934	120,230	117,887	65,201	62,884
31,151	31,066	30,986	30,966	31,030	—	—
51,988	49,312	48,824	48,100	48,680	34,981	34,143
842	738	711	734	757	448	445

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 structure for non-regulated segments. 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 territories;
- 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 has 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,	2016	2015	Increase (decrease)	2015	2014	Increase (decrease)
Operating Income:						
Regulated Energy	**$ 69,851**	$ 60,985	$ 8,866	$ 60,985	$ 50,451	$ 10,534
Unregulated Energy	**13,844**	16,355	(2,511)	16,355	11,723	4,632
Other businesses and eliminations	**401**	418	(17)	418	105	313
Total Operating Income	**84,096**	77,758	6,338	77,758	62,279	15,479
Gains from sales of businesses	**—**	—	—	—	7,139	(7,139)
Other income (expense)	**(441)**	293	(734)	293	101	192
Interest charges	**10,639**	10,006	633	10,006	9,482	524
Income Before Income Taxes	**73,016**	68,045	4,971	68,045	60,037	8,008
Income taxes	**28,341**	26,905	1,436	26,905	23,945	2,960
Net Income	**$ 44,675**	$ 41,140	$ 3,535	$ 41,140	$ 36,092	$ 5,048
Earnings Per Share of Common Stock:						
Basic	**$ 2.87**	$ 2.73	$ 0.14	$ 2.73	2.48	$ 0.25
Diluted	**$ 2.86**	$ 2.72	$ 0.14	$ 2.72	2.47	$ 0.25

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
Natural gas marketing	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)
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
Impact of common stock issuance	—	—	(0.05)
Interest charges	(633)	(387)	(0.03)
Change in other income (expense)	(734)	(449)	(0.03)
Tax rate changes	—	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.**

2015 compared to 2014

Our net income increased by approximately $5.0 million, or $0.25 per share (diluted) in 2015, compared to 2014. Key variances included:

(in thousands, except per share amounts)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2014 Reported Results	$ 60,037	$ 36,092	$ 2.47
Adjusting for unusual items:			
Gains on sales of businesses, recorded in 2014	(7,139)	(4,292)	(0.29)
Asset impairment charges, recorded in 2014	6,880	4,136	0.28
Weather impact	(4,408)	(2,650)	(0.18)
Gain from settlement agreement associated with customer billing system	1,500	902	0.06
	(3,167)	(1,904)	(0.13)
Increased (Decreased) Gross Margins:			
Higher retail propane margins	8,930	5,369	0.37
Service expansions*	5,215	3,135	0.21
Other natural gas growth	4,260	2,561	0.17
GRIP*	4,151	2,496	0.17
FPU electric base rate increase	2,465	1,482	0.10
Xeron trading losses	(1,179)	(709)	(0.05)
Decreased wholesale propane sales	(446)	(268)	(0.02)
	23,396	14,066	0.95
Increased Other Operating Expenses:			
Higher staffing and associated costs	(4,071)	(2,447)	(0.17)
Higher depreciation, asset removal and property tax costs due to new capital investments	(3,265)	(1,963)	(0.13)
Higher facility maintenance and service contractor costs	(2,499)	(1,502)	(0.10)
Costs associated with a customer billing system settlement and other transactions	(1,081)	(650)	(0.04)
Increased incentive compensation	(910)	(547)	(0.04)
	(11,826)	(7,109)	(0.48)
Net contribution from Aspire Energy, including impact of shares issued	567	341	(0.06)
Adjustment for other shares issued in 2015	—	—	(0.01)
Interest charges	(525)	(316)	(0.02)
Net other changes	(437)	(259)	(0.02)
Tax rate change	—	229	0.02
Year ended December 31, 2015 Reported Results	$ 68,045	$ 41,140	$ 2.72

*** 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 completed since 2014 and our major projects and initiatives currently underway. 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	
	2016	2015	Variance	2015	2014	Variance	2017	2018
Existing Major Projects and Initiatives								
Capital Investment Projects	$ 43,717	$ 21,536	$ 22,181	$ 21,536	$ 5,846	$ 15,690	$ 48,185	$ 47,107
Regulatory Proceedings	1,487	—	1,487	—	—	—	2,250	2,250
Total Existing Major Projects and Initiatives	$ 45,204	$ 21,536	$ 23,668	$ 21,536	$ 5,846	$ 15,690	$ 50,435	$ 49,357
Future Major Projects and Initiatives								
Capital Investment Projects [1]	$ —	$ —	$ —	$ —	$ —	$ —	$ 2,250	$ 20,238
Regulatory Proceedings [2], [3]	—	—	—	—	—	—	—	—
Total Future Major Projects and Initiatives	$ —	$ —	$ —	$ —	$ —	$ —	$ 2,250	$ 20,238
Total	$ 45,204	$ 21,536	$ 23,668	$ 21,536	$ 5,846	$ 15,690	$ 52,685	$ 69,595

(1) This represents gross margin for the System Reliability and 2017 Expansion projects.

(2) In January 2017, Eastern Shore filed a rate case with the FERC. The outcome of the rate case is not known at this time. See Item 8, *Financial Statements and Supplementary Data*, Note 18, *Rates and Other Regulatory Activities,* for additional information.

(3) In February 2017, FPU's electric division filed a petition with the Florida PSC requesting a temporary surcharge mechanism to recover the costs, inclusive of an appropriate return on investment, associated with essential reliability and modernization projects on its electric distribution system. See Item 8, *Financial Statements and Supplementary Data*, Note 18, *Rates and Other Regulatory Activities,* for additional information.

Major Projects and Initiatives Completed Since 2014

The following table summarizes gross margin generated by our major projects and initiatives completed since 2014 (dollars in thousands):

	Gross Margin for the Period							
	Year Ended December 31,			Year Ended December 31,			Estimate for	
	2016	2015	Variance	2015	2014	Variance	2017	2018
Capital Investment Projects:								
Acquisition:								
Aspire Energy	$ 12,271	$ 6,324	$ 5,947	$ 6,324	$ —	$ 6,324	$ 13,376	$ 14,302
Service Expansions:								
Short-term contracts								
Delaware	$ 11,454	$ 4,952	$ 6,502	$ 4,952	$ 2,026	$ 2,926	$ 4,339	$ 714
Total short-term contracts	$ 11,454	$ 4,952	$ 6,502	$ 4,952	$ 2,026	$ 2,926	$ 4,339	$ 714
Long-term Contracts								
Delaware	$ 1,815	$ 1,844	$ (29)	$ 1,844	$ 463	$ 1,381	$ 6,965	$ 7,605
Florida	1,627	908	719	908	—	908	1,622	1,622
Total long-term contracts	$ 3,442	$ 2,752	$ 690	$ 2,752	$ 463	$ 2,289	$ 8,587	$ 9,227
Total Service Expansions	$ 14,896	$ 7,704	$ 7,192	$ 7,704	$ 2,489	$ 5,215	$ 12,926	$ 9,941
Florida GRIP	$ 11,552	$ 7,508	$ 4,044	$ 7,508	$ 3,357	$ 4,151	$ 13,727	$ 14,407
Eight Flags' CHP Plant	$ 4,998	$ —	$ 4,998	$ —	$ —	$ —	$ 8,156	$ 8,457
Total Capital Investment Projects	$ 43,717	$ 21,536	$ 22,181	$ 21,536	$ 5,846	$ 15,690	$ 48,185	$ 47,107
Existing Regulatory Proceedings:								
Delaware Division Rate Case	$ 1,487	$ —	$ 1,487	$ —	$ —	$ —	$ 2,250	$ 2,250
Total Existing Regulatory Proceedings	$ 1,487	$ —	$ 1,487	$ —	$ —	$ —	$ 2,250	$ 2,250
Total Existing Major Projects and Initiatives	$ 45,204	$ 21,536	$ 23,668	$ 21,536	$ 5,846	$ 15,690	$ 50,435	$ 49,357

Aspire Energy
Aspire Energy generated $5.9 million in additional gross margin for 2016 compared to 2015 due in part to the fact that 2015 included only nine months of results commencing on April 1, 2015, the date we acquired this business. Of the $5.9 million of 2016 gross margin, $4.2 million of gross margin was generated in the first quarter of 2016. Aspire Energy also generated higher gross margin in 2016 as a result of pricing amendments to long-term gas sales agreements, additional management fees and higher volumes of natural gas delivered to or on behalf of certain of its customers.

Service Expansions
In January 2015, the Florida PSC approved a firm transportation agreement between Peninsula Pipeline and our Florida natural gas distribution division. Pursuant to this agreement, Peninsula Pipeline provides natural gas transmission service to support our expansion of natural gas distribution service in Polk County, Florida. Peninsula Pipeline began the initial phase of its service to Chesapeake Utilities' Florida natural gas distribution division in March 2015. This new service generated $719,000 of additional gross margin in 2016 compared to 2015.

In April 2015, Eastern Shore commenced interruptible service to an electric power generator in Kent County, Delaware. The interruptible service concluded in December 2015 and was replaced by a short-term OPT ≤ 90 Service, which generated additional gross margin of $5.4 million in 2016 compared to 2015. We have executed a 20-year long-term OPT 90 ≤ service agreement with this customer to be effective March 1, 2017, and have filed an agreement with FERC requesting: (i) the service to be effective March 1, 2017; and (ii) a waiver of the 30 day notice requirement in order to have it become effective March 1, 2017.

In October 2015, Eastern Shore submitted an application to the FERC to make certain meter tube and control valve replacements and related improvements at its TETLP interconnect facilities, which would enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. In December 2015, the FERC authorized Eastern Shore to proceed with this project, which was completed and placed in service in March 2016. Approximately 60 percent of the increased capacity has been subscribed on a short-term firm service basis. This service generated an additional gross margin of $1.4 million in 2016 compared to 2015. The remaining capacity is available for firm or interruptible service.

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 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 inception of the program in August 2012, we have invested $102.8 million, to replace 214 miles of qualifying distribution mains, $26.0 million of which was invested during 2016. The increased investment in GRIP generated additional gross margin of $4.0 million in 2016, compared to 2015.

Eight Flags' CHP Plant
In June 2016, Eight Flags completed construction of a CHP plant on Amelia Island, Florida. This CHP plant, which consists of a natural-gas-fired turbine and associated electric generator, produces approximately 20 MWH of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of residual steam. 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, it also started selling steam to Rayonier pursuant to a separate 20-year contract.

The CHP plant is powered by natural gas transported by FPU through its distribution system and Peninsula Pipeline through its intrastate pipeline. Eight Flags and other affiliates of Chesapeake Utilities generated $5.0 million in additional gross margin as a result of these new services in 2016. This amount includes gross margin of $1.4 million attributable to natural gas distribution and transportation services provided by our affiliates.

Future Major Projects and Initiatives

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 service for 45,000 Dts/d deliverable to the lateral serving the customer's facility, upon the satisfaction of certain conditions. This new service will be provided as a long-term OPT ≤ 90 Service and is expected to generate at least $5.8 million in annual gross margin. As previously discussed, during 2016 we generated $5.4 million in additional gross margin, compared to 2015, by providing short-term OPT ≤ 90 Service to this customer. In July 2016, the FERC authorized Eastern Shore to construct and operate the proposed White Oak Mainline Project, which will consist of 5.4 miles of 16-inch pipeline

looping and 3,550 horsepower of new compression in Delaware. Construction of the project is underway and long-term service is expected to commence on March 1, 2017.

System Reliability Project
In July 2016, the FERC authorized Eastern Shore to construct and operate the proposed System Reliability Project, which will consist 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 Bridgeville compressor station in Sussex County, Delaware. Construction of the project is underway and is expected to be completed in April 2017. This project was included in Eastern Shore's January 2017 base rate case filing with the FERC. The estimated annual gross margin associated with this project, assuming recovery in the 2017 rate case, is approximately $4.5 million.

2017 Expansion Project
In May 2016, Eastern Shore submitted a request to the FERC to initiate the FERC's pre-filing process for its proposed 2017 Expansion Project. The 2017 Expansion Project will provide 61,162 Dts/d of additional firm natural gas transportation service pursuant to precedent agreements Eastern Shore entered into with four existing customers as well as affiliates of Chesapeake Utilities. Facilities required to provide this new service will consist of: (i) approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; (ii) upgrades to existing metering facilities in Lancaster County, Pennsylvania; (iii) installation of an additional 3,550 horsepower compressor unit at Eastern Shore’s existing Daleville compressor station in Chester County, Pennsylvania; and (iv) approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. The project will generate approximately $15.7 million of gross margin in the first full year after the new transportation services go into effect. The estimated cost of this expansion project is $98.6 million.

Weather and Consumption
Warmer temperatures in 2016, particularly during the first quarter of the year when the demand for natural gas and propane is normally high, negatively impacted our earnings. Lower customer energy consumption, directly attributable to warmer than normal temperatures, reduced gross margin in 2016 by $3.6 million, compared to 2015. The following table summarizes the HDD and CDD information for 2016, 2015 and 2014.

HDD and CDD Information

For the Years Ended December 31,	2016	2015	Variance	2015	2014	Variance
Delmarva						
Actual HDD	**3,979**	4,363	(384)	4,363	4,826	(463)
10-Year Average HDD ("Normal")	**4,453**	4,496	(43)	4,496	4,483	13
Variance from Normal	**(474)**	(133)		(133)	343	
Florida						
Actual HDD	**672**	569	103	569	888	(319)
10-Year Average HDD ("Normal")	**828**	859	(31)	859	856	3
Variance from Normal	**(156)**	(290)		(290)	32	
Ohio						
Actual HDD	**5,818**	2,404	N/A [1]	2,404	—	N/A [1]
10-Year Average HDD ("Normal")	**6,078**	2,903	N/A [1]	2,903	—	N/A [1]
Variance from Normal	**(260)**	(499)		(499)	—	
Florida						
Actual CDD	**3,152**	3,338	(186)	3,338	2,705	633
10-Year Average CDD ("Normal")	**2,820**	2,760	60	2,760	2,768	(8)
Variance from Normal	**332**	578		578	(63)	

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

Propane Prices

Lower retail propane margins for our Delmarva 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. Margins per retail gallon returned to more normal levels, driven principally by lower propane prices and local market conditions. These market conditions, including competition with other propane suppliers as well as the availability and price of alternative energy sources, may fluctuate based on changes in demand, supply and other energy commodity prices. As expected, the level of retail margins per gallon generated during 2015 were not sustained. We continue to assume more normal levels of margins in our long-term financial plans and forecasts.

PESCO

PESCO provides natural gas supply and supply management services to residential, commercial, industrial and wholesale customers. PESCO primarily operates in Florida, on the Delmarva Peninsula, and in Ohio. 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 but sells gas that is delivered to retail or wholesale customers through affiliated and non-affiliated local distribution company systems and transmission pipelines.

In October 2016 the Delaware PSC approved PESCO as Asset Manager for our Delaware division pursuant to a three-year agreement, which goes into effect on April 1, 2017. This agreement will provide essential capacity on regional pipelines and storage to facilitate PESCO's growth strategy.

Operating revenues for PESCO were $95.4 million in 2016, compared to $56.2 million in 2015. The majority of this revenue growth was primarily attributable to increased customers and volumes in Florida, Delmarva Peninsula and in Ohio as well as the SCO supplier agreement with Columbia Gas of Ohio. The SCO supplier agreement, which terminates on March 31, 2017, provides natural gas supply for Columbia Gas of Ohio to service one of its local distribution customer pools. PESCO also assumed the obligation to store natural gas inventory to satisfy its obligations under the SCO supplier agreement.

Gross margin for 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 pays fixed storage and pipeline fees over the entire twelve-month period, although the projected volumes are expected to be highest in first quarter of 2017 followed by the fourth quarter of 2016 (contract period of April 1, 2016 - March 31, 2017).

Operating income for PESCO was $1.9 million for both 2016 and 2015. PESCO incurred a $1.0 million of increased operating expenses in 2016 due to higher costs related to additional staffing and associated costs as well as a significant loss on the SCO supplier agreement.

Xeron

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

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $1.5 million in additional gross margin for 2016, compared to 2015, due to an increase in residential, commercial and industrial customers served. The average number of residential customers on the Delmarva Peninsula increased by 3.6 percent in 2016 compared to 2015. The natural gas distribution operations in Florida generated $1.2 million in additional gross margin in 2016, compared to 2015, due primarily to an increase in commercial and industrial customers in Florida.

Regulatory Proceedings

Delaware Division rate case

In December 2016, the Delaware PSC approved a settlement agreement as recommended by the Hearing Examiner's report. The settlement agreement, among other things, provided for an increase in our Delaware division revenue requirement of $2.25 million and a rate of return on common equity of 9.75 percent. The new rates are effective for services rendered on or after January 1, 2017. Any amounts collected through interim rates in excess of $2.25 million were accrued for refund to the ratepayers beginning in the first quarter of 2017. The accrual for this refund had no material effect on our results for the year ended December 31, 2016.

Eastern Shore Rate Case
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 are based on the mainline cost of service of approximately $60 million, resulting in an overall revenue increase of approximately $18.9 million and a rate of return on common equity of 13.75 percent. The FERC issued a notice of the filing on January 31, 2017, and the comment period ended on February 8, 2017. Fourteen parties intervened in the proceeding with six of those parties filing protests. New rates are proposed to be effective on March 1, 2017. However, the FERC typically suspends the rates for a period of five months. At the end of the suspension period, Eastern Shore will file a motion to implement new rates effective August 1, 2017. Eastern Shore will respond to any comments filed.

Electric System Transformation and Reliability program
In February, 2017, FPU's electric division filed a petition with the Florida PSC, requesting a temporary surcharge mechanism to recover costs, inclusive of an appropriate return on investment, associated with an essential reliability and modernization project on its electric distribution system. We are seeking approval to invest approximately $59.8 million, over a five-year period associated with this project. In February, 2017, the Office of Public Counsel intervened in this petition. The outcome of our petition is not known at this time.

REGULATED ENERGY

For the Year Ended December 31,	2016	2015	Increase (decrease)	2015	2014	Increase (decrease)
(in thousands)						
Revenue	**$ 305,689**	$ 301,902	$ 3,787	$ 301,902	$ 300,442	$ 1,460
Cost of sales	**109,609**	122,814	(13,205)	122,814	134,560	(11,746)
Gross margin	**196,080**	179,088	16,992	179,088	165,882	13,206
Operations & maintenance	**88,098**	83,616	4,482	83,616	76,046	7,570
(Gain from a settlement)/asset impairment charge	**(130)**	(1,497)	1,367	(1,497)	6,449	(7,946)
Depreciation & amortization	**25,677**	24,195	1,482	24,195	21,915	2,280
Other taxes	**12,584**	11,789	795	11,789	11,021	768
Operating expenses	**126,229**	118,103	8,126	118,103	115,431	2,672
Operating Income	**$ 69,851**	$ 60,985	$ 8,866	$ 60,985	$ 50,451	$ 10,534

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 increase of $17.0 million, or 9.5 percent, in gross margin 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 (decrease) 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
Delaware Division Base Rate Increase	1,487
Margin from 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 ≤ 90 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. The remaining capacity is available for firm or interruptible service; 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 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 the following:

- $1.5 million from a 3.6 percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers; and
- $1.2 million from Florida natural gas 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.

Margin from 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.

<u>*Operating Expenses*</u>

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.

2015 compared to 2014

Operating income for the Regulated Energy segment increased by $2.6 million year-over-year, excluding the impact of several non-recurring items discussed below. The increase in operating income of $2.6 million was the net result of an increase in gross margin of $13.2 million, partially offset by a $10.6 million increase in operating expenses.

<u>*Gross Margin*</u>

Items contributing to the year-over-year increase of $13.2 million, or 8.0 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the year ended December 31, 2014	$ 165,882
Factors contributing to the gross margin increase (decrease) for the year ended December 31, 2015:	
Service Expansions	5,215
Additional Revenue from GRIP in Florida	4,151
Natural Gas Distribution Customer Growth	3,322
Weather and Other	(3,096)
FPU Electric Base Rate Increase	2,465
Growth in Natural Gas Transmission Services (Excluding Service Expansions)	938
Other	211
Gross margin for the year ended December 31, 2015	$ 179,088

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 due primarily to the following:

- $1.6 million from interruptible service that commenced in April 2015 to an industrial customer facility in Kent County, Delaware; the interruptible service was replaced by short-term OPT ≤ 90 Service in December 2015, which generated an additional $646,000 of gross margin;
- $1.4 million from a new service to the same industrial customer in Kent County, Delaware, that commenced in October 2014 upon completion of new facilities, which included approximately 5.5 miles of pipeline lateral and metering facilities extending from Eastern Shore's mainline to the new industrial customer facility;
- $334,000 in additional gross margin from a short-term contract with an existing industrial customer in New Castle County, Delaware to provide 50,000 Dts/d of service from April 2014 to April 2015, which was subsequently increased to 55,580 Dts/d of service at a lower reservation rate through August 2020; and
- $908,000 from natural gas transmission service, which was part of the major expansion initiative in Polk County, Florida.

Additional Revenue from GRIP in Florida

In 2015, our Florida natural gas distribution operations generated $4.2 million in additional gross margin as a result of additional GRIP expenditures.

FPU Electric Base Rate Increase

FPU's electric distribution operation generated additional gross margin of $2.5 million due to higher base rates approved in September 2014 as a result of the rate case settlement. The new rates became effective for all meter reads on or after November 1, 2014.

Natural Gas Distribution Customer Growth

Increased gross margin from other natural gas growth was generated primarily from the following:

- $1.9 million from Florida natural gas customer growth due primarily to new services to commercial and industrial customers; and
- $1.4 million from a 2.7 percent increase in residential customers in the Delmarva natural gas distribution operations, as well as growth in commercial and industrial customers in Worcester County, Maryland.

Growth in Natural Gas Transmission Services (Other Than Service Expansions)

Increased gross margin from other growth in natural gas transmission services was generated primarily from the following:

- $678,000 from natural gas transmission service to commercial customers in Florida, and
- $137,000 from interruptible service to an industrial customer in New Castle County, Delaware.

Decreased Customer Consumption—Weather and Other

In 2015, customer consumption of natural gas and electricity decreased as a result of near record high temperatures on the Delmarva Peninsula and in Florida during the fourth quarter, which reduced gross margin by approximately $3.1 million.

<u>Operating Expenses</u>

The increase in operating expenses was due primarily to:

- $2.9 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $2.8 million in higher staffing and associated costs as a result of additional personnel to support growth and increased overtime on the Delmarva Peninsula in early 2015 due to colder weather;
- $1.4 million in higher service contractor and other consulting costs;
- $987,000 in legal and consulting costs associated with the billing system settlement and other initiatives; and
- $480,000 in higher accruals for incentive compensation as a result of improved year-to-date financial performance; the foregoing increases were partially offset by:
- $1.5 million gain from a customer billing system settlement in 2015.

The non-recurring items added incremental operating income of $7.9 million in 2015, reflecting the absence of the $6.4 million asset impairment charge recorded in 2014, related to the then uncertainty about the implementation of a customer billing system, and receipt of $1.5 million in 2015 as part of a settlement with the vendor of the customer billing system.

UNREGULATED ENERGY

For the Year Ended December 31,	2016	2015	Increase (decrease)	2015	2014	Increase (decrease)
(in thousands)						
Revenue	**$ 203,778**	$ 162,108	$ 41,670	$ 162,108	$ 184,961	$ (22,853)
Cost of sales	**138,816**	101,791	37,025	101,791	137,081	(35,290)
Gross margin	**64,962**	60,317	4,645	60,317	47,880	12,437
Operations & maintenance	**42,659**	36,536	6,123	36,536	30,197	6,339
Asset impairment charges	—	—	—	—	432	(432)
Depreciation & amortization	**6,386**	5,679	707	5,679	3,994	1,685
Other taxes	**2,073**	1,747	326	1,747	1,534	213
Operating expenses	**51,118**	43,962	7,156	43,962	36,157	7,805
Operating Income	**$ 13,844**	$ 16,355	$ (2,511)	$ 16,355	$ 11,723	$ 4,632

2016 Compared to 2015

Operating income for the Unregulated Energy segment was $13.8 million, a decrease of $2.5 million, year-over-year. The decrease primarily reflects the impact of warmer weather, a return to more normal retail margins in the propane business and an operating loss generated by Xeron. Contributions from Aspire Energy, Eight Flags and our natural gas marketing business, 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.

Gross Margin

Items contributing to the year-over-year increase of $4.6 million, or 7.7 percent, in gross margin 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, 2015:	
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	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 to $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 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 level 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

Gross margin for 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 pays fixed storage and pipeline fees over the entire twelve-month period, although the projected volumes are expected to be highest in 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 for 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.

2015 Compared to 2014

Operating income for the Unregulated Energy segment was $16.4 million, an increase of $4.6 million, compared to 2014. The increase in operating income was due primarily to an increase in gross margin of $12.4 million and the absence of $432,000 in asset impairment charges, related to goodwill and intangible assets recorded in 2014, offset by an increase in other operating expenses of $8.2 million.

<u>Gross Margin</u>

Items contributing to the year-over-year increase of $12.4 million, or 26.0 percent, in gross margin were as follows:

(in thousands)	
Gross margin for the year ended December 31, 2014	$ 47,880
Factors contributing to the gross margin increase for the year ended December 31, 2015:	
Increased Retail Propane Margins	8,930
Aspire Energy	6,345
Decreased Customer Consumption - Weather and Other	(1,792)
Lower Margins from Xeron	(1,179)
Other	133
Gross margin for the year ended December 31, 2015	$ 60,317

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.

Increased Retail Propane Margins

Higher retail propane margins for our Delmarva Peninsula and Florida propane distribution operations during 2015 generated $7.0 million and $1.9 million, respectively, in additional gross margin. A large decline in wholesale propane prices during 2015, coupled with favorable supply management and hedging activities, resulted in a decrease in the average propane costs for the Delmarva propane distribution operation, which resulted in increased retail propane margins per gallon.

Aspire Energy

Aspire Energy generated $6.3 million in gross margin during 2015.

Decreased Customer Consumption - Weather and Other

Reduced consumption decreased gross margin in 2015 by $1.8 million. The decrease was mainly driven by weather due to record high temperatures during the fourth quarter of 2015 on the Delmarva Peninsula and by lower non-weather consumption in Florida.

Lower Margins for Xeron

Xeron's gross margin decreased by $1.2 million during 2015, compared to 2014, as a result of a 14-percent decrease in trading activity and lower margins on executed trades. In contrast, Xeron experienced higher price volatility and higher trading volumes in 2014, which resulted in unusually high profitability during that year.

Operating Expenses

Operating expenses increased by $7.8 million in 2015, due primarily to $5.8 million of operating expenses incurred by Aspire Energy, which commenced operations on April 1, 2015. The remaining increase in operating expenses was due primarily to:

- $1.4 million in higher staffing and associated costs due to increased seasonal overtime and additional resources hired to support growth;
- $553,000 in additional costs for facility maintenance; and
- $411,000 in increased accruals for incentive compensation as a result of improved year-to-date financial results in 2015, as well as a larger workforce.

GAIN FROM SALE OF BUSINESSES

In October 2014, we completed the sale of BravePoint for approximately $12.0 million. We recorded a pre-tax gain of approximately $6.7 million ($4.0 million after-tax) from this sale in the fourth quarter of 2014. We reinvested the proceeds from this sale in our regulated and unregulated energy businesses. We also recorded a gain of $396,000 from the sale of the Florida fuel line maintenance business in April 2014. No businesses were sold in 2015 or 2016.

OTHER INCOME (EXPENSE)

Other income (expense) for 2016, 2015, and 2014 was $441,000, $293,000 and $101,000, respectively, which includes non-operating investment income, interest income, late fees charged to customers and gains or losses from the sale of assets.

INTEREST EXPENSE

2016 Compared to 2015

Interest charges for 2016 increased by approximately $633,000, or 6 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.

2015 Compared to 2014

Interest charges for 2015 increased by approximately $524,000, or 6 percent, compared to 2014. The increase is attributable an increase of $356,000 in interest expense from higher short-term borrowings and an increase of $95,000, in long-term interest charges as a result of $50.0 million of Senior Notes issued in May 2014.

Income Taxes

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.

2015 Compared to 2014
Income tax expense was $26.9 million for 2015, compared to $23.9 million in 2014. The increase was due primarily to higher taxable income. Our effective tax rate was 39.5 percent in 2015 compared to 39.9 percent in 2014.

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 actual 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 natural gas, electric, and propane 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 $169.4 million in 2016, $195.2 million ($142.7 million excluding $52.5 million, net of cash received, spent on the Gatherco acquisition) in 2015 and $98.1 million in 2014. The most significant capital expenditures in 2016 included investments in GRIP in Florida, Eight Flags' CHP Plant, and Eastern Shore's System Reliability and White Oak Mainline Projects.

We have budgeted $260.3 million for capital expenditures in 2017. The following table shows the 2017 capital expenditure budget by segment and by business line:

(dollars in thousands)		
Regulated Energy:		
Natural gas distribution	$	80,829
Natural gas transmission		136,087
Electric distribution		15,070
Total Regulated Energy		231,986
Unregulated Energy:		
Propane distribution		11,153
Other unregulated energy		5,196
Total Unregulated Energy		16,349
Other:		
Corporate and other businesses		11,981
Total Other		11,981
Total 2017 Capital Expenditures	$	260,316

The 2017 budget represents a significant increase over the prior years' level of capital expenditures, excluding acquisitions, due to additional expansions of our natural gas distribution and transmission systems; continued natural gas infrastructure improvement activities; expenditures for continued replacement under the Florida GRIP; replacement of several office and operational facilities and information technology systems; and other strategic initiatives and investments.

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 94 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, 2016 and 2015:

(in thousands)	December 31, 2016		December 31, 2015	
Long-term debt, net of current maturities	**$ 136,954**	**23%**	$ 149,006	29%
Stockholders' equity	**446,086**	**77%**	358,138	71%
Total capitalization, excluding short-term borrowings	**$ 583,040**	**100%**	$ 507,144	100%

(in thousands)	December 31, 2016		December 31, 2015	
Short-term debt	**$ 209,871**	**26%**	$ 173,397	25%
Long-term debt, including current maturities	**149,053**	**19%**	158,157	23%
Stockholders' equity	**446,086**	**55%**	358,138	52%
Total capitalization, including short-term borrowings	**$ 805,010**	**100%**	$ 689,692	100%

Included in the long-term debt balances at December 31, 2016, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($2.1 million excluding current maturities and $3.5 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, 2016, 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, 2016, $172.3 million of Chesapeake Utilities' cumulative consolidated net income and $90.9 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. The issuance of equity resulted in our equity to total capitalization ratio of 55 percent as of December 31, 2016.

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 a long-term Shelf Agreement with Prudential for the potential private placement of Shelf Notes as further described below under the heading "Shelf Agreement."

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 Agreement

In October 2015, we entered into a Shelf Agreement with Prudential. Under the terms of the Shelf Agreement, we may request, through October 8, 2018, that Prudential purchase up to $150.0 million of our Shelf Notes at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance. Prudential is under no obligation to purchase any of the Shelf Notes. The interest rate and terms of payment of any series of Shelf Notes will be determined at the time of purchase. We currently anticipate the proceeds from the sale of any series of Shelf Notes will be used for general corporate purposes, including refinancing of short-term borrowing and/or repayment of outstanding indebtedness and financing capital expenditures on future projects; however, actual use of such proceeds will be determined at the time of a purchase.

In May 2016, we submitted a request that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. In May 2016, Prudential accepted and confirmed our request. The proceeds received from the issuances of the Shelf Notes will be used to reduce short-term borrowings under our revolving credit facility, lines of credit and/or to fund capital expenditures. The closing of the sale and issuance of the Shelf Notes is expected to occur on or before April 28, 2017.

The Shelf Agreement sets forth certain business covenants to which we are subject when any Shelf Note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, 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, 2016 and 2015 were $209.9 million and $173.4 million, respectively, at the weighted average interest rates of 1.43 percent and 1.30 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. As of December 31, 2016, we had four unsecured bank credit facilities with three financial institutions totaling $170.0 million in total 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. We also had access to two credit facilities with a total of $40.0 million of available credit. The Revolver replaced these credit facilities when they expired on October 31, 2015. 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.

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, 2016 and 2015 included $8.6 million and $4.6 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 if presented and, therefore, were included in the short-term borrowings.

As of December 31, 2016, we had issued $8.5 million in letters of credit to various counterparties under one of the bank lines of credit. Although the amount of the letters of credit is 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 credit facilities.

Our outstanding borrowings under these unsecured short-term credit facilities at December 31, 2016 and 2015 were $201.3 million and $168.8 million, respectively. Short-term borrowings were as follows during 2016, 2015 and 2014:

(in thousands)	**2016**	2015	2014
Average borrowings	**$ 129,721**	$ 102,062	$ 68,928
Weighted average interest rate	**1.41%**	1.22%	1.28%
Maximum month-end borrowings	**$ 201,311**	$ 168,757	$ 86,040

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the years ended December 31, 2016, 2015 and 2014:

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Net cash provided by (used in):			
Operating activities	**$ 103,371**	$ 104,123	$ 73,708
Investing activities	**(170,037)**	(164,539)	(81,010)
Financing activities	**67,989**	58,697	8,520
Net increase (decrease) in cash and cash equivalents	**1,323**	(1,719)	1,218
Cash and cash equivalents—beginning of period	**2,855**	4,574	3,356
Cash and cash equivalents—end of period	**$ 4,178**	$ 2,855	$ 4,574

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 2016 and 2015, net cash provided by operating activities was $103.4 million and $104.1 million, respectively, resulting in a decrease in cash flows of $752,000 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 $13.4 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.

During 2015 and 2014, net cash provided by operating activities was $104.1 million and $73.7 million, respectively, resulting in an increase in cash flows of $30.4 million in 2015. Significant operating activities generating the cash flow change were as follows:

- The changes in net regulatory assets and liabilities increased cash flows by $14.9 million, due primarily to the change in fuel costs collected through the various fuel cost recovery mechanisms.
- The change in income taxes receivable increased cash flows by $11.0 million, due primarily to the receipt of a tax refund related to our 2014 federal income tax obligation. Our tax deductions, which were higher than projected, due to bonus depreciation, reduced our 2014 federal income tax obligation.
- Net income, adjusted for non-cash adjustments and reconciling activities, increased cash flows by $7.6 million, due primarily to higher earnings and higher non-cash adjustments for depreciation and amortization.
- Changes in customer deposits and refunds increased cash flows by $2.9 million.

- Changes in net accounts receivable and payable decreased cash flows by $1.9 million, due primarily to the timing of the collections and payments associated with trading contracts entered into by our propane wholesale and marketing subsidiary and net cash flows from accounts receivable and payable attributed to Aspire Energy. This decrease was partially offset by an increase in net cash flow from receivables and payables in various other operations.
- Net cash flows from changes in propane, natural gas and materials inventories decreased by approximately $2.7 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $170.0 million and $164.5 million for 2016 and 2015, respectively, resulting in an increase 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 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.

Net cash used in investing activities totaled $164.5 million and $81.0 million for 2015 and 2014, respectively, resulting in a decrease in cash flows of $83.5 million. 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 and Eight Flags' construction of the CHP plant, which decreased cash flows by $52.0 million.
- The $20.7 million in cash, noted above, related to the acquisition of Gatherco.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities totaled $68.0 million and $58.7 million for 2016 and 2015, respectively, resulting in an increase of $9.3 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.

Net cash provided by financing activities totaled $58.7 million and $8.5 million for 2015 and 2014, respectively, resulting in an increase of $50.2 million in 2015. Significant financing activities generating the cash flow change were as follows:

- Net borrowings/repayments under the line of credit agreements increased cash flows by $98.7 million due to an increase in short-term borrowing, which includes the $35.0 million we borrowed under the Revolver. In 2014, we used the proceeds from the issuance of $50.0 million of the 3.88 percent Senior Notes to repay borrowings under our lines of credit arrangements.
- Book overdrafts decreased cash flows by $3.4 million.
- Net proceeds from and repayments of long-term debt decreased cash flows by $50.8 million due primarily to the $50.0 million issuance of the 3.88 percent Senior Notes in May 2014.

CONTRACTUAL OBLIGATIONS

We have the following contractual obligations and other commercial commitments as of December 31, 2016:

Contractual Obligations	Payments Due by Period: Less than 1 year	1 — 3 years	3 — 5 years	More than 5 years	Total
(in thousands)					
Long-term debt [1]	$ 10,698	$ 18,597	$ 29,200	$ 87,400	$ 145,895
Operating leases [2]	1,389	1,904	1,150	2,318	6,761
Capital leases [2]	1,401	2,070	—	—	3,471
Purchase obligations [3]					
Transmission capacity	30,042	55,740	38,708	81,833	206,323
Storage capacity	1,741	2,262	755	354	5,112
Commodities	41,760	2,967	—	—	44,727
Electric supply	16,477	33,608	—	—	50,085
Unfunded benefits [4]	388	704	894	1,456	3,442
Funded benefits [5]	2,880	—	—	4,881	7,761
Total Contractual Obligations	**$ 106,776**	**$ 117,852**	**$ 70,707**	**$ 178,242**	**$ 473,577**

(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 $7.2 million, $12.6 million, $10.0 million and $11.9 million, respectively, for the periods indicated above. Expected interest payments for all periods total $41.7 million.

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

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

(4) We have recorded long-term liabilities of $3.4 million at December 31, 2016 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 Plan*s, for further information on the plans.

(5) We have recorded long-term liabilities of $23.2 million at December 31, 2016 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 $2.9 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 $4.9 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 Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. Neither of these subsidiaries has ever 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, 2016 was $57.2 million, with the guarantees expiring on various dates through January 1, 2018.

We have issued letters of credit totaling $8.5 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 October 5, 2017. There have been no draws on these letters of credit as of December 31, 2016. 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. Costs are deferred when there is a probable expectation that they will be recovered in future revenues 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 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 also use derivative instruments to engage in propane and crude oil wholesale marketing activities as well as crude oil trading. 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 Consolidated Financial Statements.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC of each state in which we operate. Customers' base rates may not be changed without formal approval by these PSCs. However, 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.

We record trading activity for open propane and crude oil wholesale marketing contracts on a net mark-to-market basis in the 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.

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 of each year. The testing of goodwill for 2016 indicated no goodwill impairment. 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 indicating that an impairment is present, we record an impairment loss equal to the excess of the assets' 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 2016, 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 3.75 percent and 4.00 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 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 $15,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $14,000.

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 $129,000 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 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 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, 2016 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 6.2 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.

Xeron trades in short-term natural gas liquids and crude oil forward and futures contracts on the InterContinentalExchange, Inc. Xeron settles its purchases and sales financially, without taking physical delivery of the propane or crude oil. The level and profitability of the propane and crude oil wholesale marketing trading activity is affected by both propane and crude oil wholesale price volatility and liquidity in the wholesale market. At December 31, 2016, Xeron did not have any open natural gas liquids contracts or crude oil forward or futures contracts.

PESCO is a party to natural gas 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.

Xeron and PESCO are subject to commodity price risk on their 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.

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.

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

We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation (the “Company”) as of December 31, 2016 and 2015, and 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, 2016. These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 27, 2017 expressed an unqualified opinion.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
February 27, 2017

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Income

(in thousands, except shares and per share data)	For the Year Ended December 31, 2016	2015	2014
Operating Revenues			
Regulated Energy	**$ 305,689**	$ 301,902	$ 300,442
Unregulated Energy	**203,778**	162,108	184,961
Other businesses and eliminations	**(10,607)**	(4,766)	13,431
Total operating revenues	**498,860**	459,244	498,834
Operating Expenses			
Regulated energy cost of sales	**109,609**	122,814	134,560
Unregulated energy and other cost of sales	**128,434**	97,228	143,556
Operations	**117,571**	107,562	102,197
Maintenance	**12,391**	11,803	9,706
(Gain from a settlement)/asset impairment charges	**(130)**	(1,500)	6,881
Depreciation and amortization	**32,159**	29,972	26,316
Other taxes	**14,730**	13,607	13,339
Total operating expenses	**414,764**	381,486	436,555
Operating Income	**84,096**	77,758	62,279
Gains from sales of businesses	**—**	—	7,139
Other (expense) income	**(441)**	293	101
Interest charges	**10,639**	10,006	9,482
Income Before Income Taxes	**73,016**	68,045	60,037
Income taxes	**28,341**	26,905	23,945
Net Income	**$ 44,675**	$ 41,140	$ 36,092
Weighted Average Common Shares Outstanding:			
Basic	**15,570,539**	15,094,423	14,551,308
Diluted	**15,613,091**	15,143,373	14,604,944
Earnings Per Share of Common Stock:			
Basic	**$ 2.87**	$ 2.73	$ 2.48
Diluted	**$ 2.86**	$ 2.72	$ 2.47
Cash Dividends Declared Per Share of Common Stock	**$ 1.2025**	$ 1.1325	$ 1.0667

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)	**2016**	**2015**	**2014**
Net Income	**$ 44,675**	$ 41,140	$ 36,092
Other Comprehensive Income (Loss), net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of ($29), $(27) and $(24), respectively	**(48)**	(40)	(34)
Net gain (loss), net of tax of $178, $73, and $(1,997), respectively	**268**	103	(3,076)
Cash Flow Hedges, net of tax:			
Unrealized gain (loss) on commodity contract cash flow hedges, net of tax of $496, $(150) and $(22), respectively	**742**	(227)	(33)
Total Other Comprehensive Income (Loss)	**962**	(164)	(3,143)
Comprehensive Income	**$ 45,637**	$ 40,976	$ 32,949

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

Assets	As of December 31, 2016	2015
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	**$ 957,681**	$ 842,756
Unregulated energy	**196,800**	145,734
Other businesses and eliminations	**21,114**	18,999
Total property, plant and equipment	**1,175,595**	1,007,489
Less: Accumulated depreciation and amortization	**(245,207)**	(215,313)
Plus: Construction work in progress	**56,276**	62,774
Net property, plant and equipment	**986,664**	854,950
Current Assets		
Cash and cash equivalents	**4,178**	2,855
Accounts receivable (less allowance for uncollectible accounts of $909 for 2016 and 2015)	**62,803**	41,007
Accrued revenue	**16,986**	12,452
Propane inventory, at average cost	**6,457**	6,619
Other inventory, at average cost	**4,576**	3,803
Regulatory assets	**7,694**	8,268
Storage gas prepayments	**5,484**	3,410
Income taxes receivable	**22,888**	24,950
Prepaid expenses	**6,792**	7,146
Mark-to-market energy assets	**823**	153
Other current assets	**2,470**	1,044
Total current assets	**141,151**	111,707
Deferred Charges and Other Non-Current Assets		
Goodwill	**15,070**	14,548
Other intangible assets, net	**1,843**	2,222
Investments, at fair value	**4,902**	3,644
Regulatory assets	**76,803**	77,519
Receivables and other deferred charges	**2,786**	2,831
Total deferred charges and other non-current assets	**101,404**	100,764
Total Assets	**$ 1,229,219**	$ 1,067,421

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

	As of December 31,	
Capitalization and Liabilities	**2016**	**2015**
(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 $0.4867 per share (authorized 25,000,000 shares)	**7,935**	7,432
Additional paid-in capital	**250,967**	190,311
Retained earnings	**192,062**	166,235
Accumulated other comprehensive loss	**(4,878)**	(5,840)
Deferred compensation obligation	**2,416**	1,883
Treasury stock	**(2,416)**	(1,883)
Total stockholders' equity	**446,086**	358,138
Long-term debt, net of current maturities	**136,954**	149,006
Total capitalization	**583,040**	507,144
Current Liabilities		
Current portion of long-term debt	**12,099**	9,151
Short-term borrowing	**209,871**	173,397
Accounts payable	**56,935**	39,300
Customer deposits and refunds	**29,238**	27,173
Accrued interest	**1,312**	1,311
Dividends payable	**4,973**	4,390
Accrued compensation	**10,496**	10,014
Regulatory liabilities	**1,291**	7,365
Mark-to-market energy liabilities	**773**	433
Other accrued liabilities	**7,063**	7,059
Total current liabilities	**334,051**	279,593
Deferred Credits and Other Liabilities		
Deferred income taxes	**222,894**	192,600
Regulatory liabilities	**43,064**	43,064
Environmental liabilities	**8,592**	8,942
Other pension and benefit costs	**32,828**	33,481
Deferred investment tax credits and other liabilities	**4,750**	2,597
Total deferred credits and other liabilities	**312,128**	280,684
Other commitments and contingencies (Note 19 and 20)		
Total Capitalization and Liabilities	**$ 1,229,219**	$ 1,067,421

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Operating Activities			
Net Income	**$ 44,675**	$ 41,140	$ 36,092
Adjustments to reconcile net income to net operating cash:			
Goodwill & long-lived asset impairment	**—**	—	6,881
Depreciation and amortization	**32,159**	29,972	26,316
Depreciation and accretion included in other costs	**7,334**	6,978	6,577
Deferred income taxes, net	**31,257**	20,520	22,235
Realized loss (gain) on sale of assets/investments	**695**	(340)	(7,293)
Unrealized (gain) loss on investments/commodity contracts	**(385)**	96	501
Employee benefits and compensation	**1,887**	1,235	684
Share-based compensation	**2,367**	1,937	1,958
Other, net	**(79)**	47	3
Changes in assets and liabilities:			
Accounts receivable and accrued revenue	**(27,013)**	17,097	20,683
Propane inventory, storage gas and other inventory	**(2,531)**	1,527	4,177
Regulatory assets/liabilities, net	**(7,523)**	3,883	(11,014)
Prepaid expenses and other current assets	**(1,387)**	(759)	(699)
Accounts payable and other accrued liabilities	**18,829**	(11,916)	(13,623)
Income taxes receivable	**2,466**	(4,967)	(15,936)
Customer deposits and refunds	**2,065**	1,976	(927)
Accrued compensation	**358**	(331)	37
Other assets and liabilities, net	**(1,803)**	(3,972)	(2,944)
Net cash provided by operating activities	**103,371**	104,123	73,708
Investing Activities			
Property, plant and equipment expenditures	**(169,861)**	(143,599)	(91,588)
Change in intangibles	**—**	—	14
Proceeds from sale of assets	**174**	164	10,797
Acquisitions, net of cash acquired	**—**	(20,930)	—
Environmental expenditures	**(350)**	(174)	(233)
Net cash used by investing activities	**(170,037)**	(164,539)	(81,010)
Financing Activities			
Common stock dividends	**(17,482)**	(15,924)	(13,887)
Issuance (Purchase) of stock for Dividend Reinvestment Plan	**811**	813	(165)
Proceeds from issuance of common stock, net of expenses	**57,360**	—	—
Change in cash overdrafts due to outstanding checks	**3,920**	2,450	(921)
Net borrowing (repayment) under line of credit agreements	**32,526**	82,178	(16,513)
Proceeds from issuance of long-term debt	**—**	—	49,975
Repayment of long-term debt and capital lease obligation	**(9,146)**	(10,820)	(9,969)
Net cash provided by financing activities	**67,989**	58,697	8,520
Net Increase (Decrease) in Cash and Cash Equivalents	**1,323**	(1,719)	1,218
Cash and Cash Equivalents — Beginning of Period	**2,855**	4,574	3,356
Cash and Cash Equivalents — End of Period	**$ 4,178**	$ 2,855	$ 4,574

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, 2013	**14,457,345**	**$ 4,691**	**$ 152,341**	**$ 124,274**	**$ (2,533)**	**$ 1,124**	**$ (1,124)**	**$ 278,773**
Net Income	—	—	—	36,092	—	—	—	**36,092**
Other comprehensive income	—	—	—	—	(3,143)	—	—	**(3,143)**
Dividends declared ($1.0667 per share)	—	—	—	(15,675)	—	—	—	**(15,675)**
Retirement savings plan and dividend reinvestment plan	43,367	16	1,844	—	—	—	—	**1,860**
Conversion of Debentures	47,313	15	520	—	—	—	—	**535**
Share-based compensation and tax benefit [4] [5]	40,686	13	1,876	—	—	—	—	**1,889**
Stock split in the form of stock dividend	—	2,365	—	(2,374)	—	—	—	**(9)**
Treasury stock activities[2]	—	—	—	—	—	134	(134)	—
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**

(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 76,745, 70,631 and 57,382 shares at December 31, 2016, 2015 and 2014, 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 2016, 2015 and 2014, we withheld 12,031, 12,620 and 12,687 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 and the eastern shore of Virginia, southeastern Pennsylvania and Florida; (b) our propane and crude oil wholesale marketing operation, which markets propane and crude oil to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States; (c) our natural gas marketing operation providing natural gas supplies directly to commercial and industrial customers in Florida, Delaware, Maryland, Ohio and other states; (d) our natural gas supply, gathering and processing operation in central and eastern Ohio; and (e) 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 balance sheets as of December 31, 2015 to conform to the current year's presentation. We have also revised the consolidated statements of cash flows for the years ended December 31, 2015 and 2014 to reflect only property, plant and equipment expenditures paid in cash within the Investing Activities section. The non-cash expenditures previously included in that section have now been included in the change in accounts payable and other accrued liabilities amount within the Operating Activities section. These revisions are considered immaterial to the overall presentation of our consolidated financial statements.

Previously reported share and per share amounts have been restated in the accompanying consolidated financial statements and related notes to reflect the stock split effected in the form of a stock dividend in September 2014.

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.

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, 2016 and 2015 is provided in the following table:

(in thousands)	As of December 31, 2016	2015
Property, plant and equipment		
Regulated Energy		
Natural gas distribution – Delmarva	**$ 220,083**	$ 207,127
Natural gas distribution – Florida	**331,281**	286,538
Natural gas transmission – Delmarva	**285,746**	249,274
Natural gas transmission – Florida	**27,018**	20,291
Electric distribution – Florida	**93,553**	79,526
Unregulated Energy		
Propane distribution – Delmarva	**73,686**	66,403
Propane distribution – Florida	**26,359**	24,589
Other Unregulated natural gas services – Ohio	**61,383**	54,607
CHP - Florida	**35,237**	—
Other unregulated energy	**135**	135
Other	**21,114**	18,999
Total property, plant and equipment	**1,175,595**	1,007,489
Less: Accumulated depreciation and amortization	**(245,207)**	(215,313)
Plus: Construction work in progress	**56,276**	62,774
Net property, plant and equipment	**$ 986,664**	$ 854,950

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, 2016 and 2015, there were $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, 2016, 2015 and 2014, 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, 2016 and 2015, 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 term of 20 years. Accumulated depreciation for these assets totaled $580,000 and $507,000 at December 31, 2016 and 2015, respectively.

Capital Lease Asset

Property, plant and equipment for our Delmarva natural gas distribution operation included a capital lease asset of $3.5 million and $4.8 million, net of accumulated amortization, at December 31, 2016 and 2015, 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, 2016 and 2015, accumulated amortization for this capital lease asset was $3.7 million and $2.3 million, respectively. For the years ended December 31, 2016 and 2015, we recorded $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 the Florida natural gas transmission operation also included $6.7 million of assets, at December 31, 2016 and 2015, 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 $1.0 million and $806,000, at December 31, 2016 and 2015, 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. When such events or circumstances are present, we record an impairment loss equal to the excess of the assets' 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. Previously, at December 31, 2014, we recorded a $6.5 million pre-tax, non-cash impairment loss related to the same billing system implementation. We recorded $6.4 million of this impairment loss in the Regulated Energy segment, with the balance included in the Unregulated Energy segment. In May 2016, we received $650,000 in cash, however, the retention of this amount is contingent upon engaging this vendor to provide agreed-upon services through May 2020.

Depreciation and Accretion Included in Operations Expenses

We compute depreciation expense for our regulated operations by applying composite, annual rates, as approved by the respective regulatory bodies. The following table shows the average depreciation rates used for regulated operations during the years ended December 31, 2016, 2015 and 2014:

	2016	**2015**	**2014**
Natural gas distribution – Delmarva	**2.5%**	2.4%	2.5%
Natural gas distribution – Florida	**2.9%**	2.9%	2.9%
Natural gas transmission – Delmarva	**2.7%**	2.7%	2.7%
Natural gas transmission – Florida	**3.9%**	4.0%	4.0%
Electric distribution – Florida	**3.5%**	3.5%	3.8%

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, 2016, 2015 and 2014, we reported \$7.3 million, \$7.0 million and \$6.6 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.

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 natural gas distribution 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, steam and electricity generation costs, and for the period prior to the sale of BravePoint, the direct cost of labor for our former advanced information services subsidiary. 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 market values. There was no lower-of-cost-or-market adjustment during 2016 and 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 fair value. The testing of goodwill for 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 $15,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $14,000. A 0.25 percent change in the rate of return could change our annual pension cost by approximately $129,000 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 the 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 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

Xeron engages in trading activities using forward and futures contracts, which have been accounted for using the mark-to-market method of accounting. Under mark-to-market accounting, our trading contracts are recorded at fair value as mark-to-market energy assets and liabilities. The changes in fair value of the contracts are 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 may 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 contracts to mitigate any price risk associated with the purchase and/or sale of natural gas sales 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.

FASB Statements

Recently Adopted Accounting Standards

Interest - Imputation of Interest (ASC 835-30) - In April 2015, the FASB issued ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. This standard requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. ASU 2015-03 became effective for us on January 1, 2016, and we applied the provisions of this standard on a retrospective basis. As a result of the adoption of this standard, debt issuance costs totaling $291,000 and $333,000 at December 31, 2016 and 2015, respectively, previously treated as other deferred charges, a non-current asset, are now deducted from long-term debt, net of current maturities in the accompanying consolidated balance sheet.

Intangibles-Goodwill and Other-Internal-Use Software (ASC 350-40) - In April 2015, the FASB issued ASU 2015-05, *Customer's Accounting for Fees Paid in a Cloud Computing Arrangement.* Under the new standard, unless a software arrangement includes specific elements enabling customers to possess and operate software on platforms other than that offered by the cloud-based provider, the cost of such arrangements is to be accounted for as an operating expense in the period incurred. ASU 2015-05 became effective for us on January 1, 2016, and has been applied on a prospective basis. The application of this standard did not have a material impact on our financial position or results of operations.

Fair Value Measurement (ASC 820) - In May 2015, the FASB issued ASU No. 2015-07, *Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*. ASU 2015-07 removes the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value practical expedient in ASC 820. We adopted ASU 2015-07 on January 1, 2016 on a retrospective basis, by excluding such investments from the fair value hierarchy table for pension plan assets. See Note 16, *Employee Benefit Plans,* for fair value measurement information related to our pension plan assets.

Interest-Imputation of Interest (ASC 835-30) - In August 2015, the FASB issued ASU 2015-15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. This standard clarifies treatment of debt issuance costs associated with line-of-credit arrangements that were not specifically addressed in ASU 2015-03. Issuance costs incurred in connection with line-of-credit arrangements may be treated as an asset and amortized over the term of the line-of-credit arrangement. ASU 2015-15 became effective for us on January 1, 2016. The adoption of the standard did not have a material impact on our financial position or results of operations.

Business Combinations (ASC 805) - In September 2015, the FASB issued ASU 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments*. The standard eliminates the requirement to restate prior period financial statements for measurement period adjustments and requires that the cumulative impact of measurement-period adjustments (including the impact of prior periods) be recognized in the reporting period in which the adjustment is identified. ASU 2015-16 was effective for our interim and annual financial statements issued after January 1, 2016 and was adopted on a prospective basis. Adoption of this standard did not have a material impact on our financial position or results of operations.

Income Taxes (ASC 740) - In November 2015, the FASB issued ASU 2015-17, *Balance Sheet Classification of Deferred Taxes,* which requires all deferred assets and liabilities along with any related valuation allowance to be classified as noncurrent on the balance sheet for our annual financial statements beginning January 1, 2017 and for our interim financial statements beginning January 1, 2018; however, early adoption is permitted. We adopted this standard in the first quarter of 2016 on a retrospective basis and adjusted the December 31, 2015 consolidated balance sheet.

Compensation-Stock Compensation (ASC 718) - In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting,* which simplifies several aspects of accounting for employee share-based payment transactions, including accounting for income taxes, forfeitures, and statutory tax withholding requirements, and classification in the statement of cash flows. Most significantly, entities are required to recognize all excess tax benefits and deficiencies related to the exercise or vesting of stock compensation as income tax expense or benefit in the income statement. ASU 2016-09 will be effective for our annual and interim financial statements beginning January 1, 2017; however, we have elected early adoption. Effective December 31, 2016, on a prospective basis, we recognized excess tax benefits related to the exercise and vesting of stock compensation as income expense rather than in additional paid-in capital. We do not have any previously unrecognized excess tax benefits which require a cumulative effect adjustment upon adoption. The adoption of the 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. 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 our interim and annual financial statements issued beginning January 1, 2018.

In preparation for the adoption of this standard, we have analyzed our existing businesses and revenue streams and have prepared a preliminary gap analysis between our current revenue policies and the requirements under the new revenue recognition standard. We are in the process of evaluating each revenue stream under the new standard, expanding the contract sampling, creating new policies and evaluating the enhanced disclosure requirements. We will provide additional training to our employees and develop processes and system changes associated with the implementation of the new standard, and we will then implement the standard. We plan to utilize the Modified Retrospective Transition Method upon adoption of this standard.

Based on our assessment, we do not believe the new standard will impact the recognition of revenue from a majority of our customers. However, we have just begun to evaluate our long term special contracts, and may find facts and circumstances in those contracts that could impact the timing of the recognition of revenue. As we continue to execute our plan related to this standard, we will be in a better position to quantify the full impact of this standard.

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. ASU 2015-11 will be effective for our interim and annual financial statements issued beginning January 1, 2017 although early adoption is permitted. The standard is to be adopted on a prospective basis. We are assessing the impact this standard may have on our financial position and results of operations.

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. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are evaluating the effect this update may have on our financial position and results of operations.

Statement of Cash Flows (ASC 230) -In August, 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 are assessing the impact of the adoption of this ASU on our statements 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 update are to be applied prospectively. We are evaluating the effect of this update on our 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:

	For the Year Ended December 31,		
(in thousands, except shares and per share data)	**2016**	**2015**	**2014**
Calculation of Basic Earnings Per Share:			
Net Income	**$ 44,675**	$ 41,140	$ 36,092
Weighted average shares outstanding	**15,570,539**	15,094,423	14,551,308
Basic Earnings Per Share	**$ 2.87**	$ 2.73	$ 2.48
Calculation of Diluted Earnings Per Share:			
Net Income	**$ 44,675**	$ 41,140	$ 36,092
Reconciliation of Denominator:			
Weighted average shares outstanding — Basic	**15,570,539**	15,094,423	14,551,308
Effect of dilutive securities — Share-based compensation	**42,552**	48,950	53,636
Adjusted denominator — Diluted	**15,613,091**	15,143,373	14,604,944
Diluted Earnings Per Share	**$ 2.86**	$ 2.72	$ 2.47

4. Acquisition and Disposition

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 years following the closing. As of December 31, 2016, there have been no related gathering opportunities developed; therefore, no contingent consideration 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 accompanying consolidated statements of income. The revenues and net income from this acquisition for the years ended December 31, 2016 and 2015, included in our consolidated statements of income, were $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. The allocation of the purchase price and valuation of assets is final.

Disposition of BravePoint

On October 1, 2014, we completed the sale of BravePoint, our former advanced information services subsidiary, for approximately $12.0 million in cash. We reinvested the proceeds from this sale in our regulated and unregulated energy businesses. We recorded a pre-tax gain of $6.7 million (approximately $4.0 million after-tax) from this sale, which included the effect of certain costs and expenses associated with the sale. Our consolidated statement of income for the year ended December 31, 2014, included $15.1 million of revenue and $232,000 of net loss from BravePoint's operations.

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, propane and crude oil wholesale marketing and natural gas marketing operations, which are unregulated as to their rates and services. Effective April 2015, this segment includes Aspire Energy, whose services include natural gas gathering, processing, transportation and supply (See Note 4, *Acquisitions and Dispositions*, regarding the merger with Gatherco). Effective June 2016, this segment also includes electricity and steam generation through Eight Flags' CHP plant. 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. We had previously identified "Other" as a separate reportable segment, which consisted primarily of BravePoint, our former advanced information services subsidiary. As a result of the sale of that subsidiary in October 2014, "Other" is no longer a separate reportable segment.

The following table presents information about our reportable segments.

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Operating Revenues, Unaffiliated Customers			
Regulated Energy	**$ 302,402**	$ 300,674	$ 299,345
Unregulated Energy	**196,458**	158,570	184,557
Other businesses and eliminations	**—**	—	14,932
Total operating revenues, unaffiliated customers	**$ 498,860**	$ 459,244	$ 498,834
Intersegment Revenues [1]			
Regulated Energy	**$ 3,287**	$ 1,228	$ 1,097
Unregulated Energy	**7,321**	3,537	404
Other businesses	**880**	880	979
Total intersegment revenues	**$ 11,488**	$ 5,645	$ 2,480
Operating Income			
Regulated Energy	**$ 69,851**	$ 60,985	$ 50,451
Unregulated Energy	**13,844**	16,355	11,723
Other businesses and eliminations	**401**	418	105
Operating Income	**84,096**	77,758	62,279
Gains from sales of businesses	**—**	—	7,139
Other (expense) income	**(441)**	293	101
Interest charges	**10,639**	10,006	9,482
Income Before Income taxes	**73,016**	68,045	60,037
Income taxes	**28,341**	26,905	23,945
Net Income	**$ 44,675**	$ 41,140	$ 36,092
Depreciation and Amortization			
Regulated Energy	**$ 25,677**	$ 24,195	$ 21,915
Unregulated Energy	**6,386**	5,679	3,994
Other businesses and eliminations	**96**	98	407
Total depreciation and amortization	**$ 32,159**	$ 29,972	$ 26,316
Capital Expenditures			
Regulated Energy	**$ 139,994**	$ 98,372	$ 84,959
Unregulated Energy	**23,984**	38,347	9,648
Other businesses	**5,398**	5,994	3,450
Total capital expenditures	**$ 169,376**	$ 142,713	$ 98,057

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

	As of December 31,	
	2016	**2015**
Identifiable Assets		
Regulated Energy	**$ 986,752**	$ 872,065
Unregulated Energy	**226,368**	171,840
Other businesses	**16,099**	23,516
Total identifiable assets	**$ 1,229,219**	$ 1,067,421

Our operations are now entirely domestic. Previously, BravePoint, our formerly owned advanced information services subsidiary, had infrequent transactions in foreign countries, which were denominated and paid primarily in U.S. dollars. These transactions were immaterial to our consolidated revenues.

6. SUPPLEMENTAL CASH FLOW DISCLOSURES

Cash paid for interest and income taxes during the years ended December 31, 2016, 2015 and 2014 were as follows:

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Cash paid for interest	$ 10,315	$ 9,497	$ 8,870
Cash paid for income taxes, net of refunds	$ (5,308)	$ 11,076	$ 17,588

Non-cash investing and financing activities during the years ended December 31, 2016, 2015, and 2014 were as follows:

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Capital property and equipment acquired on account, but not paid for as of December 31	$ 9,791	$ 10,268	$ 7,040
Common stock issued for the Retirement Savings Plan	$ 777	$ 690	$ 602
Common stock issued for the conversion of debentures	$ —	$ —	$ 535
Common stock issued under the SICP	$ 1,027	$ 1,594	$ 1,533
Capital lease obligation	$ 3,471	$ 4,824	$ 6,130
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 supplies 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, 2016, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2016

In 2016, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 4.8 million gallons expected to be purchased through September 2017, of which 4.1 million gallons were outstanding at December 31, 2016. Under the swap agreements, Sharp will receive the difference between the index prices (Mont Belvieu prices in October 2016 through September 2017) and the swap prices, which range between $0.5225 and $0.5650 per gallon, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap price, Sharp will pay the difference. The swap agreement essentially fixed the price of the 4.8 million gallons that we expect to purchase through September 2017. We accounted for these swap agreements as cash flow hedges, and there is no ineffective portion of these hedges. At December 31, 2016, the outstanding swap agreements had a fair value of approximately $693,000. The change in the fair value of the swap agreements is recorded as unrealized gain/loss in other comprehensive income (loss).

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 is exercised if propane prices fall below the strike price of $0.5650 per gallon in December 2016, January 2017, and February 2017. If exercised, we will receive the difference between the market price and the strike price during those months. We accounted for the put option as a fair value hedge, and there is no ineffective portion of this hedge. As of December 31, 2016, the put option had a fair value of $9,000. The change in fair value of the put option effectively reduced our propane inventory balance.

In January 2016, PESCO entered into a SCO 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 SCO supplier agreement, which terminates on March 31, 2017.

In conjunction with the SCO 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. The contracts expire by March 31, 2017. We had 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 de-designated the hedges as they were no longer deemed to be highly effective. We are now accounting for them as derivatives on a mark-to-market basis, with the change in fair value reflected as unrealized gain (loss) in current period earnings, and these are no longer offset by any associated gain (loss) in the value of the inventory previously hedged. As of December 31, 2016, we had a total of 1.3 million Dts in natural gas futures contracts with a mark-to-market liability of $773,000.

Beginning in October 2015, PESCO entered into natural gas futures contracts associated with the purchase and sale of natural gas to other specific customers. These contracts expire within two years, and we have accounted for them as cash flow hedges. There is no ineffective portion of these hedges. At December 31, 2016, PESCO had a total of 3.7 million Dts hedged under natural gas futures contracts, with an asset fair value of approximately $113,000. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss).

Fair Value Hedges

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 2015 or 2014.

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 market.

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.

Hedging Activities in 2014

In August and October 2014, Sharp entered into call options to protect against an increase in propane prices associated with 1.3 million gallons purchased at market-based prices to supply the demands of our propane price cap program customers. The retail price that we charged those customers during the heating season was capped at a pre-determined level. We would have exercised the call options if the propane prices had risen above the strike price of $1.0875 per gallon in December 2014 through February of 2015, and $1.0650 per gallon in January through March 2015. We paid $98,000 to purchase the call options, which expired without exercise as the market prices were below the strike prices. We accounted for the call options as cash flow hedges.

In May 2014, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons purchased in December 2014 through February 2015. Under these swap agreements, Sharp would have received the difference between the index prices (Mont Belvieu prices in December 2014 through February 2015) and the swap prices of $1.1350, $1.0975 and $1.0475 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 630,000 gallons purchased during this period. We had initially accounted for them as cash flow hedges as the swap agreements met all the requirements. We paid $1.1 million, representing the difference between the market prices and strike prices during the months of December 2014 through February 2015. At December 31, 2015, we elected to discontinue hedge accounting on the swap agreements and reclassified $735,000 of unrealized loss from other comprehensive loss to propane cost of sales. Subsequently, we accounted for them as derivative instruments on a mark-to-market basis with the change in fair value reflected in current period earnings.

In May 2014, Sharp entered into put options to protect against declines in propane prices and related potential inventory losses associated with 630,000 gallons purchased for the propane price cap program in December 2014 through February 2015. We exercised the put options because propane prices fell below the strike prices of $1.0350, $0.9975 and $0.9475 per gallon, for each option agreement in December 2014 through February 2015, respectively. We paid $128,000 to purchase the put options and received $868,000 from the exercise of the options, representing the difference between the market prices and strike prices during those months. We accounted for them as fair value hedges.

Commodity Contracts for Trading Activities

Xeron engages in trading activities using forward and futures contracts for propane and crude oil. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under this method, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statements of income for the period of change. As of December 31, 2016 and 2015, Xeron had no outstanding contracts that were accounted for as derivatives.

Xeron entered into master netting agreements with two counterparties to mitigate exposure to counterparty credit risk. The master netting agreements enable Xeron to net these two counterparties' outstanding accounts receivable and payable, which are presented on a gross basis in the accompanying consolidated balance sheets. At December 31, 2016, Xeron had no accounts receivable or accounts payable balances to offset with these two counterparties. At December 31, 2015, Xeron had a right to offset $431,000 of accounts payable, but did not have outstanding accounts receivable, with these two counterparties.

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, 2016 and 2015, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	**Balance Sheet Location**	**December 31, 2016**	**December 31, 2015**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	**$ —**	$ 1
Propane swap agreements	Mark-to-market energy assets	**8**	—
Derivatives designated as fair value hedges			
Put options	Mark-to-market energy assets	**9**	152
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Mark-to-market energy assets	**113**	—
Propane swap agreements	Mark-to-market energy assets	**693**	—
Total asset derivatives		**$ 823**	$ 153

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	**Balance Sheet Location**	**December 31, 2016**	**December 31, 2015**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ —**	$ 1
Natural gas futures contracts	Mark-to-market energy liabilities	**773**	—
Derivatives designated as cash flow hedges			
Propane swap agreements	Mark-to-market energy liabilities	**—**	323
Natural gas futures contracts	Mark-to-market energy liabilities	**—**	109
Total liability derivatives		**$ 773**	$ 433

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	2016	2015	2014
Derivatives not designated as hedging instruments:				
Realized (loss) gain on forward contracts and options [1]	Revenue	**$ (546)**	$ 426	$ 1,423
Unrealized (loss) gain on forward contracts [1]	Revenue	**—**	(126)	57
Natural gas futures contracts	Cost of sales	**(541)**	—	—
Propane swap agreements	Cost of sales	**7**	18	(735)
Derivatives designated as fair value hedges:				
Put/Call option	Cost of Sales	**49**	528	235
Put/Call option [2]	Propane Inventory	**—**	43	517
Natural gas futures contracts	Natural Gas Inventory	**(233)**	—	—
Derivatives designated as cash flow hedges				
Propane swap agreements	Cost of Sales	**(364)**	(120)	(341)
Propane swap agreements	Other Comprehensive Income	**1,016**	(323)	—
Call options	Cost of Sales	**—**	(81)	(17)
Call options	Other Comprehensive Income	**—**	—	(55)
Natural gas futures contracts	Cost of sales	**345**	—	—
Natural gas futures contracts	Other Comprehensive Income	**222**	109	—
Total		**$ (45)**	$ 474	$ 1,084

(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.

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, 2016 and 2015, respectively:

		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**	**$ —**	**$ —**
Mark-to-market energy assets, including put options	**$ 823**	**$ —**	**$ 823**	**$ —**
Liabilities:				
Mark-to-market energy liabilities, including swap agreements and natural gas futures contracts	**$ 773**	**$ —**	**$ 773**	**$ —**

		Fair Value Measurements Using:		
As of December 31, 2015	**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	$ 18	$ 18	$ —	$ —
Investments—guaranteed income fund	$ 279	$ —	$ —	$ 279
Investments—mutual funds and other	$ 3,347	$ 3,347	$ —	$ —
Mark-to-market energy assets, including put options	$ 153	$ —	$ 153	$ —
Liabilities:				
Mark-to-market energy liabilities, including swap agreements and natural gas futures contracts	$ 433	$ —	$ 433	$ —

The following valuation techniques were used to measure fair value assets on a recurring basis as of December 31, 2016 and 2015:

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:

Mark-to-market energy assets and liabilities — These forward contracts are valued using market transactions in either the listed or OTC markets.

Propane put/call options, swap agreements and natural gas futures contracts — 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.

Investments measured at net asset value — The fair value is based on net asset value per unit of investments, which uses significant observable inputs. However, these investments were not traded publicly and did not have quoted market prices in active 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, 2016 and 2015:

	For the Year Ended December 31,	
	2016	**2015**
(in thousands)		
Beginning Balance	**$ 279**	$ 287
Purchases and adjustments	**123**	69
Transfers/disbursements	**151**	(82)
Investment income	**8**	5
Ending Balance	**$ 561**	$ 279

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

At December 31, 2016 and 2015, 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, 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 a fair value of $161.5 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, 2015, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of $153.7 million compared to the estimated fair value of $165.1 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, 2016 and 2015, consisted of the following:

(in thousands)	December 31, 2016	December 31, 2015
Rabbi trust (associated with the Non-qualified Deferred Compensation Plan)	**$ 4,881**	$ 3,626
Investments in equity securities	**21**	18
Total	**$ 4,902**	$ 3,644

We classify these investments as trading securities and report them at their fair value. For the years ended December 31, 2016, 2015 and 2014, we recorded net unrealized gains of $379,000, $7,000 and $237,000, 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 month 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, 2016 and 2015 was as follows:

	As of December 31,	
(in thousands)	2016	2015
Regulated Energy	**$ 3,353**	$ 3,353
Unregulated Energy	**11,717**	11,195
Total	**$ 15,070**	$ 14,548

As of December 31, 2016, 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, 2016, goodwill in our Unregulated Energy segment is comprised of $10.1 million from the acquisition of Gatherco in April 2015 and $1.6 million from the acquisition of the operating assets of several companies. The annual impairment testing for 2016 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2016 and 2015 are as follows:

	As of December 31,			
	2016		2015	
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Customer lists	**$ 4,012**	**$ 2,379**	$ 4,012	$ 2,048
Non-Compete agreements	**270**	**146**	270	103
Other	**270**	**184**	270	179
Total	**$ 4,552**	**$ 2,709**	$ 4,552	$ 2,330

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, 2016, 2015 and 2014, amortization expense of intangible assets was $380,000, $367,000, and $396,000, respectively. Amortization expense of intangible assets is expected to be $366,000 for 2017, $353,000 for 2018, $353,000 for 2019, $353,000 for 2020 and $288,000 for 2021.

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 2012 are subject to examination.

We had a net operating loss for federal income tax purposes as of December 31, 2016 of $14.0 million which we will carry back two years and none as of December 31, 2015. We had state net operating losses of $19.6 million and $25.7 million and in various states as of December 31, 2016 and 2015, respectively, and almost all of these will expire in 2034. We have recorded a deferred tax asset of $893,000 and $884,000 related to state net operating loss carry-forwards at December 31, 2016 and 2015, respectively, but 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.

The following tables provide: (a) the components of income tax expense in 2016, 2015, and 2014; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2016, 2015, and 2014; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2016 and 2015.

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Current Income Tax Expense			
Federal	**$ (4,898)**	$ 4,875	$ 434
State	**2,053**	1,533	1,311
Other	**(71)**	(23)	(35)
Total current income tax expense	**(2,916)**	6,385	1,710
Deferred Income Tax Expense [(1)]			
Property, plant and equipment	**31,062**	21,205	20,382
Deferred gas costs	**1,163**	(1,539)	1,614
Pensions and other employee benefits	**237**	(84)	537
FPU merger related premium cost and deferred gain	**(572)**	(556)	(802)
Net operating loss carryforwards	**(9)**	2,078	(112)
Other	**(624)**	(584)	616
Total deferred income tax expense	**31,257**	20,520	22,235
Total Income Tax Expense	**$ 28,341**	$ 26,905	$ 23,945

(1)Includes $2.1 million, $2.1 million and $2.6 million of deferred state income taxes for the years 2016, 2015 and 2014, respectively.

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Reconciliation of Effective Income Tax Rates			
Continuing Operations			
Federal income tax expense [(1)]	**$ 22,759**	$ 23,865	$ 21,121
State income taxes, net of federal benefit	**3,422**	3,062	2,946
ESOP dividend deduction	**(264)**	(263)	(267)
Other	**2,424**	241	145
Total Income Tax Expense	**$ 28,341**	$ 26,905	$ 23,945
Effective Income Tax Rate	**38.81%**	39.54%	39.88%

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

(in thousands)	As of December 31, 2016	As of December 31, 2015
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	**$ 218,074**	$ 185,448
Acquisition adjustment	**14,840**	15,490
Loss on reacquired debt	**442**	485
Deferred gas costs	**1,846**	683
Other	**6,375**	5,961
Total deferred income tax liabilities	**241,577**	208,067
Deferred income tax assets:		
Pension and other employee benefits	**6,230**	6,570
Environmental costs	**2,592**	2,445
Net operating loss carryforwards	**952**	943
Investment tax credit carryforwards	**2,643**	—
Self insurance	**189**	278
Storm reserve liability	**1,131**	1,153
Other	**4,946**	4,078
Total deferred income tax assets	**18,683**	15,467
Deferred Income Taxes Per Consolidated Balance Sheets	**$ 222,894**	$ 192,600

12. LONG-TERM DEBT

Our outstanding long-term debt is shown below:

(in thousands)	As of December 31, 2016	As of December 31, 2015
FPU secured first mortgage bonds:		
9.08% bond, due June 1, 2022	**$ 7,978**	$ 7,973
Uncollateralized Senior Notes:		
6.64% note, due October 31, 2017	**2,727**	5,455
5.50% note, due October 12, 2020	**8,000**	10,000
5.93% note, due October 31, 2023	**21,000**	24,000
5.68% note, due June 30, 2026	**29,000**	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
Promissory notes	**168**	238
Capital lease obligation	**3,471**	4,824
Less: debt issuance costs	**(291)**	(333)
Total long-term debt	**149,053**	158,157
Less: current maturities	**(12,099)**	(9,151)
Total long-term debt, net of current maturities	**$ 136,954**	$ 149,006

Annual maturities and principal repayments of long-term debt, excluding the capital lease obligation, are as follows: $12,099 for 2017; $9,421 for 2018; $11,245 for 2019; $15,600 for 2020; $13,600 for 2021 and $87,400 thereafter. See Note 14, *Lease Obligations,* for future payments related to the capital lease obligation.

Shelf Agreement

In October 2015, we entered into a Shelf Agreement with Prudential. Under the terms of the Shelf Agreement, we may request that Prudential purchase, through October 2018, up to $150.0 million of our Shelf Notes at a fixed interest rate and with a maturity date not to exceed twenty years from the date of issuance. Prudential is under no obligation to purchase any of the Shelf Notes. The interest rate and terms of payment of any series of Shelf Notes will be determined at the time of purchase. We currently anticipate the proceeds from the sale of any series of Shelf Notes will be used for general corporate purposes, including refinancing of short-term borrowing and/or repayment of outstanding indebtedness and financing capital expenditures on future projects; however, actual use of such proceeds will be determined at the time of a purchase and each request for purchase with respect to a series of Shelf Notes will specify the exact use of the proceeds.

The Shelf Agreement sets forth certain business covenants to which we are subject when any Shelf Note is outstanding, including covenants that limit or restrict us and our subsidiaries from incurring indebtedness and incurring liens and encumbrances on any of our property.

In May 2016, we submitted a request that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement, which was accepted and confirmed by Prudential. The proceeds received from the issuances of the Shelf Notes will be used to reduce short-term borrowings under our revolving credit facility, lines of credit and/or to fund capital expenditures. The closing of the sale and issuance of the Shelf Notes is expected to occur on or before April 28, 2017.

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, 2016, FPU’s cumulative net income base was $128.5 million, offset by restricted payments of $37.6 million, leaving $90.9 million of cumulative net income for FPU free of restrictions pursuant to this covenant.

The dividend restrictions by FPU’s first mortgage bonds resulted in approximately $45.0 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2016. This represents approximately 10 percent of our consolidated net assets. Other than the dividend restrictions by 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 Chesapeake Utilities' 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 6.64 percent, 5.50 percent and 5.93 percent Senior Notes, due October 31, 2017, October 12, 2020 and October 31, 2023, respectively. 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, 2016, the cumulative consolidated net income base was $329.4 million, offset by restricted payments of $157.1 million, leaving $172.3 million of cumulative net income free of restrictions.

As of December 31, 2016, we are in compliance with all of our debt covenants.

13. Short-term Borrowings

At December 31, 2016 and 2015, we had $209.9 million and $173.4 million, respectively, of short-term borrowings outstanding. In October 2015, we entered into a Credit Agreement with the Lenders for a $150.0 million Revolver for a term of five years subject to the terms and conditions as specified. We now have an aggregate of $320.0 million in available credit lines: four unsecured bank credit facilities with three financial institutions with $170.0 million in total available credit and a Revolver with five participating Lenders totaling $150.0 million. The annual weighted average interest rates on our short-term borrowings were 1.43 percent and 1.30 percent for 2016 and 2015, respectively. We incurred commitment fees of $145,000 and $106,000 in 2016 and 2015, respectively.

(in thousands)	Total Facility	Interest Rate	Expiration Date	Outstanding borrowings at December 31, 2016	Outstanding borrowings at December 31, 2015	Available at December 31, 2016
Bank Credit Facility						
Committed revolving credit facility A	$ 55,000	LIBOR plus 1.00 percent (1)	October 29, 2017	$ 45,000	$ 30,000	$ 10,000
Committed revolving credit facility B	30,000	LIBOR plus 1.00 percent (1)	October 31, 2017	21,311	23,757	8,689
Short-term revolving credit Note C	50,000	LIBOR plus 0.80 percent (2)	October 31, 2017	50,000	50,000	—
Committed revolving credit facility D	35,000	LIBOR plus 0.85 percent (3)	December 19, 2017	35,000	30,000	—
Committed revolving credit facility E	150,000	LIBOR plus 1.00 percent (1)	October 8, 2020	50,000	35,000	100,000
Total short term credit facilities	$ 320,000			$ 201,311	$ 168,757	$ 118,689
Book overdrafts(4)				8,560	4,640	
Total short-term borrowing				$ 209,871	$ 173,397	

(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.

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.

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 2016, 2015 and 2014 was $2.5 million, $1.7 million and $1.8 million, respectively. Future minimum payments under our current lease agreements for the years 2017 through 2021 are $1.4 million, $1.1 million, $848,000, $688,000, and $462,000, respectively, and approximately $2.3 million thereafter, with an aggregate total of approximately $6.8 million.

For each of the years ended December 31, 2016 and 2015, we paid $1.5 million and for the year ended December 31, 2014, we paid $1.1 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 per year for both 2017 and 2018 and $625,000 in 2019, with an aggregate total of $3.6 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, 2016 and 2015. 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

Our Board of Directors has adopted a Rights Plan by declaring a dividend of one preferred stock purchase right (each, a "Right," and, collectively, the "Rights") for each outstanding share of our common stock held of record on September 3, 1999, as adjusted for our stock split in September of 2014, and for additional shares of common stock issued since that time. Unless exercised, the Rights trade with our common stock and are evidenced by the common stock certificate. In general, each Right will become exercisable and trade independently from our common stock upon a person or entity acquiring a beneficial ownership of 15 percent or more of our outstanding common stock.

Each Right, if it becomes exercisable, initially entitles 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) will 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. The Rights expire on August 20, 2019 unless they are redeemed earlier by us at the redemption price of $0.01 per Right. We may redeem the Rights at any time before they become exercisable and thereafter only in limited circumstances.

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 contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss). The following table presents the changes in the balance of accumulated other comprehensive loss for the years ended December 31, 2016 and 2015. All amounts in the following table are presented net of tax.

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

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2014	$ (5,643)	$ (33)	$ (5,676)
Other comprehensive loss before reclassifications	(286)	(350)	(636)
Amounts reclassified from accumulated other comprehensive loss	349	123	472
Net current-period other comprehensive income/(loss)	63	(227)	(164)
As of December 31, 2015	$ (5,580)	$ (260)	$ (5,840)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the years ended December 31, 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)	**2016**	**2015**
Amortization of defined benefit pension and postretirement plan items:		
Prior service cost [(1)]	**$ 77**	$ 68
Net gain [(1)]	**(871)**	(650)
Total before income taxes	**(794)**	(582)
Income tax benefit	**320**	233
Net of tax	**$ (474)**	$ (349)
Gains and losses on commodity contracts cash flow hedges		
Propane swap agreements [(2)]	**$ (322)**	$ (120)
Call options [(2)]	**—**	(55)
Natural gas futures [(2)]	**345**	(31)
Total before income taxes	**23**	(206)
Income tax impact	**(3)**	83
Net of tax	**$ 20**	$ (123)
Total reclassifications for the period	**$ (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 $2.7 million at December 31, 2016 and 2015, 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 $20.6 million and $22.2 million at December 31, 2016 and 2015, 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 and $2.5 million at December 31, 2016 and 2015, respectively, 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, 2016 and 2015 and the net periodic cost for the years ended December 31, 2016, 2015 and 2014 for the Chesapeake and FPU Pension Plans:

	Chesapeake Pension Plan		FPU Pension Plan	
At December 31,	**2016**	**2015**	**2016**	**2015**
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	**$ 11,501**	$ 11,981	**$ 64,435**	$ 68,173
Interest cost	**421**	407	**2,525**	2,504
Actuarial loss (gain)	**330**	(401)	**(216)**	(3,374)
Effect of settlement	**(433)**	—	**—**	—
Benefits paid	**(464)**	(486)	**(2,912)**	(2,868)
Benefit obligation — end of year	**11,355**	11,501	**63,832**	64,435
Change in plan assets:				
Fair value of plan assets — beginning of year	**8,752**	9,078	**42,207**	45,077
Actual return on plan assets	**424**	(289)	**2,343**	(1,464)
Employer contributions	**389**	449	**1,634**	1,462
Benefits paid	**(464)**	(486)	**(2,912)**	(2,868)
Effect of settlement	**(433)**	—	**—**	—
Fair value of plan assets — end of year	**8,668**	8,752	**43,272**	42,207
Reconciliation:				
Funded status	**(2,687)**	(2,749)	**(20,560)**	(22,228)
Accrued pension cost	**$ (2,687)**	$ (2,749)	**$ (20,560)**	$ (22,228)
Assumptions:				
Discount rate	**3.75%**	3.75%	**4.00%**	4.00%
Expected return on plan assets	**6.00%**	6.00%	**6.50%**	7.00%

	Chesapeake Pension Plan			FPU Pension Plan		
For the Years Ended December 31,	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
(in thousands)						
Components of net periodic pension cost:						
Interest cost	**$ 421**	$ 407	$ 425	**$ 2,525**	$ 2,504	$ 2,613
Expected return on assets	**(501)**	(530)	(516)	**(2,702)**	(3,107)	(3,089)
Amortization of actuarial loss	**459**	392	176	**519**	456	8
Settlement expense	**161**	—	—	**—**	—	—
Net periodic pension cost	**540**	269	85	**342**	(147)	(468)
Amortization of pre-merger regulatory asset	**—**	—	—	**761**	761	761
Total periodic cost	**$ 540**	$ 269	$ 85	**$ 1,103**	$ 614	$ 293
Assumptions:						
Discount rate	**3.75%**	3.50%	4.25%	**4.00%**	3.75%	4.75%
Expected return on plan assets	**6.00%**	6.00%	6.00%	**6.50%**	7.00%	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 by FPU prior to the merger to be recovered through rates pursuant to an order by the Florida PSC. The unamortized balance of this regulatory asset was $2.1 million and $2.8 million at December 31, 2016 and 2015, respectively.

The following sets forth the funded status at December 31, 2016 and 2015 and the net periodic cost for the years ended December 31, 2016, 2015 and 2014 for the Chesapeake SERP:

At December 31, *(in thousands)*	2016	2015
Change in benefit obligation:		
Benefit obligation — beginning of year	**$ 2,510**	$ 2,650
Interest cost	**91**	91
Actuarial gain	**(21)**	(85)
Benefits paid	**(152)**	(146)
Benefit obligation — end of year	**2,428**	2,510
Change in plan assets:		
Fair value of plan assets — beginning of year	**—**	—
Employer contributions	**152**	146
Benefits paid	**(152)**	(146)
Fair value of plan assets — end of year	**—**	—
Reconciliation:		
Funded status	**(2,428)**	(2,510)
Accrued pension cost	**$ (2,428)**	$ (2,510)
Assumptions:		
Discount rate	**3.75%**	3.75%

For the Years Ended December 31, *(in thousands)*	2016	2015	2014
Components of net periodic pension cost:			
Interest cost	**$ 91**	$ 91	$ 92
Amortization of prior service cost	**—**	9	19
Amortization of actuarial loss	**87**	99	47
Net periodic pension cost	**$ 178**	$ 199	$ 158
Assumptions:			
Discount rate	**3.75%**	3.50%	4.25%

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, 2016, 2015 and 2014:

	Chesapeake Pension Plan			FPU Pension Plan		
At December 31,	2016	2015	2014	2016	2015	2014
Asset Category						
Equity securities	**52.93%**	48.01%	51.42%	**53.18%**	48.56%	52.62%
Debt securities	**37.64%**	39.62%	37.31%	**37.74%**	41.74%	37.69%
Other	**9.43%**	12.37%	11.27%	**9.08%**	9.70%	9.69%
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, 2016 and 2015, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

Fair Value Measurement Hierarchy

	December 31, 2016				December 31, 2015			
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)	**$ 4,031**	**$ —**	**$ —**	**$ 4,031**	$ 3,641	$ —	$ —	$ 3,641
U.S. Mid Cap (1)	**1,677**	**—**	**—**	**1,677**	1,577	—	—	1,577
U.S. Small Cap (1)	**845**	**—**	**—**	**845**	865	—	—	865
International (2)	**9,574**	**—**	**—**	**9,574**	9,416	—	—	9,416
Alternative Strategies (3)	**5,238**	**—**	**—**	**5,238**	2,737	—	—	2,737
	21,365	**—**	**—**	**21,365**	18,236	—	—	18,236
Mutual Funds - Debt securities								
Fixed income (4)	**16,958**	**—**	**—**	**16,958**	18,565	—	—	18,565
High Yield (4)	**2,636**	**—**	**—**	**2,636**	2,521	—	—	2,521
	19,594	**—**	**—**	**19,594**	21,086	—	—	21,086
Mutual Funds - Other								
Commodities (5)	**2,134**	**—**	**—**	**2,134**	1,365	—	—	1,365
Real Estate (6)	**2,116**	**—**	**—**	**2,116**	2,529	—	—	2,529
Guaranteed deposit (7)	**—**	**—**	**498**	**498**	—	—	1,286	1,286
	4,250	**—**	**498**	**4,748**	3,894	—	1,286	5,180
Total Pension Plan Assets in fair value hierarchy	**$45,209**	**$ —**	**$ 498**	**45,707**	$43,216	$ —	$ 1,286	44,502
Investments measured at net asset value (8)				**6,233**				6,457
Total Pension Plan Assets				**$ 51,940**				$ 50,959

(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, 2016 and 2015, 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 underlining 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, 2016 and 2015:

	For the Year Ended December 31,	
(in thousands)	**2016**	**2015**
Balance, beginning of year	**$ 1,286**	$ 1,144
Purchases	**2,023**	1,926
Transfers in	**1,435**	1,900
Disbursements	**(4,268)**	(3,688)
Investment income	**22**	4
Balance, end of year	**$ 498**	$ 1,286

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, 2016 and 2015 and the net periodic cost for the years ended December 31, 2016, 2015, and 2014:

	Chesapeake Postretirement Plan		FPU Medical Plan	
At December 31,	**2016**	**2015**	**2016**	**2015**
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	**$ 1,153**	$ 1,238	**$ 1,444**	$ 1,712
Interest cost	**43**	42	**55**	57
Plan participants contributions	**90**	108	**64**	75
Actuarial loss (gain)	**20**	(58)	**(41)**	(132)
Benefits paid	**(174)**	(177)	**(173)**	(268)
Benefit obligation — end of year	**1,132**	1,153	**1,349**	1,444
Change in plan assets:				
Fair value of plan assets — beginning of year	**—**	—	**—**	—
Employer contributions(1)	**84**	69	**109**	193
Plan participants contributions	**90**	108	**64**	75
Benefits paid	**(174)**	(177)	**(173)**	(268)
Fair value of plan assets — end of year	**—**	—	**—**	—
Reconciliation:				
Funded status	**(1,132)**	(1,153)	**(1,349)**	(1,444)
Accrued postretirement cost	**$ (1,132)**	$ (1,153)	**$ (1,349)**	$ (1,444)
Assumptions:				
Discount rate	**3.75%**	3.75%	**4.00%**	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 2016, 2015, and 2014 include the following components:

	Chesapeake Postretirement Plan			FPU Medical Plan		
For the Years Ended December 31,	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
(in thousands)						
Components of net periodic postretirement cost:						
Interest cost	**$ 43**	$ 42	$ 39	**$ 55**	$ 57	$ 69
Amortization of:						
Actuarial loss	**64**	72	55	**—**	—	—
Prior service cost	**(77)**	(77)	(77)	**—**	—	—
Net periodic cost	**30**	37	17	**55**	57	69
Amortization of pre-merger regulatory asset	**—**	—	—	**8**	8	8
Net periodic cost	**$ 30**	$ 37	$ 17	**$ 63**	$ 65	$ 77
Assumptions						
Discount rate	**3.75%**	3.50%	4.25%	**4.00%**	3.75%	4.75%

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 $30,000 and $38,000 at December 31, 2016 and 2015, 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, 2016:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ —	$ —	$ —	$ (678)	$ —	$ (678)
Net loss	4,223	20,043	757	748	58	25,829
Total	$ 4,223	$ 20,043	$ 757	$ 70	$ 58	$ 25,151
Accumulated other comprehensive loss pre-tax(1)	$ 4,223	$ 3,808	$ 757	$ 70	$ 11	$ 8,869
Post-merger regulatory asset	—	16,235	—	—	47	16,282
Subtotal	4,223	20,043	757	70	58	25,151
Pre-merger regulatory asset	—	2,065	—	—	30	2,095
Total unrecognized cost	$ 4,223	$ 22,108	$ 757	$ 70	$ 88	$ 27,246

(1) The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2016 is net of income tax benefits of $3.5 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 2017 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	$ 426	$ 523	$ 87	$ 65	$ —	$ 1,101
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 2016, 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 2016 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 $321,000 as of December 31, 2016, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2016 by approximately $12,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $257,000 as of December 31, 2016, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2016 by approximately $10,000.

Estimated Future Benefit Payments

In 2017, we expect to contribute $323,000 and $2.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $151,000 to the Chesapeake SERP. We also expect to contribute $83,000 and $129,000 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)
2017	$ 746	$ 3,041	$ 151	$ 83	$ 129
2018	$ 664	$ 3,128	$ 150	$ 82	$ 93
2019	$ 713	$ 3,235	$ 149	$ 82	$ 99
2020	$ 649	$ 3,319	$ 148	$ 76	$ 93
2021	$ 902	$ 3,370	$ 376	$ 72	$ 95
Years 2022 through 2026	$ 5,020	$ 18,447	$ 732	$ 319	$ 405

(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, 2016, 2015 and 2014, we sponsored a 401(k) Retirement Savings Plan. This Plan is offered to all eligible employees who have completed 3 months of service, except for employees represented by a collective bargaining agreement that does not specifically provide for participation in the plan, non-resident aliens with no U.S. source income and individuals classified as consultants, independent contractors or leased employees. 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. Employees with one year of service are 20 percent vested and will become 100 percent vested after two years of service. Employees who do not make an election to contribute or 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. All contributions and matched funds can be invested among the mutual funds available for investment.

Employer contributions to our retirement savings plan totaled $4.5 million for the year ended December 31, 2016, and $4.1 million for the years ended December 31, 2015 and 2014, respectively. As of December 31, 2016, 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, after the election is made, in the form of a 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 401(k) 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 $4.9 million and $3.6 million at December 31, 2016 and 2015, 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' retainers and fees 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 $2.4 million and $1.9 million at December 31, 2016 and 2015, 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 539,374 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, 2016, 2015 and 2014:

	For the Year Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Awards to non-employee directors	**$ 580**	$ 640	$ 540
Awards to key employees	**1,787**	1,297	1,418
Total compensation expense	**2,367**	1,937	1,958
Less: tax benefit	**(952)**	(780)	(790)
Share-based compensation amounts included in net income	**$ 1,415**	$ 1,157	$ 1,168

Stock Options

We did not have any stock options outstanding at December 31, 2016 or 2015, nor were any stock options issued during the years 2014 through 2016.

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 2016, each of our non-employee directors received an annual retainer of 953 shares of common stock under the SICP for board service through the 2017 Annual Meeting of Stockholders. A summary of stock activity for our non-employee directors for the years ended December 31, 2016 and 2015 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding — December 31, 2014	—	$ —
Granted	14,484	$ 45.54
Vested	(14,484)	$ 45.54
Outstanding — December 31, 2015	—	$ —
Granted	8,577	$ 62.90
Vested	(8,577)	$ 62.90
Outstanding — December 31, 2016	—	$ —

The weighted average grant date fair value of shares granted to our non-employee directors during 2016, 2015 and 2014 was $62.90, $45.54 and $41.60 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, 2016, there was $180,000 of unrecognized compensation expense related to these awards. This expense will be fully recognized by April 2017, 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, 2014	123,038	$ 32.60
Granted	33,719	$ 47.65
Vested	(43,839)	$ 28.01
Expired	(2,520)	$ 28.83
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

In 2016, 2015 and 2014, 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 12,031, 12,620 and 12,687 for 2016, 2015 and 2014, respectively, was based on the value of the shares on their award date, determined by the average of the high and low prices of our common stock. Total payments for the employees' tax obligations to the taxing authorities were approximately $770,000, $592,000 and $503,000, in 2016, 2015 and 2014, respectively. The tax benefits associated with these obligations for 2016, 2015 and 2014 are $285,000, $297,000, and $398,000, respectively, and was recorded in additional paid-in capital in the consolidated statements of stockholders' equity for 2015 and 2014. The tax benefit for 2016 is 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 2016, 2015 and 2014 was $67.90, $47.65 and $39.99 per share, respectively. The intrinsic value of these awards was $7.7 million, $6.3 million and $6.1 million in 2016, 2015 and 2014, respectively. At December 31, 2016, there was $2.2 million of unrecognized compensation cost related to these awards, which is expected to be recognized during 2017 through 2018.

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 natural gas distribution 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 include an annual increase of $2.25 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 $2.25 million have been accrued for refund as of December 31, 2016 and will be distributed to ratepayers beginning in the first quarter of 2017. We recognized incremental revenue of approximately $1.5 million ($897,000 net of tax) in 2016.

Maryland

Sandpiper Rate Case Filing: In May 2013, the Maryland PSC approved our application to acquire ESG operating assets and the transfer of the ESG franchise to Sandpiper. As part of this application, the Maryland PSC directed that Sandpiper file a base rate proceeding within two years, six months. As a result, in December 2015, Sandpiper filed an application with the Maryland PSC for a base rate increase and certain other changes to its tariff. The parties reached a settlement agreement, which Sandpiper filed with the Maryland PSC in August 2016. 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. A revenue normalization mechanism and stratification of rate classes were also included in the settlement agreement. The order became final in October 2016 with the new rates effective December 1, 2016.

Florida

In September 2015, FPU's electric division filed to recover the cost of the proposed Florida Power & Light Company interconnect project through FPU's annual Fuel and Purchased Power Cost Recovery Clause filing. The interconnect project will enable FPU's electric division to negotiate a new power purchase agreement that will mitigate fuel costs for its Northeast division. This action was approved by the Florida PSC at its Agenda Conference held in December 2015. In January 2016, the Office of Public Counsel filed an appeal of the Florida PSC's decision with the Florida Supreme Court. Legal briefs were filed by the Florida PSC, FPU, and the Office of Public Counsel and oral arguments were heard by the Florida Supreme Court in November 2016. To date, the Court has not issued a decision.

In February 2016, FPU's natural gas division filed a petition with the Florida PSC for approval of an amendment to its existing transportation agreement with the City of Lake Worth, located in Palm Beach County, Florida. The amendment allows the city to resell natural gas distributed by FPU to the city's compressed natural gas station. The city will then resell the natural gas, after compression, to its customers. The amendment to the transportation agreement was approved by the Florida PSC at its Agenda Conference held in April 2016.

In April 2016, FPU's natural gas divisions and Chesapeake Utilities' Florida division filed a joint petition for approval to allow FPU and Chesapeake Utilities to expand the cost allocation of the intrastate and unreleased capacity-related components currently embedded in the purchased gas adjustment and operational balancing account, which is currently allocated to a limited number of customers. The expanded allocation of these costs includes additional customers, primarily transportation customers, benefiting from these costs but not currently paying for them. This petition was approved by the Florida PSC at its Agenda Conference in September 2016.

In July 2016, Chesapeake Utilities' Florida division filed for approval of the final environmental true-up relating to expected future remediation costs at our former MGP site in Winter Haven, Florida. This petition was approved by the Florida PSC in December 2016.

In February, 2017, FPU's electric division filed a petition with the Florida PSC, requesting a temporary surcharge mechanism to recover costs, inclusive of an appropriate return on investment, associated with an essential reliability and modernization project on its electric distribution system. We are seeking approval to invest approximately $59.8 million, over a five-year period associated with this project. In February, 2017, the Office of Public Counsel intervened in this petition. The outcome of our petition is not known at this time.

Eastern Shore

White Oak Mainline Expansion Project: In November 2014, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate certain expansion facilities designed to provide 45,000 Dts/d of firm transportation service to an industrial customer in Kent County, Delaware. Eastern Shore proposed to construct approximately 7.2 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and 3,550 horsepower of additional compression at Eastern Shore's existing Delaware City Compressor Station in New Castle County, Delaware.

In November 2015, Eastern Shore filed an amendment to this application, which indicated the preferred pipeline route and shortened the total miles of the proposed pipeline to 5.4 miles.

In July 2016, the FERC authorized Eastern Shore to construct and operate the proposed White Oak Mainline Project. The FERC denied Eastern Shore's request for a pre-determination of rolled-in rate treatment in the certificate proceeding. However, FERC's determination is without prejudice to Eastern Shore filing rolled-in rate treatment of these project facilities in a future general rate case. The certificate required Eastern Shore to comply with 19 environmental conditions.

In July 2016, Eastern Shore accepted the certificate of public convenience and necessity and, in August 2016, filed its Implementation Plan to comply with each environmental condition and to request approval to begin construction. In August 2016, the FERC issued a "Notice to Proceed," and Eastern Shore commenced construction during August 2016.

In December 2016, Eastern Shore filed a request to place the pipeline looping located in Chester County, Pennsylvania into service. The FERC granted approval to place the Daleville and Kemblesville Loops into operation in December 2016. Construction is continuing on the remaining component of the project, the Delaware City Compressor Station, which is expected to be completed and in service in March 2017. The entire project, when completed, is expected to cost $39.8 million. Eastern Shore continues to file weekly status reports with the FERC in compliance with the environmental conditions.

System Reliability Project: In May 2015, Eastern Shore submitted an application to the FERC seeking authorization 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. Since the project is intended to improve system reliability, Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project. In July 2016, the FERC ordered that Eastern Shore's request for a determination of rolled-in rate treatment may be addressed in its next rate base proceeding and required Eastern Shore to comply with 19 environmental conditions.

In September 2016, the FERC granted approval to start construction on all phases of the project. Construction commenced on the Bridgeville Compressor Station and the Porter Road Loop in August 2016 and on the Dover Loop in September 2016.

In December 2016, Eastern Shore filed a request to place the pipeline looping located in New Castle County, Delaware into service. The FERC granted approval to place the Porter Road Loop into service in December 2016. The remaining components of the project, the Bridgeville Compressor Station and the Dover Loop, are anticipated to be completed by the end of April 2017. Eastern Shore continues to file weekly status reports with the FERC in compliance with the environmental conditions. The estimated cost of the project is $36.0 million.

*2017 Expansion Project: I*n May 2016, Eastern Shore submitted a request to the FERC to initiate the FERC's pre-filing review procedures for Eastern Shore's 2017 expansion project. The expansion project's facilities include approximately23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional 3,550 horsepower 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. In May 2016, the FERC approved Eastern Shore's request to commence the pre-filing review process. Eastern Shore entered into Precedent Agreements with four existing customers as well as Chesapeake affiliates, 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 certificate of public convenience and necessity seeking authorization to construct the expansion facilities. Interventions or comments were accepted through February 1, 2017. Six of Eastern Shore's existing customers have intervened to become parties to the docket, and comments have been submitted by two landowners. FERC has issued two sets of data requests to assist in its evaluation of the project. Eastern Shore submitted responses to both data request sets on February 14, 2017. Upon receipt and evaluation of the environmental-related responses, FERC will be able to establish a schedule for completing its environmental assessment on the project. The estimated cost of this expansion project is $98.6 million.

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 are based on the mainline cost of service of approximately $60 million resulting in an overall revenue increase of approximately $18.9 million and a rate of return on common equity of 13.75 percent. In addition to the mainline cost of service, the filing includes incremental rates for the White Oak Mainline Expansion and Lateral projects. Eastern Shore is also proposing to revise its depreciation rates and negative salvage rate based on the results of independent, third party depreciation and negative salvage value studies. The FERC issued a notice of the filing in January 2017, and the comment period ended in February 2017. Fourteen parties intervened in the proceeding with six of those parties filing protests. New rates are proposed to be effective on March 1, 2017, however, the FERC typically suspends the rates for a period of five months. At the end of the suspension period, Eastern Shore will file a motion to implement new rates, subject to refund, effective August 1, 2017.

At December 31, 2016 and 2015, the 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)	**2016**	**2015**
Regulatory Assets		
Under-recovered purchased fuel and conservation cost recovery [1]	**$ 5,703**	$ 4,598
Under-recovered GRIP revenue [2]	**1,469**	3,091
Deferred postretirement benefits [3]	**18,379**	19,479
Deferred conversion and development costs [1]	**8,051**	5,729
Environmental regulatory assets and expenditures [4]	**3,694**	4,158
Acquisition adjustment [5]	**41,864**	43,735
Loss on reacquired debt [6]	**1,145**	1,259
Other	**4,192**	3,738
Total Regulatory Assets	**$ 84,497**	$ 85,787
Regulatory Liabilities		
Self-insurance [7]	**$ 987**	$ 1,031
Over-recovered purchased fuel and conservation cost recovery [1]	**808**	6,994
Storm reserve [7]	**2,310**	2,973
Accrued asset removal cost [8]	**39,826**	39,206
Other	**424**	225
Total Regulatory Liabilities	**$ 44,355**	$ 50,429

(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's 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.

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, 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, 2016, we had accrued approximately $9.8 million in environmental liabilities related to all of 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 all of its MGP sites. Approximately $10.6 million of this amount has been recovered as of December 31, 2016, leaving approximately $3.4 million in regulatory assets for future recovery of environmental costs from FPU's customers.

Environmental liabilities for all of 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.

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated a MGP. FPU is implementing a remedial plan approved by the FDEP for the east parcel of the West Palm Beach site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. On January 12, 2016, FDEP conducted a facility inspection and found no problems or deficiencies.

We expect that similar remedial actions will ultimately be implemented for other portions of the site. Estimated costs of remediation for the West Palm Beach site range from approximately $4.5 million to $15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP at this site. In January 2007, FPU and the Sanford Group signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. 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. As of December 31, 2016, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

In December 2014, the EPA issued a preliminary close-out report, documenting the completion of all physical remedial construction activities at the Sanford site. Groundwater monitoring and statutory five-year reviews to ensure performance of the approved remedy will continue on this site. The total cost of the final remedy is estimated to be over $20.0 million, which includes long-term monitoring and the settlement of claims asserted by two adjacent property owners to resolve damages that the property owners allege they have incurred and will incur as a result of the implementation of the EPA-approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed and paid by FPU in the Third Participation Agreement. The Sanford Group has not requested that FPU contribute to costs beyond the originally agreed upon $650,000 contribution.

As of December 31, 2016, FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be $24,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU's asserted defense to liability for costs exceeding $13.0 million to implement the final remedy for this site, as provided in the Third Participation Agreement, or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of December 31, 2016.

Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a consent order entered into with FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. Groundwater monitoring results have shown a continuing reduction in contaminant concentrations from the sparging system, which has been in operation since 2002. On September 12, 2014, FDEP issued a letter approving shutdown of the sparging operations on the northern portion of the site, contingent upon continued semi-annual monitoring.

Groundwater monitoring results on the southern portion of this site indicated that natural attenuation default criteria continue to be exceeded. Plans to modify the monitoring network on the southern portion of the site in order to collect additional data to support the development of a remedial plan were specified in a letter sent to FDEP in October 2014. The well installation and abandonment program was implemented in October 2014, and documentation was reported in the next semi-annual RAP implementation status report, submitted in January 2015. FDEP approved the plan to expand the bio-sparging operations in the southern portion of the site, and additional sparge points were installed and connected to the operating system in the first quarter of 2016. Groundwater monitoring results from testing conducted in October 2016 indicated that natural attenuation default criteria were met at all wells.

We estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $425,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site.

FDEP previously indicated that we could also be required to remediate sediments along the shoreline of Lake Shipp, immediately west of the site. Based on studies performed to date, and our recent meeting with FDEP, we believe that corrective measures for lake sediments are not warranted and will not be required by FDEP. We therefore have not recorded a liability for sediment remediation.

Seaford, Delaware

In December 2013, the DNREC notified us that it would be conducting a facility evaluation of a former MGP site in Seaford, Delaware. In a report issued in January 2015, DNREC provided the evaluation, which found several compounds within the groundwater and soil that required further investigation. In September 2015, DNREC approved our application to enter this site into the voluntary cleanup program. A remedial investigation was conducted in December 2015, which resulted in DNREC requesting additional investigative work be performed prior to approval of potential remedial actions.

In December 2016, additional on-site wells were installed, developed and sampled pursuant to a September 2016 request from DNREC. The results of the sampling event and proposed future activities are anticipated to be available by the end of the second quarter of 2017. We estimate the cost of potential remedial actions, based on the findings of the DNREC report, to be between $273,000 and $465,000.

Cambridge, Maryland

We are discussing with the MDE a former MGP site located in Cambridge, Maryland. The outcome of this matter cannot be determined at this time; therefore, we have not recorded an environmental liability for this location.

Ohio

We have also completed the investigation, assessment and remediation of eight natural gas pipeline facilities in Ohio that Aspire Energy acquired from Gatherco pursuant to the merger. Under the merger agreement, we are entitled to be indemnified from an escrow fund created at closing for certain matters, including certain claims related to environmental remediation. The costs incurred to date associated with remediation activities for these eight facilities is approximately $1.6 million. In September 2016, we and the Gatherco shareholder agent resolved certain disputes associated with our claims for indemnification, including claims for environmental matters. After deducting the amount of anticipated tax benefits related to our claims and an indemnification deductible in the amount of $431,250 in accordance with the merger agreement, we received approximately $500,000 from the indemnification escrow as final settlement of our claims related to these environmental matters. We do not anticipate submitting any additional environmental claims for indemnification.

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. For our Delaware and Maryland natural gas distribution divisions, we have a contract with an unaffiliated energy marketing and risk management company to manage a portion of their natural gas transportation and storage capacity, which expires on March 31, 2017. Our Delaware and Maryland divisions are currently negotiating a three-year asset management agreement with PESCO and anticipate executing the agreement by the end of the first quarter of 2017. The Delaware PSC has approved PESCO serving as asset manager.

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 3.4 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 3.4 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 natural gas distribution 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 JEA requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU’s electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior nine 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 result in FPU providing an irrevocable letter of credit. As of December 31, 2016, 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. The construction of the CHP plant was completed in June 2016 and 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, it also started selling steam to Rayonier pursuant to a separate 20 -year contract. The CHP plant is powered by natural gas transported by FPU through its distribution system.

The total purchase obligations for natural gas, electric and propane supplies are approximately $90.0 million for 2017, $94.6 million for 2018-2019, $39.5 million for 2020-2021 and $82.2 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 $65 million. In February 2017, our Board of Directors increased this limit to $85 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest of which are for Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that PESCO or Xeron defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at December 31, 2016 was $57.2 million, with the guarantees expiring on various dates through January 2018.

Chesapeake Utilities also guarantees the payment of FPU’s first mortgage bonds. The maximum exposure under the 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).

We issued letters of credit totaling $8.5 million related to the electric transmission services for FPU's northwest electric division, firm transportation service agreement between TETLP and our Delaware and Maryland divisions and to our current and previous primary insurance carriers. These letters of credit have varying expiration dates extending through October 2017. There have been no draws on these letters of credit as of December 31, 2016. 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.

Tax-related Contingencies

We are subject to various audits and reviews by the federal, state and local and other regulatory authorities regarding income taxes and taxes other than income. As of December 31, 2015, we maintained a liability of approximately $50,000 related to unrecognized income tax benefits and $310,000 related to contingencies for taxes other than income. We did not have a liability related to contingencies for taxes other than income and unrecognized income tax benefits at December 31, 2016.

Other

We are involved in certain other legal actions and claims arising in the normal course of business. We are also involved in certain legal and administrative proceedings before various governmental agencies concerning rates. In the opinion of management, the ultimate disposition of these proceedings will not have a material effect on our consolidated financial position, results of operations or cash flows.

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			
(in thousands except per share amounts)	**March 31**	**June 30**	**September 30**	**December 31**
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**
2015 [(1)]				
Operating Revenues	$ 170,081	$ 92,682	$ 91,913	104,567
Operating Income	$ 37,508	$ 13,170	$ 10,909	$ 16,171
Net Income	$ 21,109	$ 6,294	$ 5,119	$ 8,619
Earnings per share:				
Basic	$ 1.45	$ 0.41	$ 0.34	$ 0.56
Diluted	$ 1.44	$ 0.41	$ 0.33	$ 0.56

(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, 2016. 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, 2016.

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, 2016, 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, 2016. In addition, on May 12, 2016, 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, 2016.

Our independent auditors, Baker Tilly Virchow Krause, LLP, have audited and issued their report on effectiveness of our internal control over financial reporting. That report appears on the following page.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation

We have audited Chesapeake Utilities Corporation's (the "Company") internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") (2013 framework). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. 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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework issued by COSO (2013 framework).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows of the Company and our report dated February 27, 2017 expressed an unqualified opinion.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
February 27, 2017

ITEM 9B. OTHER INFORMATION.

None.

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 will disclose the nature of the amendment or waiver, its effective date and to whom it applies on our website and in a report on Form 8-K filed with the SEC.

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)," "Information Concerning Nominees and Continuing Directors," "Corporate Governance," "Committees of the Board - Audit Committee" 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) Report of Independent Registered Public Accounting Firm; and 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.
- Exhibit 4.1 Form of Indenture between Chesapeake Utilities Corporation and Boatmen's Trust Company, as Trustee, relating to its 8 1/4% Convertible Debentures, is incorporated herein by reference to Exhibit 4.2 of our Registration Statement on Form S-2, Reg. No. 33-26582, filed on January 13, 1989.
- Exhibit 4.2 Note Purchase Agreement dated December 27, 2000, between Chesapeake Utilities Corporation, as issuer, and Pacific Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 7.83% Senior Notes. †
- Exhibit 4.3 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 4.4 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 4.5 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 4.6 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 4.7 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 4.8 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 4.9 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 4.10 — 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 4.11 — 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 4.12 — 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 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* — Consulting Agreement dated January 2, 2013, between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.7 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
- Exhibit 10.5* — 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 10.6* — 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 10.7* — 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 10.8* — 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 10.9* — 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 10.10* — 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 10.11* — 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 10.12* — 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 10.13* — 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 10.14* — 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 filed herewith.
- Exhibit 10.15* — 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 10.16* — 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 10.17 — 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 10.18 — 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 10.19 — 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 filed herewith.
- Exhibit 10.20 — 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 10.21* — 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 12 — Computation of Ratio of Earning to Fixed Charges is filed herewith.
- Exhibit 14.1 — Code of Ethics for Financial Officers is filed is incorporated herein by reference to Exhibit 14.1 of our Annual Report on Form 10-K for the period ended December 31, 2014, File No. 001-11590.
- Exhibit 14.2 — Business Code of Ethics and Conduct is is incorporated herein by reference to Exhibit 14.2 of our Annual Report on Form 10-K for the period ended December 31, 2014, File No. 001-11590.
- 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.

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 27, 2017

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 27, 2017

/S/ BETH W. COOPER
Beth W. Cooper, Senior Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)
February 27, 2017

/S/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Chair of the Board and Director
February 27, 2017

/S/ RONALD G. FORSYTHE, JR.
Dr. Ronald G. Forsythe, Jr., Director
February 27, 2017

/S/ EUGENE H. BAYARD, ESQ
Eugene H. Bayard, Esq., Director
February 27, 2017

/S/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
February 27, 2017

/S/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
February 27, 2017

/S/ DIANNA F. MORGAN
Dianna F. Morgan, Director
February 27, 2017

/S/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
February 27, 2017

/S/ CALVERT A. MORGAN, JR.
Calvert A. Morgan, Jr., Director
February 27, 2017

/S/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
February 27, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation

The audit referred to in our report dated February 27, 2017 relating to the consolidated financial statements of Chesapeake Utilities Corporation (the "Company") as of December 31, 2016 and 2015 and for each of the years in the three-year period ended December 31, 2016, which is contained in Item 8 of this Form 10-K, also included the audits of the financial statement schedule listed in Item 15(a)2. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statement schedule based on our audits.

In our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
February 27, 2017

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					
2016	**$ 909**	**$ 985**	**$ 340**	**$ (1,325)**	**$ 909**
2015	$ 1,120	$ 979	$ 246	(1,436)	$ 909
2014	$ 1,635	$ 1,073	$ 85	(1,673)	$ 1,120

[1] Recoveries.
[2] Uncollectible accounts charged off.