CHESAPEAKE UTILITIES CORP
Form 10-K
February 29, 2016

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, 2015
Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION
(Exact name of registrant as specified in its charter)

State of Delaware (State or other jurisdiction of incorporation or organization)	51-0064146 (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 ý.
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 ý.
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 ý. 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 ý. 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	ý	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 ý.

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2015, 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 $781.9 million.

The number of shares of Chesapeake Utilities Corporation Inc.'s common stock outstanding as of February 17, 2016 was 15,276,316.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2016 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III.

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GLOSSARY OF DEFINITIONS

401(k) SERP: Supplemental Executive Retirement Savings Plan, which was subsequently merged into the Non-Qualified Deferred Compensation Plan
AFUDC: Allowance for funds used during construction
ASC: Accounting Standards Codification
ASU: Accounting Standards Update
Anderson Gas: Anderson Gas Service, Inc., a small propane distribution company located in Florida
Aspire Energy: Aspire Energy of Ohio, LLC, a wholly-owned subsidiary of Chesapeake Utilities, into which Gatherco merged on April 1, 2015
Austin Cox: Austin Cox Home Services, Inc., a wholly-owned subsidiary of Chesapeake Utilities, providing heating, ventilation and air conditioning, plumbing and electrical services
BravePoint: BravePoint, Inc., the former advanced information services subsidiary of Chesapeake Utilities, headquartered in Norcross, Georgia, 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 Onsight Services: Chesapeake Onsight Services, LLC, a wholly-owned subsidiary of Chesapeake Utilities
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
CHP: A combined heat and power plant being constructed by Eight Flags in Nassau County, Florida
CIC: Chesapeake Investment Company, a wholly-owned subsidiary of Chesapeake Service Company, which is an investment company incorporated in Delaware
Columbia: Columbia Gas Transmission, LLC
Company: Chesapeake Utilities Corporation, its divisions and subsidiaries, as appropriate in the context of the disclosure
Credit Agreement: An agreement between Chesapeake Utilities and the Lenders related to the Revolver
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 cash bonuses, executive performance shares, and directors’ retainers and fees; this Plan was subsequently merged into the Non-Qualified Deferred Compensation Plan
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

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Dts/d: Dekatherms per day
Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned 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
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: The natural gas system purchased by FPU from the City of Fort Meade, Florida
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.
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: Columbia Gulf Transmission Company
Gulf Power: Gulf Power Company
Gulfstream: Gulfstream Natural Gas System, LLC
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
IRS: Internal Revenue Service
JEA: The 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

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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
NAM: Natural Attenuation Monitoring
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
Note Agreement: Note Purchase Agreement entered into by Chesapeake Utilities with the Note Holders on September 5, 2013
Note Holders: PAR U Hartford Life & Annuity Comfort Trust, The Prudential Insurance Company of America, The Gibraltar Life Insurance Co., Ltd., The Penn Mutual Life Insurance Company, Thrivent Financial for Lutherans, United of Omaha Life Insurance Company, and Companion Life Insurance Company, which are collectively the lenders that entered into the Note Agreement with Chesapeake Utilities on September 5, 2013
NYSE: New York Stock Exchange
OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a new tariff associated with Eastern Shore's firm transportation service that enables Eastern Shore to forego 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
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
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
Retirement Savings Plan: Chesapeake Utilities' qualified 401(k) retirement savings plan
Revolver: The unsecured revolving credit facility issued to us by the Lenders
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
SEC: Securities and Exchange Commission
Senior Notes: Our unsecured long-term debt primarily issued to insurance companies on various dates
Series A Notes: Series A of the Senior Notes issued on December 16, 2013 pursuant to the Note Agreement

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Series B Notes: Series B of the Senior Notes issued on May 15, 2014 pursuant to the Note Agreement
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, over the next three years, 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
TETLP: Texas Eastern Transmission, LP
Transco: Transcontinental Gas Pipe Line Company, LLC
Xeron: Xeron, Inc., Chesapeake Utilities' wholly-owned propane wholesale marketing subsidiary, based in Houston, Texas

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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 fut 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 at, 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;
- the loss of customers due to a government-mandated sale of our utility distribution facilities;
- 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;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- 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;
- the capital intensive nature of our regulated energy businesses;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the impact on our cost 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 creditworthiness of counterparties with which we are engaged in transactions;
- 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 continue to hire, train and retain appropriately qualified personnel;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- 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 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 ability to construct facilities at or below estimated costs;
- possible increased federal, state and local regulation of the safety of our operations;

- the inherent hazards and risks involved in our energy businesses;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies; and
- risks related to cyber-attacks that could disrupt our business operations or result in failure of information technology systems.

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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, providing natural gas distribution and transmission, natural gas supply, gathering and processing, electric distribution and propane distribution service. The core of our business is regulated energy services, which provides stable earnings through our utility operations. Our unregulated businesses provide opportunities to achieve returns greater than those of a traditional utility. The following charts present operating income by type of energy served and geographic area for the year ended December 31, 2015 and average investment by type of energy served and geographic area as of December 31, 2015.

OPERATING SEGMENTS

We operate within two reportable segments: Regulated Energy and Unregulated Energy.

The Regulated Energy segment includes our natural gas distribution, natural gas transmission and electric distribution operations. 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.

The Unregulated Energy segment includes our propane distribution, propane wholesale marketing, natural gas marketing and natural gas supply, gathering and processing services, which are unregulated as to their rates and services. 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. In the future, our Unregulated Energy segment will include electricity and steam generation services from the CHP plant we are currently constructing in Nassau County, Florida. The revenues from these services will be included in the Unregulated Energy segment.

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The remainder of our operations is presented as “Other businesses and eliminations". Prior to September 30, 2014, our business included a third segment, "Other", which consisted primarily of BravePoint, our former advanced information services subsidiary. On October 1, 2014, we sold BravePoint. "Other businesses and eliminations" now solely consists of unregulated subsidiaries that own real estate leased to Chesapeake Utilities, as well as certain corporate costs not allocated to other operations.

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

The following table shows the size of each of our operating segments and other businesses based on operating income for the year ended December 31, 2015 and total assets as of December 31, 2015:

(dollars in thousands)	Operating Income			Total Assets		
Regulated Energy	$60,985	78	%	$870,559	82	%
Unregulated Energy	16,355	21	%	172,803	16	%
Other businesses	418	1	%	25,224	2	%
Total	$77,758	100	%	$1,068,586	100	%

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).

REGULATED ENERGY

Overview of Business

Regulated Energy is our largest segment and consists of: (i) our natural gas distribution operations in Delaware, Maryland and Florida; (ii) our electric distribution operation in Florida; and (iii) our natural gas transmission operations on the Delmarva Peninsula and in Florida. Our natural gas and electric distribution operations, which are local distribution utilities, 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 currently served with propane under PSC-approved tariff rates as we prepare to convert some of our underground propane distribution system customers to natural gas. These customers are included in the Delmarva natural gas distribution operation.

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Eastern Shore, our interstate natural gas transmission subsidiary, bills its customers based upon the FERC-approved tariff rates. Eastern Shore is also authorized by the FERC to negotiate rates 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 third-party customers and with certain affiliates. Our rates are designed to provide the opportunity to generate revenues to recover all prudently incurred costs and provide a return on rate base sufficient to pay interest on debt and a reasonable return for our stockholders. Rate base generally consists of the original cost of utility plant less accumulated depreciation on utility plant in service, working capital and certain other assets and, depending upon the particular regulatory jurisdiction, may also include deferred income tax liabilities and other additions or deletions.

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.

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. Accordingly, the volumes sold for these purposes are directly affected by the severity of summer and winter weather and can vary substantially from year to year. We measure the relative impact of weather by using an accepted degree-day methodology. Degree-day data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day’s average temperature. 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. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating degree-day. Each degree of temperature above 65 degrees Fahrenheit is counted as one cooling degree-day. Normal heating degree-days are based on the most recent 10-year average.

In an effort to stabilize the level of net revenues collected from customers of Chesapeake Utilities' Maryland division regardless of weather conditions, Chesapeake Utilities' 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. We do not currently have any weather normalization or “decoupled” rate mechanisms for our other local distribution utilities. We recently filed for approval of a weather normalization adjustment by the Delaware PSC for Chesapeake Utilities' Delaware division and by the Maryland PSC for Sandpiper, see Item 8, Financial Statements and Supplementary Data (Note 18, Rates and Other Regulatory Activities, in the Consolidated Financial Statements) for more information.

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Operational Highlights

The following table presents operating revenues, volume and average customers by customer class for our natural gas and electric distribution operations for the year ended December 31, 2015:

(in thousands)	Delmarva Natural Gas Distribution[2]		Florida Natural Gas Distribution [3]		FPU Electric Distribution	
Operating Revenues						
Residential	$63,745	61 %	$27,945	32 %	$46,686	59 %
Commercial	33,776	33 %	31,116	36 %	42,585	54 %
Industrial	7,214	7 %	21,988	25 %	3,111	4 %
Other [1]	(1,175)	(1)%	5,512	7 %	(12,954)	(17)%
Total Operating Revenues	$103,560	100 %	$86,561	100 %	$79,428	100 %
Volume (in Dts for natural gas/MWHs for electric)						
Residential	3,734,888	31 %	1,575,038	6 %	303,642	48 %
Commercial	3,696,839	30 %	7,834,533	32 %	313,757	49 %
Industrial	4,617,183	38 %	14,990,843	62 %	18,880	3 %
Other	82,655	1 %	(84,763)	— %	(1,740)	— %
Total	12,131,565	100 %	24,315,651	100 %	634,539	100 %
Average Customers						
Residential	63,901	90 %	66,900	90 %	24,039	76 %
Commercial	6,637	9 %	5,609	8 %	7,389	24 %
Industrial	118	1 %	1,702	2 %	2	— %
Other	5	— %	—	— %	—	— %
Total	70,661	100 %	74,211	100 %	31,430	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 operation includes Chesapeake Utilities' Delaware and Maryland divisions in addition to Sandpiper.

[3] Florida natural gas distribution operation includes Chesapeake Utilities' Florida division, FPU and FPU's Indiantown and Fort Meade divisions.

The following table presents operating revenues and design day capacity for Eastern Shore for the year ended December 31, 2015 and contracted firm transportation capacity at December 31, 2015:

(in thousands)	Eastern Shore	
Operating Revenues		
Local distribution companies - affiliated [1]	$18,320	39 %
Local distribution companies - non-affiliated	9,485	20 %
Commercial and industrial	18,995	41 %
Other [2]	44	— %
Total Operating Revenues	$46,844	100 %
Contracted firm transportation capacity (in Dts/d)		
Local distribution companies - affiliated	101,152	43 %

Local distribution companies - non-affiliated	67,293	28	%
Commercial and industrial	67,923	29	%
Total	236,368	100	%
Designed day capacity (in Dts/d)	236,368	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.

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Peninsula Pipeline contracts with both affiliated and non-affiliated customers to provide firm transportation service. All of the contracts provide a fixed annual transportation fee. For the year ended December 31, 2015, operating revenues of Peninsula Pipeline were $5.1 million, $3.8 million of which were related to service to FPU under a contract with FPU, which was previously approved by the Florida PSC. Peninsula Pipeline's operating revenue from FPU is eliminated against the cost of sales in consolidation; however, FPU includes this amount in its purchased fuel cost and recovers it through the fuel cost recovery mechanism.

Regulatory Matters

The following table highlights the key regulatory structure and 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
Commission Structure:	5 commissioners Part-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Gubernatorial Appointment	5 commissioners Full-Time Presidential Appointment	5 commissioners Full-Time Gubernatorial Appointment
Regulatory Jurisdiction:	Delaware PSC	Florida PSC	Florida PSC	Florida PSC	Maryland PSC	FERC	Maryland PSC
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	7/6/2007 [1]	7/14/2009	12/17/2008	4/28/2014	5/1/2006	12/30/2010	N/A[1]
Effective date of permanent rates	9/30/2008 [1]	1/14/2010	1/14/2010[2]	11/1/2014	12/1/2007	7/29/2011	N/A[1]
Rate increase (decrease) approved	$325,000 [1]	$2,536,300	$7,969,000	$3,750,000	$648,000	$805,000	N/A[1]
Rate of return approved	10.25% [1] [3]	10.80%[3]	10.85%[3]	10.25%[3]	10.75%[3]	13.90%[4]	N/A[1]

[1] We filed base rate proceedings for Chesapeake Utilities' Delaware division and Sandpiper on December 21, 2015 and December 1, 2015, respectively. See Item 8, Financial Statements and Supplementary Data (Note 18, Rates and Other Regulatory Activities, in the Consolidated Financial Statements) for more information.

(2) The effective date of the order approving the settlement agreement, which adjusted the rates originally approved on June 4, 2009.
(3) Allowed return on equity.
(4) Allowed pre-tax, pre-interest rate of return.

As of December 31, 2015, our investments in our regulated operations were as follows: $112.7 million for Delmarva natural gas distribution; $251.0 million for Florida natural gas and electric distribution; and $166.3 million for natural gas transmission.

The terms of the settlement agreement for the FPU electric division rate case prescribe an authorized return on equity range of 9.25 to 11.25 percent, with a mid-point of 10.25 percent. In addition, the FPU electric division cannot file for a base rate increase prior to December 2016, unless its allowed return on equity falls below the authorized range. If the allowed return on equity exceeds the authorized range, the Office of the Public Counsel can seek a rate decrease.

The terms of the settlement agreement in Eastern Shore's most recent base rate proceeding provided a five-year moratorium (which will end on December 31, 2016) on Eastern Shore's right to file a base rate increase and other parties' rights to challenge Eastern Shore's rates. However, Eastern Shore is allowed to file for rate adjustments during those five years in the event certain costs related to government-mandated obligations are incurred and Eastern Shore's pre-tax earnings do not equal or exceed 13.90 percent. Eastern Shore is also required to file a base rate proceeding by January 2017.

In May 2013, the Maryland PSC approved our application to acquire the ESG operating assets to transfer the ESG franchises to Sandpiper. The Maryland PSC also approved a new gas service tariff and rates applicable to natural gas and propane distribution customers in Worcester County, Maryland, and directed that Sandpiper file a base rate proceeding within two and one-half years. This proceeding was filed on December 1, 2015.

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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.

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 natural gas, electricity, oil, propane and other alternative 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

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

Chesapeake Utilities' Delaware and Maryland divisions use their firm transportation resources to meet a significant percentage of their projected demand requirements. They purchase firm natural gas supplies to meet those projected requirements with purchases of base load, daily spot supplies and storage service. They have both firm and interruptible transportation service contracts with four interstate “open access” pipeline companies (Eastern Shore, Transco, Columbia 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 and TETLP.

Chesapeake Utilities' Delaware division has 72,254 Dts of maximum daily firm transportation capacity with Eastern Shore through contracts expiring on various dates between 2016 and 2028. It also has a total of 66,483 Dts of maximum daily firm transportation capacity with three upstream pipelines through contracts expiring between 2016 and 2028. Chesapeake Utilities' Maryland division has 26,448 Dts/d of maximum firm transportation capacity with Eastern Shore through contracts expiring on various dates between 2016 and 2027 and a total of 26,228 Dts/d of maximum firm transportation capacity with three upstream pipelines through contracts expiring between 2016 and 2027. The Delaware and Maryland divisions also have the capability to use propane-air peak-shaving equipment to supplement or displace natural gas purchases.

Chesapeake Utilities' 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.

Sandpiper is a party to a capacity, supply and operating agreement with EGWIC to purchase propane over a six-year term. Approximately three years remain under this contract. Sandpiper's current annual commitment is estimated at approximately 6.5 million gallons. Sandpiper also has 2,450 Dts of maximum daily firm transportation capacity available from Eastern Shore through contracts expiring on various dates between 2016 and 2027.

In 2015, Chesapeake Utilities' Florida division's previous two firm transportation service agreements with FGT were consolidated under FPU's firm transportation agreements. Chesapeake Utilities' 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, all of 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.

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FPU has firm transportation service agreements with FGT, Florida City Gas and Peninsula Pipeline, ranging from 52,455 to 81,056 Dts/d. These agreements expire on various dates between 2020 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 also has a renewable energy purchase agreement with Rayonier to purchase between 1.7 MWH and 3.0 MWH of electricity annually through 2036. In September 2014, FPU entered into an agreement with its affiliate, Eight Flags, to purchase up to 20 MWH of electricity from a CHP plant located in Nassau County, Florida, once construction of the plant is completed. Both agreements with Rayonier and Eight Flags will serve a portion of FPU's electric distribution customer load in northeast Florida.

UNREGULATED ENERGY

Our Unregulated Energy segment provides propane distribution, propane wholesale marketing, natural gas marketing, supply, gathering and processing and 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 businesses by offering propane as a fuel source where natural gas is not readily available, or by providing natural gas marketing, supply, gathering and processing services to our customers. Through competitive pricing and supply management, these businesses provide the opportunity to generate returns greater than those of a traditional utility.

Propane Distribution

Our propane distribution operations sell propane primarily to residential, commercial/industrial and wholesale customers in Delaware, Maryland, Virginia and in 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. The customers' tanks are metered, and we read and bill the customers once a month.

Propane Distribution - Weather

Revenues from our propane distribution sales activities are affected by seasonal variations in weather conditions. Weather conditions directly influence the volume of propane used by our metered customers or sold and delivered to our bulk customers; specifically, their demand substantially increases during the winter months when propane is used for heating. The timing of deliveries to the bulk delivery customers can also vary significantly from year to year depending on weather variation. Accordingly, the propane volumes sold for heating are directly affected by the severity of winter weather and can vary substantially from year to year. Sustained warmer-than-normal temperatures will tend to reduce propane use, while sustained colder-than-normal temperatures will tend to increase consumption.

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Propane Distribution - Operational Highlights

For the year ended December 31, 2015, operating revenues, total gallons sold and average customers by customer class for our Delmarva and Florida propane distribution operations were as follows:

(in thousands)	Delmarva Peninsula and Pennsylvania		Florida	
Operating Revenues				
Residential bulk	$23,676	34 %	$5,554	31 %
Residential metered	7,857	11 %	4,770	27 %
Commercial bulk	16,261	23 %	4,533	26 %
Commercial metered	—	— %	1,862	11 %
Wholesale	18,355	26 %	673	4 %
Other [(1)]	4,259	6 %	272	1 %
Total Operating Revenues	$70,408	100 %	$17,664	100 %
Volume (in gallons)				
Residential bulk	9,511	20 %	1,320	22 %
Residential metered	3,749	8 %	960	16 %
Commercial bulk	12,228	26 %	2,215	38 %
Commercial metered	—	— %	747	12 %
Wholesale	21,173	46 %	741	12 %
Other	—	— %	(2)	— %
Total	46,661	100 %	5,981	100 %
Average customers				
Residential bulk	25,532	68 %	8,763	54 %
Residential metered	8,188	22 %	6,224	38 %
Commercial bulk	3,689	10 %	975	6 %
Commercial metered	—	— %	270	2 %
Wholesale	34	— %	7	— %
Total	37,443	100 %	16,239	100 %

(1) Operating revenues from "Other" sources include revenues from customer loyalty programs; delivery, service and appliance fees; and unbilled revenues.

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, independent producers of natural gas liquids and from Xeron. Although supplies of propane from these and other sources are generally readily available for purchase, extreme market conditions, such as significant fluctuation 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 our bulk storage facilities. We own various bulk propane storage facilities with an aggregate capacity of approximately 4.1 million gallons in Delaware, Maryland, Pennsylvania, Virginia and Florida. From these storage facilities, propane is delivered by “bobtail” trucks, owned and operated by us, to tanks located at the customers’ premises.

Propane Wholesale Marketing

Through Xeron, we market propane and crude oil to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States. Xeron enters into forward contracts with various counterparties to commit to purchase or sell an agreed-upon quantity of propane and crude oil at an agreed-upon price at a specified future date, which typically ranges from one to six months from the execution of the contract. At the expiration of the forward contracts, Xeron typically settles its purchases and sales financially, without taking physical delivery of the propane or crude oil. Xeron also enters into futures and other option contracts that are traded on the InterContinentalExchange, Inc. The level and profitability of the propane and crude oil wholesale marketing activity is affected by both propane and crude oil wholesale price volatility and liquidity in the wholesale market. In 2015, Xeron had operating revenues, net of the associated cost of propane and crude oil sold, totaling approximately $301,000. For further discussion of Xeron's wholesale marketing activities, market risks and controls that monitor Xeron's risks, refer to Item 7A, Management's Discussion and Analysis of Financial Condition and Results of Operations — Market Risk. Xeron does not own physical storage facilities or equipment to transport propane or crude oil; however, it contracts for storage and pipeline capacity to facilitate the sale of propane and crude oil on a wholesale basis.

Natural Gas Marketing

We provide natural gas supply and supply management services through PESCO to 2,996 customers in Florida, 30 customers located primarily on the Delmarva Peninsula and five customers operating in other states. In 2015, PESCO had operating revenues of $42.0 million in Florida, $7.5 million from customers located primarily on the Delmarva Peninsula and $6.8 million from other customers. 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 own or operate any natural gas transmission or distribution assets. The gas that PESCO sells is delivered to retail 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.

Other Unregulated Natural Gas Services

On April 1, 2015, we completed the merger with Gatherco, in which Gatherco merged with and into Aspire Energy, a then newly formed, wholly-owned subsidiary of Chesapeake Utilities. As a result, Aspire Energy is an unregulated natural gas infrastructure company with approximately 2,500 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 Consumers Gas Cooperative, which together serve more than 20,000 end-use customers. Aspire Energy primarily sources gas from 300 conventional producers and provides gathering and processing services necessary to maintain quality and reliability to its wholesale markets.

For the period from April 1, 2015 (the date the merger closed) to December 31, 2015, operating revenues and deliveries by customer class were as follows:

	Operating revenues (in thousands)	Deliveries (in Dts)
Supply to Columbia Gas of Ohio	$4,884	1,258
Supply to Consumers Gas Cooperative	4,019	635
Supply to Marketers - affiliated	3,330	1,342
Supply to Marketers - unaffiliated	2,507	1,009
Other (including natural gas gathering and processing)	1,992	260
Total	$16,732	4,504

Other Unregulated Businesses

We provide heating, ventilation and air conditioning, plumbing and electrical services to residential, commercial and industrial customers throughout the lower Delmarva Peninsula. FPU sells energy-related merchandise in Florida. Operating revenues in 2015 from these other unregulated businesses totaled $5.3 million.

OTHER BUSINESSES

Overview

Other businesses consists primarily of other unregulated subsidiaries, including Skipjack and ESRE that own real estate leased to affiliates; 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.

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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. At December 31, 2015, we have recorded $10.6 million in environmental liabilities associated with these MGP sites, representing our estimate of future costs principally related to two of the seven former MGP sites. The most significant site is located in West Palm Beach, Florida, where FPU previously operated an MGP and is currently implementing a remedial plan approved by the FDEP. The estimated cost of remediation for the West Palm Beach site ranges from approximately $4.5 million to $15.4 million. We are also currently assessing a remediation plan and actively remediating a former MGP site in Winter Haven, Florida. The estimated cost of remediation for the Winter Haven site is not expected to exceed $443,000. We have entered into a voluntary clean-up program for our former MGP site in Seaford Delaware, where the cost of potential remedial actions for the site is estimated to be between $273,000 and $465,000. We are also discussing with the MDE another former MGP site in Maryland.

Base rates of our local distribution utilities include, or are expected to include, recovery of environmental remediation costs adequate to fully recover our current estimate of remediation costs. We continue to expect that any costs related to environmental remediation and related activities beyond our current estimate will also be recoverable from customers through rates.

We completed the investigation, assessment and remediation of eight natural gas pipeline facilities in Ohio that Aspire Energy acquired from Gatherco pursuant to the merger. The costs incurred to date associated with remediation activities for these facilities, is approximately $1.0 million. Pursuant to the merger agreement, an escrow was established to fund certain claims by Chesapeake Utilities and Aspire Energy for indemnification by Gatherco, including environmental claims. Gatherco's indemnification obligations for environmental matters apply to remediation costs in excess of $431,250 and are capped at $1.65 million. We expect to be reimbursed for substantially all remediation costs we have incurred to date associated with these pipeline facilities in excess of $431,250.

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, 2015, we had a total of 832 employees, 116 of whom are union employees represented by two labor unions: the International Brotherhood of Electrical Workers and Commercial Workers Union, whose collective bargaining agreements expire in 2019.

FINANCIAL INFORMATION ABOUT GEOGRAPHICAL AREAS

All of our operations, customers and assets are located in the United States.

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 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. These reports, and amendments to these reports, that we file with or furnish to the SEC are also available on the SEC’s website, www.sec.gov. The public may also read and copy any materials that we file with the SEC at the SEC’s Public Reference Room, 100 F Street, N.E., Washington, DC 20549-5546. The public may obtain information from the Public Reference Room by calling the SEC at 1-800-SEC-0330.

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.

If we make any amendment to, or grant a waiver of, any provision of the Business Code of Ethics and Conduct or the Code of

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Ethics for Financial Officers applicable to our principal executive officer, president, principal financial officer, principal accounting officer or controller, the amendment or waiver will be disclosed within four business days in a press release, by website disclosure, or by filing a current report on Form 8-K with the SEC.

CERTIFICATION TO THE NYSE

Our Chief Executive Officer certified to the NYSE on May 20, 2015, 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 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. 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. However, 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.

A downgrade in our credit rating could adversely affect our access to capital markets and our cost of capital.

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 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 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.

Inflation may impact our results of operations, cash flows and financial position.

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for regulated operations and closely monitor the returns of our unregulated operations. There can be no assurance that we will be able to obtain adequate and timely rate increases to offset the effects of inflation. If we are unable to offset the effects of inflation through rate increases, our results of operations, cash flows, and financial position may be adversely affected.

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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.

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.

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. As a result of the extreme volatility and disruption in the domestic and international equity, bond and interest rate markets in recent years, the asset values and benefit obligations of Chesapeake Utilities' and FPU’s Pension Plans have fluctuated significantly since 2008. 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

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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; and (v) insufficient customer throughput commitments.

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 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 operation's 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 Consumers Gas Cooperative.

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.

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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 a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our aging employees retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to 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 on-going 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.

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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

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 interruption to 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.

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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 bulk propane storage facilities, with an aggregate capacity of approximately 4.1 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 our earnings from the 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.
A number of legislative proposals 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 are pending at the federal level. 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

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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.

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.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Key Properties

We own approximately 1,374 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 2,762 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 442 miles of natural gas transmission pipeline, extending from supply interconnects at Parkesburg, Daleville and Honey Brook, Pennsylvania; and Hockessin, Delaware, to 90 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 889 miles of electric distribution line in Jackson, Liberty, Calhoun and Nassau Counties, Florida.

We own approximately 378 miles of underground propane distribution mains in Delaware; Dorchester, Princess Ann, 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 3.2 million gallons, at 33 propane storage facilities 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 870,000 gallons at 17 propane storage facilities. Xeron does not own physical storage facilities or equipment to transport propane; however, it leases propane storage and pipeline capacity from non-affiliated third parties.

Through Aspire Energy, we own 16 natural gas gathering systems and approximately 2,500 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. 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: 1,885 miles of natural gas distribution mains (and related equipment) in its service areas; 20 miles of electric transmission line located in Nassau County, Florida; 889 miles of electric distribution line located in Jackson, Liberty, Calhoun and Nassau Counties in Florida; 17 propane storage facilities with a total capacity of 870,000 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 4A. EXECUTIVE OFFICERS OF THE REGISTRANT.

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.

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Name	Age	Position
Michael P. McMasters	57	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 Acc
Beth W. Cooper	49	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 Au
Elaine B. Bittner	46	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 Regulat
Stephen C. Thompson	55	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, Superint
Jeffry M. Householder	58	President of Florida Public Utilities Company (June 2010 - present) Prior to joining Chesapeake Utilities, Mr. Householder operated a consulting practice that provided busines
James F. Moriarty	58	Vice President, General Counsel & Corporate Secretary (March 2015 - present) Prior to joining Chesapeake Utiliti D.C.

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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 17, 2016, there were 2,398 holders of record of our common stock. Our common stock is listed on the NYSE under the symbol "CPK." The high, low and closing prices of our common stock and dividends declared per share for each calendar quarter during 2015 and 2014 are included in the below table. The high, low and closing prices and dividends declared per share of our common stock for the first and second quarters of 2014 have been adjusted for the three-for-two stock split effected as a stock dividend on September 9, 2014.

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
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
2014					
	March 31	$43.01	$37.49	$42.11	$0.2567
	June 30	$47.69	$39.77	$47.55	$0.2700
	September 30	$48.73	$39.28	$41.66	$0.2700
	December 31	$52.66	$40.88	$49.66	$0.2700

We have paid a cash dividend to our common stock stockholders for 55 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 2015 and 2014, totaling $1.1325 per share and $1.0667 per share, respectively.

Indentures to our long-term debt contain various restrictions which limit our ability to pay dividends. Each of our Senior Notes contains a "restricted payments" covenant. 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 (such as dividends) 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, 2015, our cumulative consolidated net income base was $285.0 million, offset by restricted payments of $138.4 million, leaving $146.6 million of cumulative net income free of restrictions.

FPU's first mortgage bonds, which are due in 2022, contain a similar restriction that limits the payment of dividends by FPU. The bonds provide that FPU cannot make dividend 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, 2015, FPU had a cumulative net income base of $116.3 million, offset by restricted payments of $37.6 million, leaving $78.7 million of cumulative net income of FPU free of restrictions based on this covenant.

No securities were sold during fiscal 2015 that were not registered under the Securities Act of 1933, as amended.

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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, 2015.

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, 2015 through October 31, 2015 [1]	377	$53.43	—	—
November 1, 2015 through November 30, 2015	—	—	—	—
December 1, 2015 through December 31, 2015	—	—	—	—
Total	377	$53.43	—	—

(1) In October, 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, 377 shares were purchased through the reinvestment of dividends.

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

Discussion of our compensation plans, for which shares of our common stock are authorized for issuance, is included in the portion of the Proxy Statement captioned “Equity Compensation Plan Information” to be filed no later than March 31, 2016, in connection with our Annual Meeting to be held on or about May 6, 2016, and is incorporated herein by reference.

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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, 2015, 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: AGL Resources, Inc., Atmos Energy Corporation, Delta Natural Gas Company, Inc., The Laclede Group, Inc., New Jersey Resources Corporation, Northwest Natural Gas Company, Piedmont Natural Gas Company, Inc., RGC Resources, Inc., South Jersey Industries, Inc., and WGL Holdings, Inc.

The comparison assumes $100 was invested on December 31, 2010 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.

	2010	2011	2012	2013	2014	2015
Chesapeake Utilities	$100	$108	$116	$158	$200	$233
Industry Index	$100	$121	$119	$142	$178	$214
S&P 500 Index	$100	$102	$118	$156	$177	$180

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ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,		
	2015	2014	2013
Operating [(1)]			
(in thousands)			
Revenues			
Regulated Energy	$301,902	$300,442	$264,637
Unregulated Energy	162,108	184,961	166,723
Other businesses and eliminations	(4,766)	13,431	12,946
Total revenues	$459,244	$498,834	$444,306
Operating income			
Regulated Energy	$60,985	$50,451	$50,084
Unregulated Energy	16,355	11,723	12,353
Other businesses and eliminations	418	105	297
Total operating income	$77,758	$62,279	$62,734
Net income from continuing operations	$41,140	$36,092	$32,787
Assets			
(in thousands)			
Gross property, plant and equipment	$1,070,263	$883,131	$805,394
Net property, plant and equipment	$854,950	$689,762	$631,246
Total assets	$1,068,586	$904,469	$837,522
Capital expenditures [(1)]	$142,713	$98,057	$108,039
Capitalization			
(in thousands)			
Stockholders' equity	$358,138	$300,322	$278,773
Long-term debt, net of current maturities	149,340	158,486	117,592
Total capitalization	$507,478	$458,808	$396,365
Current portion of long-term debt	9,151	9,109	11,353
Short-term debt	173,397	88,231	105,666
Total capitalization and short-term financing	$690,026	$556,148	$513,384

(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.

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For the Year Ended December 31,						
2012	2011	2010	2009[(2)]	2008	2007	2006
$246,208	$256,226	$269,438	$138,671	$116,123	$128,566	$124,438
133,049	149,586	146,793	119,973	161,290	115,190	94,320
13,245	12,215	11,315	10,141	14,030	14,530	12,442
$392,502	$418,027	$427,546	$268,785	$291,443	$258,286	$231,200
$46,999	$43,911	$43,267	$26,668	$23,833	$21,739	$18,618
8,355	9,619	8,150	8,390	3,600	5,244	3,650
1,281	175	513	(1,322)	1,046	1,131	1,064
$56,635	$53,705	$51,930	$33,736	$28,479	$28,114	$23,332
$28,863	$27,622	$26,056	$15,897	$13,607	$13,218	$10,748
$697,159	$625,488	$584,385	$543,905	$381,689	$352,838	$325,836
$541,781	$487,704	$462,757	$436,587	$280,671	$260,423	$240,825
$733,746	$709,066	$670,993	$615,811	$385,795	$381,557	$325,585
$78,210	$44,431	$46,955	$26,294	$30,844	$30,142	$49,154
$256,598	$240,780	$226,239	$209,781	$123,073	$119,576	$111,152
101,907	110,285	89,642	98,814	86,422	63,256	71,050
$358,505	$351,065	$315,881	$308,595	$209,495	$182,832	$182,202
8,196	8,196	9,216	35,299	6,656	7,656	7,656
61,199	34,707	63,958	30,023	33,000	45,664	27,554
$427,900	$393,968	$389,055	$373,917	$249,151	$236,152	$217,412

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	For the Year Ended December 31,		
	2015	2014	2013
Common Stock Data and Ratios			
Basic earnings per share from continuing operations (1) (5)	$2.73	$2.48	$2.27
Diluted earnings per share from continuing operations (1) (5)	$2.72	$2.47	$2.26
Return on average equity from continuing operations (1)	12.1 %	12.2 %	12.2 %
Common equity / total capitalization	70.6 %	65.5 %	70.3 %
Common equity / total capitalization and short-term financing	51.9 %	54.0 %	54.3 %
Book value per share (5)	$23.45	$20.59	$19.28
Market price:			
High	$61.130	$52.660	$40.780
Low	$44.370	$37.493	$30.560
Close	$56.750	$49.660	$40.013
Weighted average number of shares outstanding (5)	15,094,423	14,551,308	14,430,962
Shares outstanding at year-end (5)	15,270,659	14,588,711	14,457,345
Registered common shareholders	2,396	2,329	2,345
Cash dividends declared per share (5)	$1.13	$1.07	$1.01
Dividend yield (annualized) (3)	2.0 %	2.2 %	2.6 %
Payout ratio from continuing operations (1) (4)	41.5 %	43.0 %	44.6 %
Additional Data			
Customers			
Natural gas distribution	144,872	141,227	138,210
Electric distribution	31,430	31,272	31,151
Propane distribution	53,682	53,272	51,988
Volumes			
Natural gas deliveries (in Dts)	79,564,618	77,623,201	74,117,121
Electric Distribution (in MWHs)	634,539	643,332	649,025
Propane distribution (in thousands of gallons)	52,643	53,525	48,511
Other unregulated natural gas services deliveries (in Dts)	4,504	—	—
Heating degree-days (Delmarva Peninsula)			
Actual HDD	4,363	4,826	4,638
10-year average HDD (normal)	4,496	4,483	4,454
Heating degree-days (Florida)			
Actual HDD	569	888	671
10-year average HDD (normal)	859	856	885
Cooling degree-days (Florida)			
Actual CDD	3,338	2,705	2,750
10-year average CDD (normal)	2,760	2,768	2,750
Propane bulk storage capacity (in thousands of gallons)	4,060	3,833	3,566
Total employees	832	753	842

(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) 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.

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For the Year Ended December 31,

2012	2011	2010	2009(2)	2008	2007	2006
$2.01	$1.93	$1.83	$1.45	$1.33	$1.31	$1.19
$1.99	$1.91	$1.82	$1.43	$1.32	$1.29	$1.17
11.6 %	11.6 %	11.6 %	11.2 %	11.2 %	11.5 %	11.0 %
71.6 %	68.6 %	71.6 %	68.0 %	58.7 %	65.4 %	61.0 %
60.0 %	61.1 %	58.2 %	56.1 %	49.4 %	50.6 %	51.1 %
$17.82	$16.78	$15.84	$14.89	$12.02	$11.76	$11.08
$32.613	$29.687	$28.133	$23.333	$23.227	$24.833	$23.767
$26.593	$24.000	$18.673	$14.680	$14.620	$18.667	$18.600
$30.267	$28.900	$27.680	$21.367	$20.987	$21.233	$20.433
14,379,216	14,333,699	14,211,831	10,969,980	10,217,772	10,114,562	9,048,693
14,396,248	14,350,959	14,286,293	14,091,471	10,240,682	10,166,115	10,032,126
2,396	2,481	2,482	2,670	1,914	1,920	1,978
$0.96	$0.91	$0.87	$0.83	$0.81	$0.78	$0.77
3.2 %	3.2 %	3.2 %	3.9 %	3.9 %	3.7 %	3.8 %
47.8 %	47.4 %	47.6 %	57.6 %	60.5 %	60.2 %	65.2 %
124,015	121,934	120,230	117,887	65,201	62,884	59,132
31,066	30,986	30,966	31,030	—	—	—
49,312	48,824	48,100	48,680	34,981	34,143	33,282
66,784,690	57,493,022	49,310,314	50,159,227	46,539,142	42,910,964	41,826,357
670,998	694,653	751,507	105,739	—	—	—
37,438	37,387	39,807	32,546	27,956	29,785	24,243
—	—	—	—	—	—	—
3,936	4,221	4,831	4,729	4,431	4,504	3,931
4,491	4,499	4,528	4,462	4,401	4,376	4,372
633	753	1,501	911	—	—	—
915	920	863	849	—	—	—
2,871	2,858	2,859	2,770	—	—	—
2,756	2,718	2,695	2,687	—	—	—
3,400	3,351	3,041	3,042	2,471	2,441	2,315
738	711	734	757	448	445	437

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

(5) 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.

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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." Gross margin 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. 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.

Shares and per share amounts for all periods presented reflect the three-for-two stock split declared on July 2, 2014, which was effected in the form of a stock dividend and distributed on September 8, 2014. 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 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. The key elements of this strategy include:

- executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;
- expanding the propane distribution business in existing and new markets through our bulk delivery capabilities, our community gas system services and our propane vehicle fuel offerings ;
- expanding both our regulated energy and unregulated energy businesses through strategic acquisitions;
- utilizing our expertise across our various businesses to improve overall performance;
- pursuing and entering new unregulated energy markets and business lines that will complement our existing strategy and operating units while capitalizing on opportunities across the natural gas value chain;
- enhancing marketing channels to attract new customers;
- providing reliable and responsive customer service to existing customers so they become our best promoters;
- engaging our customers through a distinctive service excellence initiative;
- developing and retaining a high-performing team that advances our goals;
- empowering and engaging our employees to live our brand and vision;
- demonstrating community leadership and engaging our local communities and governments in a cooperative and mutually beneficial way;

- maintaining a capital structure that enables us to access capital as needed;

- continuing to build our brand in a culture with a shared mission, vision and values;
- achieving strong growth in earnings and capital investment, thereby generating above regulated return on equity performance;
- maintaining a consistent and competitive dividend for stockholders;
- maximizing shareholder value; and
- creating and maintaining a diversified customer base, energy portfolio and utility foundation.

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 estimates. Management believes that the following policies require significant estimates or other judgments of matters that are inherently uncertain. These policies and their application have been reviewed by our Audit Committee.

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with FASB 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. As more fully described in Item 8, Financial Statements and Supplementary Data (see Note 2, Summary of Significant Accounting Policies, in the Consolidated Financial Statements), we have recorded regulatory assets of $85.8 million and regulatory liabilities of $50.4 million at December 31, 2015. 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 (see 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. At December 31, 2015, we have recorded $10.6 million in environmental liabilities associated with these MGP sites, representing our estimate of such future costs. We have also recorded regulatory and other assets to reflect future recovery of those costs in rates and have recorded $4.2 million of such assets at December 31, 2015, representing the amount of our environmental remediation costs to be recovered in future rates. There is uncertainty in these amounts, as the EPA, or other applicable state environmental authority, may not have selected the final remediation methods. In addition, there is uncertainty with regard to amounts that may be recovered from other potentially responsible parties.

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. The costs incurred to date associated with remediation activities for these facilities is approximately $1.0 million. Pursuant to the merger agreement, an escrow was established to fund certain claims by Chesapeake Utilities and Aspire Energy for indemnification by Gatherco, including environmental claims. Gatherco's indemnification obligations for environmental matters apply to remediation costs in excess of $431,250 and are capped at 1.65 million. We expect to be reimbursed for substantially all remediation costs we have incurred to date associated with these pipeline facilities in excess of $431,250.

Derivatives

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 wholesale marketing activities. We continually monitor the use of these instruments to ensure compliance with our risk management policies and account

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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 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.

During the last three years, we had the following derivative assets and liabilities:

- Propane forward contracts entered into by Xeron;
- Propane put options, call options and swap agreements entered into by Sharp; and
- Natural gas futures contracts entered into by PESCO.

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 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 (See Note 7: Derivative Instruments, in the Consolidated Financial Statements).

As of December 31, 2015, we recorded $153,000 and $433,000 of derivative assets and liabilities, respectively. As of December 31, 2014, we have recorded $1.1 million and $1.0 million of derivative assets and liabilities, respectively.

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 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.

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.

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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 2015 indicated no goodwill impairment. At December 31, 2014, we recorded a non-cash, pre-tax impairment charge of $412,000 related to the impairment of goodwill and intangible assets associated with the 2013 acquisition of certain assets of Austin Cox.

Other Asset 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 impairment are present, we record an impairment loss equal to the excess of the assets' carrying value over its fair value, if any.

On May 29, 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 may also receive $750,000 in additional cash and discounts on future services; however, the receipt or retention of additional cash and future discounts is contingent upon engaging this vendor to provide agreed-upon services over the next five years. We will establish a regulatory asset for the portion of impairment loss not recovered from the vendor when future recovery through rates is probable.

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 (See 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 2015, actuarial assumptions include expected long-term rates of return on plan assets of 6.00 percent and 7.00 percent for Chesapeake Utilities' pension plan and FPU's pension plan, respectively, and discount rates of 3.50 percent and 3.75 percent for Chesapeake Utilities' and FPU's plans, respectively. The discount rate for each plan was determined by management considering high-quality corporate bond rates, such as 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 $19,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $19,000.

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. We adopted a new mortality table (RP 2014 MP-2015), which was developed by the Society of Actuaries and published in 2015.

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

$126,000 and would not have an impact on the postretirement and Chesapeake SERP because these plans are not funded.

The health care inflation rate for 2015 used to calculate the benefit obligation is five percent for medical and six percent for prescription drugs for the Chesapeake Postretirement Plan; and five percent 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 $335,000 as of December 31, 2015, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2015 by approximately $13,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $268,000 as of December 31, 2015, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2015 by approximately $10,000.

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 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.

As of December 31, 2015 and 2014, we recorded total liabilities of $50,000 and $100,000, respectively, associated with unrecognized income tax benefits. As of December 31, 2015 and 2014, we recorded total liabilities of $310,000 and $724,000, respectively, related to taxes other than income.

OVERVIEW AND HIGHLIGHTS

(in thousands except per share)			Increase			Increase
For the Year Ended December 31,	2015	2014	(decrease)	2014	2013	(decrease)
Business Segment:						
Regulated Energy	$60,985	$50,451	$10,534	$50,451	$50,084	$367
Unregulated Energy	16,355	11,723	4,632	11,723	12,353	(630)
Other businesses and eliminations	418	105	313	105	297	(192)
Operating Income	77,758	62,279	15,479	62,279	62,734	(455)
Gains from sales of businesses	—	7,139	(7,139)	7,139	—	7,139
Other income, net of other expenses	293	101	192	101	372	(271)
Interest charges	10,006	9,482	524	9,482	8,234	1,248
Income Before Income Taxes	68,045	60,037	8,008	60,037	54,872	5,165
Income taxes	26,905	23,945	2,960	23,945	22,085	1,860
Net Income	$41,140	$36,092	$5,048	$36,092	$32,787	$3,305
Earnings Per Share of Common Stock						
Basic	$2.73	$2.48	$0.25	$2.48	$2.27	$0.21
Diluted	$2.72	$2.47	$0.25	$2.47	$2.26	$0.21

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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)	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 a customer billing system settlement	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 (see Major Projects and Initiatives table)	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
Propane wholesale marketing	(1,179)	(709)	(0.05)
Decreased wholesale propane sales	(446)	(268)	(0.02)
	23,396	14,066	0.95
Increased Other Operating Expenses:			
Higher payroll and benefits 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

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2014 compared to 2013

Our net income increased by approximately $3.3 million, or $0.21 per share (diluted) in 2014, compared to 2013. Key variances included:

(in thousands, except per share amounts)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2013 Reported Results	$54,872	$32,787	$2.26
Adjusting for unusual items:			
Gains on sales of businesses	7,139	4,266	0.29
Asset impairment charges	(6,880)	(4,111)	(0.28)
Weather impact	2,799	1,672	0.11
Regulatory recovery of litigation-related costs in 2013	(1,494)	(893)	(0.06)
Accrual for additional taxes other than income in 2013	990	592	0.04
One-time sales tax expense recorded by Sandpiper in conjunction with the 2013 ESG acquisition	726	434	0.03
	3,280	1,960	0.13
Increased (Decreased) Gross Margins:			
Major projects (see Major Projects and Initiatives table)			
Service expansions	5,591	3,341	0.23
Margin generated by Sandpiper	5,544	3,313	0.23
GRIP	2,862	1,710	0.12
Other natural gas growth	2,671	1,596	0.11
Increased wholesale propane sales	1,391	831	0.06
FPU electric base rate increase	1,269	758	0.05
	19,328	11,549	0.80
Increased Other Operating Expenses:			
Higher payroll and benefits costs	(5,164)	(3,085)	(0.21)
Expenses from acquisitions	(3,526)	(2,107)	(0.14)
Higher depreciation, asset removal and property tax costs due to new capital investments	(2,842)	(1,698)	(0.12)
Higher facility maintenance and service contractor costs	(2,735)	(1,634)	(0.11)
Increased incentive compensation	(1,356)	(810)	(0.06)
Transaction costs	(760)	(454)	(0.03)
	(16,383)	(9,788)	(0.67)
Interest Charges	(1,247)	(745)	(0.05)
Net Other Changes	187	329	—
Year ended December 31, 2014 Reported Results	$60,037	$36,092	$2.47

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SUMMARY OF KEY FACTORS

Major Projects and Initiatives

The following table summarizes gross margin for our existing and future major projects and initiatives:

	Gross Margin for the Period							
(in thousands)	Year Ended December 31,			Year Ended December 31,			Estimate	
	2015	2014	Variance	2014	2013	Variance	2016	2017
Existing major projects and initiatives	$25,270	$7,115	$18,155	$7,115	$—	$7,115	$37,275	$36,493
Future major projects and initiatives	—	—	—	—	—	—	7,200	18,150
Total	$25,270	$7,115	$18,155	$7,115	$—	$7,115	$44,475	$54,643

Existing Major Projects and Initiatives

The following table summarizes our major projects and initiatives commenced since 2014:

	Gross Margin for the Period [(1)]							
(in thousands)	Year Ended December 31,			Year Ended December 31,			Estimate for	
	2015	2014	Variance	2014	2013	Variance	2016	2017
Acquisition:								
Aspire Energy [(2)]	$6,324	$—	$6,324	$—	$—	$—	$12,824	$14,198
Natural Gas Transmission Expansions and Contracts:								
Short-term contracts								
New Castle County, Delaware	$2,682	$2,026	$656	$2,026	$—	$2,026	$2,294	$1,561
Kent County, Delaware [(3)]	2,270	—	2,270	—	—	—	3,748	—
Total short-term Contracts	4,952	2,026	2,926	2,026	—	2,026	6,042	1,561
Long-term Contracts								
Kent County, Delaware	1,844	463	1,381	463	—	463	1,815	1,789
Polk County, Florida	908	—	908	—	—	—	1,627	1,627
Total long-term contracts	$2,752	$463	$2,289	$463	$—	$463	$3,442	$3,416
Total Expansions & Contracts	$7,704	$2,489	$5,215	$2,489	$—	$2,489	$9,484	$4,977
Florida GRIP	$7,508	$3,357	$4,151	$3,357	$—	$3,357	$11,405	$13,756
Florida Electric Rate Case	$3,734	$1,269	$2,465	$1,269	$—	$1,269	$3,562	$3,562
Total Existing Major Projects and Initiatives	$25,270	$7,115	$18,155	$7,115	$—	$7,115	$37,275	$36,493

[(1)] Does not include gross margin of $21.8 million and $13.2 million for the year ended December 31, 2014 and 2013, respectively, related to projects initiated prior to 2014. These projects were previously disclosed and are excluded from this table as they no longer result in period-over-period variances

(2) During the year ended December 31, 2015 we incurred $5.8 million, in other operating expenses related to Aspire Energy's operation.
(3) Gross margin of $2.3 million is attributable to interruptible service and a short-term OPT ≤ 90 Service Eastern Shore provided to an industrial customer beginning in April 2015. These short-term services will be replaced by a 20-year OPT ≤ 90 Service.

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Gatherco Acquisition

On April 1, 2015, we completed the merger with Gatherco, pursuant to which Gatherco merged with and into Aspire Energy. Aspire Energy is an unregulated natural gas infrastructure company with approximately 2,500 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 Consumers Gas Cooperative, which together serve more than 20,000 end-use customers. Aspire Energy primarily sources gas from 300 conventional producers and provides gathering and processing services necessary to maintain quality and reliability to its wholesale markets.

Aspire Energy generated $6.3 million in additional gross margin and incurred $5.8 million in other operating expenses for the year ended December 31, 2015. The financial results of Aspire Energy had a minimal impact on our earnings per share in 2015, because the merger was completed after the first quarter and Ohio experienced warmer than normal weather during the fourth quarter of 2015. The first and fourth quarters include key winter months, which historically produced a significant portion of Gatherco's annual earnings. This acquisition is expected to be accretive to our earnings in the first full year of operations, which will include the first quarter of 2016.

Service Expansions

During 2014, Eastern Shore, executed a one-year contract with an industrial customer in New Castle County, Delaware to provide 50,000 Dts/d of additional transmission service from April 2014 to April 2015. This contract was subsequently amended to provide 55,580 Dts/d of transmission service at a lower reservation rate through August 2020. The extension of the contract, net of the impact of the lower rate, generated additional gross margin of $334,000 for the year ended December 31, 2015 compared to 2014.

In December 2014 and November 2015, Eastern Shore executed two separate short-term contracts with the same customer in New Castle County, Delaware, to provide an additional 10,000 Dts/d of OPT ≤ 90 Service from December 2014 to March 2015 and November 2015 to March 2016, respectively. These short-term contracts generated additional gross margin of $322,000 for the year ended December 31, 2015 compared to 2014.

On October 1, 2014, Eastern Shore commenced a new lateral service to an industrial customer facility in Kent County, Delaware. This service commenced after construction of new facilities, including approximately 5.5 miles of pipeline lateral and metering facilities extending from Eastern Shore's mainline to the new industrial customer facility. This service generated additional gross margin of $1.4 million for 2015 compared to 2014. We expect this service to generate approximately $1.2 million to $1.8 million of annual gross margin during the 37-year service period.

In April 2015, Eastern Shore commenced interruptible service to the same industrial customer in Kent County, Delaware and generated additional gross margin of $1.6 million for 2015. Interruptible service concluded in December 2015 and was replaced by a short-term OPT ≤ 90 Service, which generated additional gross margin of $646,000 during 2015. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year OPT ≤ 90 Service.

On January 16, 2015, the Florida PSC approved a firm transportation agreement between Peninsula Pipeline and our Florida natural gas distribution division. Under 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, generating $908,000 of additional gross margin for the year ended December 31, 2015. Once completed, all phases of this service will generate an estimated annual gross margin of $1.6 million.

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 program's inception in August 2012, our Florida natural gas distribution operations have invested $76.7 million to replace 162 miles of qualifying distribution mains, $32.8 million of which was invested during 2015. We expect to invest an additional $21.1 million in this program in 2016. The increased investment in GRIP generated additional gross margin of $4.2 million for 2015, compared to 2014.

Florida Electric Rate Case

On September 15, 2014, the Florida PSC approved a settlement agreement between FPU and the Florida Office of Public Counsel in FPU's base rate case filing for its electric operation, which included, among other things, an increase in FPU's annual revenue requirement of approximately $3.8 million and a 10.25 percent rate of return on common equity. The new rates became effective for all meter reads on or after November 1, 2014. Previously, the Florida PSC approved interim rate relief, effective for meter readings on or after August 10, 2014. The higher base rates in FPU's electric operation generated $2.5 million in additional gross margin for 2015 compared to 2014.

Future Major Projects and Initiatives

White Oak Mainline Expansion Project: In December 2014, Eastern Shore entered into a precedent agreement with an industrial customer in Kent County, Delaware, to provide a 20-year natural gas transmission service for 45,000 Dts/d for the customer's new facility, upon the satisfaction of certain conditions. This new service will be provided as OPT ≤ 90 Service and is expected to generate at least $5.8 million in annual gross margin. In November 2014, Eastern Shore requested authorization by the FERC to construct 7.2 miles of 16-inch pipeline looping and 3,550 horsepower of new compression in Delaware to provide this service. The updated, estimated cost of these new facilities is approximately $32.0 - $35.0 million. As previously discussed, during the year ended December 31, 2015, we generated $2.3 million in additional gross margin by providing interruptible service and short-term OPT ≤ 90 Service to this customer. The estimated annual gross margin from this project, once it is in service, will be approximately $5.8 million.

System Reliability Project: On May 22, 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 proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore’s customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days in 2014 and 2015. 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 and an order granting the requested authorization. This project will be included in Eastern Shore's upcoming 2017 rate case filing. The estimated cost of the project is $32.1 million. The estimated annual gross margin associated with this project, assuming recovery in the 2017 rate case filing, is approximately $4.5 million.

TETLP Capacity Expansion Project: On October 13, 2015, Eastern Shore submitted an application to the FERC to make certain measurement and related improvements at its TETLP interconnect facilities, which will 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 the project. We anticipate that, once completed, this project will generate approximately $2.8 million in annual gross margin.

Eight Flags: Eight Flags, one of our unregulated energy subsidiaries, is engaged in the development and construction of a CHP plant in Nassau County, Florida. This CHP plant, which will consist of a natural-gas-fired turbine and associated electric generator, is designed to generate approximately 20 megawatts of base load power and will include a heat recovery system generator capable of providing approximately 75,000 pounds per hour of unfired steam. Eight Flags will sell the power generated from the CHP plant to FPU for distribution to its retail electric customers pursuant to a 20-year power purchase agreement. It will also sell the steam to an industrial customer pursuant to a separate 20-year contract. FPU will transport natural gas through its distribution system to Eight Flags’ CHP plant, which will then produce the power and steam. On a consolidated basis, this project is expected to generate approximately $7.3 million in annual gross margin, which could fluctuate based upon various factors, including, but not limited to, the quantity of steam delivered and the CHP plant’s hours of operations. Our total projected investment, by Eight Flags and our affiliates, to construct the CHP plant and associated facilities is approximately $40.0 million.

The following table summarizes estimated gross margin for the foregoing projects (dollars in thousands):

	Estimated Margin for [1]		
Project	2016	2017	Annualized Margin
White Oak Mainline Expansion Project in Kent County, Delaware	$1,300	$5,800	$5,800
Eastern Shore System Reliability Project	—	2,250	4,500
Eastern Shore TETLP Capacity Expansion Project	2,200	2,800	2,800
Eight Flags CHP plant in Nassau County, Florida	3,700	7,300	7,300
	$7,200	$18,150	$20,400

[1]Estimated margin for these projects is based on current tariff or negotiated rates.

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Weather and Consumption

Significantly warmer temperatures in 2015, particularly during the last three months of the year when the demand for natural gas and propane is normally high, had a large negative impact on the our earnings. Lower customer energy consumption, directly attributable to warmer than normal temperatures during 2015, reduced gross margin for the year ended December 31, 2015, by $4.4 million, compared to 2014. The following tables summarize the HDD and CDD information for the years ended December 31, 2015 and 2014, and the gross margin variance resulting from weather fluctuations in those periods.

HDD and CDD Information

For the Periods Ended December 31,	2015	2014	Variance	2014	2013	Variance
Delmarva						
Actual HDD	4,363	4,826	(463)	4,826	4,638	188
10-Year Average HDD ("Normal")	4,496	4,483	13	4,483	4,454	29
Variance from Normal	(133)	343		343	184	
Florida						
Actual HDD	569	888	(319)	888	671	217
10-Year Average HDD ("Normal")	859	856	3	856	885	(29)
Variance from Normal	(290)	32		32	(214)	
Ohio [1]						
Actual HDD	2,404	—	N/A	—	—	N/A
10-Year Average HDD ("Normal")	2,903	—	N/A	—	—	N/A
Variance from Normal	(499)	—		—	—	
Florida						
Actual CDD	3,338	2,705	633	2,705	2,750	(45)
10-Year Average CDD ("Normal")	2,760	2,768	(8)	2,768	2,750	18
Variance from Normal	578	(63)		(63)	—	

[1] HDD for Ohio is presented from April 1, 2015 through December 31, 2015.

Gross Margin Variance attributed to Weather

(in thousands)	2015 vs. 2014	2015 vs. Normal	2014 vs. 2013	2014 vs. Normal
Delmarva				
Regulated Energy	$(1,414)	$(183)	$232	$765
Unregulated Energy	(780)	593	1,431	1,324
Florida				
Regulated Energy	(1,326)	(922)	877	145
Unregulated Energy	(888)	297	292	485
Total	$(4,408)	$(215)	$2,832	$2,719

Propane Prices

Higher retail margins per gallon generated $7.0 million in additional gross margin by the Delmarva propane distribution operation for 2015 compared to 2014. A large decline in propane prices in the first quarter of 2015 had a significant impact on the amount of revenue and cost of sales associated with our propane distribution operations. Based on the Mont Belvieu wholesale propane index, propane prices in the first quarter of 2015 were approximately 55 percent lower than prices in the same quarter in 2014. As a result of favorable supply management and hedging activities, the Delmarva propane distribution operation experienced a

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decrease in its average propane cost in addition to the decrease in wholesale prices, which generated increased retail margins per gallon. During the remainder of 2015, wholesale propane prices continued to remain significantly lower than prices in 2014.

In Florida, higher retail propane margins per gallon as a result of local market conditions generated $1.9 million of additional gross margin for 2015 compared to 2014.

These market conditions include 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. The level of retail margins per gallon generated during 2015 is not typical and, therefore, is not included in our long-term financial plans or forecasts.

Xeron, which benefits from wholesale price volatility by entering into trading transactions, experienced a gross margin decrease of $1.2 million, for 2015 compared to 2014, due to lower wholesale price volatility.

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $1.4 million in additional gross margin for 2015, compared to 2014, due to an increase in residential, commercial and industrial customers served. The number of residential customers on the Delmarva Peninsula increased by 2.7 percent in 2015 compared to 2014. The natural gas distribution operations in Florida generated $1.9 million in additional gross margin for 2015, compared to 2014, due primarily to an increase in commercial and industrial customers in Florida.

Capital Expenditures

Our capital expenditures for 2015 were $142.7 million, excluding the net amount expended to acquire Gatherco of $52.5 million. This represents a significant increase over the level of annual capital expenditures during the preceding three years, which averaged $94.8 million per year. Major expenditures to date associated with projects currently underway, such as the Eight Flags' CHP plant and associated facilities, anticipated new facilities to serve an industrial customer in Kent County, Delaware under the OPT ≤ 90 Service, and additional GRIP investments during 2015, account for approximately $99.0 million of the capital expenditures in 2015.

The 2016 capital budget is $179.3 million, a significant increase over the prior three years' average annual level of capital expenditures, excluding the Gatherco acquisition, due to a shifting in the capital outlay from 2015 to 2016 for several ongoing projects, including but not limited to the Eight Flags CHP plant, White Oak mainline expansion, and Eastern Shore's system reliability projects; additional expansions of our natural gas distribution and transmission systems; continued natural gas infrastructure improvement activities as well as expenditures for continued replacement under the Florida GRIP; replacement of several facilities and systems; and other strategic initiatives and investments expected in 2016. In addition, approximately $30.0 million is included in the 2016 capital budget for projects that are in the early development stage.

In order to fund the 2016 capital expenditures, we may further increase the level of borrowings during 2016 to supplement cash provided by operating activities. Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent, and we have maintained a ratio of equity to total capitalization, including short-term borrowings, between 52 and 54 percent during the past three years. By increasing the level of debt during 2015 and 2016 to fund capital expenditures, our ratio of equity to total capitalization, including short-term borrowings, will temporarily decline.

On October 8, 2015, we entered into the Revolver with the Lenders, 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 entered into a long-term private placement Shelf Agreement also for $150.0 million.

For larger capital projects, we will seek to align, as much as feasible, any such long-term debt or equity issuance(s) with the earnings associated with commencement of service on such projects. The exact timing of any long-term debt or equity issuance(s) will be based on market conditions.

Capital expenditures are subject to continuous review and modification by our management and Board of Directors, and some anticipated capital expenditures are subject to approval by the applicable regulators.

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REGULATED ENERGY

For the Year Ended December 31,	2015	2014	Increase (decrease)	2014	2013	Increase (decrease)
(in thousands)						
Revenue	$301,902	$300,442	$1,460	$300,442	$264,637	$35,805
Cost of sales	122,814	134,560	(11,746)	134,560	118,817	15,743
Gross margin	179,088	165,882	13,206	165,882	145,820	20,062
Operations & maintenance	83,616	76,046	7,570	76,046	65,713	10,333
(Gain from a settlement)/asset impairment charge	(1,497)	6,449	(7,946)	6,449	—	6,449
Depreciation & amortization	24,195	21,915	2,280	21,915	19,822	2,093
Other taxes	11,789	11,021	768	11,021	10,201	820
Other operating expenses	118,103	115,431	2,672	115,431	95,736	19,695
Operating Income	$60,985	$50,451	$10,534	$50,451	$50,084	$367

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 a result of an increase in gross margin of $13.2 million, partially offset by a $10.6 million increase in other operating expenses.

Gross Margin

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 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 (other than service expansions)	938
Other	210
Gross margin for the year ended December 31, 2015	$179,088

The following is a narrative discussion of the significant items, which we believe is necessary to understand the information disclosed in the foregoing 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. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year OPT ≤ 90 Service.
- $1.4 million from a new service to the same industrial customer in Kent County, Delaware, that commenced on October 1, 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.

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- $334,000 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. This contract was subsequently amended to provide 55,580 Dts/d of service at a lower reservation rate through August 2020. Although the lower rate decreased gross margin by $437,000 for 2015, the extension of the contract at a higher volume generated additional gross margin of $771,000 for 2015. This service generated $2.3 million of gross margin in 2015 compared to $1.9 million of gross margin generated in 2014.
- $322,000 from two short-term contracts with the same industrial customer in New Castle County, Delaware, to provide an additional 10,000 Dts/d of OPT ≤ 90 Service transmission service from December 2014 to March 2015 and November 2015 to March 2016, respectively.
- $908,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.

Additional Revenue from GRIP in Florida

In 2015, FPU and Chesapeake Utilities' Florida division recorded $4.2 million in additional gross margin as a result of additional GRIP capital 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.

Other Operating Expenses

The increase in other 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 payroll and benefits 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; partially offset by:
- $1.5 million gain from the billing system settlement, which reduced other operating expenses for 2015.

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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.

2014 compared to 2013

Operating income for the Regulated Energy segment increased by $367,000 to $50.5 million for 2014, compared to 2013. An increase in gross margin of $20.1 million was partially offset by the $6.4 million asset impairment charge in 2014 related to the then uncertainty about the implementation of a customer billing system and an increase in other operating expenses of $13.3 million. Excluding the impairment charge, operating income increased by $6.8 million.

Gross Margin

Items contributing to the year-over-year increase of $20.1 million, or 14 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the year ended December 31, 2013	$145,820
Factors contributing to the gross margin increase for the year ended December 31, 2014:	
Margin from acquisitions	5,718
Service expansions	5,591
Additional revenue from GRIP in Florida	2,862
Other natural gas growth	2,671
Increased customer consumption—weather and other	1,432
Implementation of electric rates in Florida	1,269
Other	519
Gross margin for the year ended December 31, 2014	$165,882

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

Contributions from Acquisitions

Sandpiper generated $5.5 million of additional gross margin in 2014 due to the inclusion of a full year of operation (the acquisition of the operating assets of ESG by Sandpiper occurred in late May 2013). Also, the acquisition in December 2013 of certain operating assets of Fort Meade generated $174,000 of additional gross margin in 2014.

Service Expansions

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

- $2.1 million from long-term natural gas transmission services that commenced in November 2013 to industrial customers located in New Castle and Kent Counties, Delaware, which displaced short-term services provided to the same customers from May through October 2013.
- $1.9 million from a short-term contract with an existing industrial customer to provide an additional 50,000 Dts/d of natural gas transmission services from April 2014 to April 2015. This new service was subsequently extended to August 2014 to provide 55,580 Dts/d of service through August 2020. This short-term contract is expected to generate $2.2 million of gross margin in 2015.
- $1.1 million from other major service expansions completed in 2013 that facilitated new natural gas transmission and distribution services in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Indian River County, Florida.
- $463,000 from a new service to an industrial customer facility in Kent County, Delaware that commenced on October 1, 2014. This service required construction of new facilities, including approximately 5.5 miles of pipeline lateral and metering facilities, extending from Eastern Shore's mainline to the new industrial customer facility, and is expected to generate annual gross margin of $1.2 million to $1.8 million.

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Additional Revenue from GRIP in Florida
In 2014, FPU and Chesapeake Utilities' Florida division recorded $2.9 million in additional gross margin as a result of additional GRIP capital expenditures.
Other Natural Gas Growth
Increased gross margin from other natural gas growth was due primarily to the following:
- $2.0 million from natural gas customer growth in Florida due primarily to new services to commercial and industrial customers.
- $788,000 from a three percent increase in residential customers, as well as growth in commercial and industrial customers, in our Delmarva natural gas distribution operations.

Increased Customer Consumption—Weather and Other
In 2014, higher customer consumption due to colder temperatures on the Delmarva Peninsula and in Florida generated increased gross margin of approximately $1.1 million. Higher non-weather-related consumption generated additional gross margin of $322,000.
Implementation of Electric Rates in Florida
Our FPU electric distribution operation generated additional gross margin of $1.3 million as a result of implementing interim and full rates as part of its base rate case filing.
Other Operating Expenses
The increase in other operating expenses, excluding impairment charges, was due primarily to: (a) $3.3 million in higher payroll and benefits costs to support growth, and a change in our vacation policy in 2013; (b) $2.5 million in other operating expenses associated with Sandpiper's operations; (c) $2.6 million in higher depreciation, amortization, asset removal costs and property taxes associated with capital investments to support growth and maintain system integrity; (d) $2.2 million in higher costs associated with facilities maintenance and service contractors; (e) the absence in 2014 of a one-time credit of $1.5 million in 2013 associated with the City of Marianna litigation cost recovery; and (f) $1.0 million of increased accruals for incentive bonuses as a result of strong financial performance. These increases in other operating expenses were partially offset by the non-recurrence of a sales tax expense of $726,000 in 2013 recorded in conjunction with the ESG acquisition.

UNREGULATED ENERGY

For the Year Ended December 31, (in thousands)	2015	2014	Increase (decrease)	2014	2013	Increase (decrease)
Revenue	$162,108	$184,961	$(22,853)	$184,961	$166,723	$18,238
Cost of sales	101,791	137,081	(35,290)	137,081	121,348	15,733
Gross margin	60,317	47,880	12,437	47,880	45,375	2,505
Operations & maintenance	36,536	30,197	6,339	30,197	26,657	3,540
Asset impairment charges	—	432	(432)	432	—	432
Depreciation & amortization	5,679	3,994	1,685	3,994	3,686	308
Other taxes	1,747	1,534	213	1,534	2,679	(1,145)
Other operating expenses	43,962	36,157	7,805	36,157	33,022	3,135
Operating Income	$16,355	$11,723	$4,632	$11,723	$12,353	$(630)

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 primarily due to an increase in gross margin of $12.4 million and the absence of $432,000 in asset impairment charges of goodwill and intangible assets recorded in 2014, offset by an increase in other operating expenses of $8.2 million.

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Gross Margin

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:	
Increase in retail propane margins	8,930
Margin generated by Aspire Energy	6,345
Decreased customer consumption - weather and other	(1,792)
Propane Wholesale Marketing	(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, which we believe is necessary to understand the information disclosed in the foregoing 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.

Margin generated by Aspire Energy

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

Decreased Customer Consumption - Weather and Other

Reduced consumption decreased gross margin 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 Propane Wholesale Marketing Results

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.

Other Operating Expenses

Other operating expenses increased by $7.8 million due primarily to $5.8 million of other operating expenses incurred by Aspire Energy. The remaining increase in other operating expenses was due primarily to:

- $1.4 million in higher payroll and benefits expense 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.

2014 Compared to 2013

Operating income for the Unregulated Energy segment was $11.7 million, a decrease of $630,000, compared to 2013. An increase in gross margin of $2.5 million was more than offset by $432,000 in asset impairment charges for goodwill and intangible assets related to the 2013 acquisition of certain assets by Austin Cox and an increase in other operating expenses of $2.7 million.

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Gross Margin

Items contributing to the year-over-year increase of $2.5 million, or six percent, in gross margin were as follows:

(in thousands)	
Gross margin for the year ended December 31, 2013	$45,375
Factors contributing to the gross margin increase for the year ended December 31, 2014:	
Increased customer consumption—weather and other	1,412
Increased wholesale propane sales	1,391
Decrease in retail propane margins	(356)
Other	58
Gross margin for the year ended December 31, 2014	$47,880

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

Increased Customer Consumption—Weather and Other

Higher customer consumption due to colder temperatures during 2014 generated an additional gross margin of $1.7 million. This was partially offset by lower non-weather related consumption, which reduced gross margin by $279,000.

Increased Wholesale Propane Sales

An increase in wholesale propane sales generated additional gross margin of $1.4 million due primarily to the supply agreement entered into in May 2013 with an affiliate of ESG.

Decrease in Retail Propane Margins

Lower retail propane margins for our Delmarva propane distribution operation decreased gross margin by $2.3 million. A significant increase in wholesale prices in late 2013 and early 2014 increased our propane inventory cost in 2014 and retail margins reverted to more normal levels. In addition, a rapid decline in wholesale prices in late 2014 resulted in a lower-of-cost-or-market propane inventory valuation adjustment and our decision to discontinue hedge accounting on swap agreements to recognize the expected losses on those agreements in current years' earnings. The lower-of-cost-or-market adjustment and the discontinuation of hedge accounting decreased retail margins per gallon in 2014.

This decrease was partially offset by $1.9 million in higher retail propane margins in Florida, as local market conditions enabled the Florida propane distribution operations to maintain strong margins on sales despite volatility in propane supply costs. The propane retail price per gallon is subject to various market conditions, including competition with other propane suppliers and the availability and price of alternative energy sources. The propane retail price per gallon may fluctuate based on changes in demand, supply and other energy commodity prices.

Other Operating Expenses

The increase in other operating expenses, excluding impairment charges, was due primarily to: (a) $1.9 million in higher payroll and benefits costs due to increased seasonal overtime and additional resources to support growth; (b) $897,000 in additional expenses associated with serving newly acquired customers; and (c) $540,000 in higher costs associated with facilities maintenance. These increases were partially offset by the non-recurrence of a contingency accrual of $990,000 in 2013 related to taxes other than income.

GAIN FROM SALE OF BUSINESSES

On October 1, 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 2013.

OTHER INCOME

Other income for 2015, 2014 and 2013 was $293,000, $101,000 and $372,000, 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

2015 Compared to 2014

Interest charges for 2015 increased by approximately $524,000, or six percent, compared to 2014. The increase in interest charges 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.

2014 Compared to 2013

Interest expense for 2014 increased by approximately $1.2 million, or 15 percent, compared to the same period in 2013. The increase in interest expense was attributable primarily to the Senior Notes issued in December 2013 and May 2014.

INCOME TAXES

2015 Compared to 2014

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

2014 Compared to 2013

Income tax expense was $23.9 million in 2014, compared to $22.1 million in 2013. Our effective tax rate was 39.9 percent in 2014, compared to 40.2 percent in 2013.

LIQUIDITY AND CAPITAL RESOURCES

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

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, including acquisitions, during 2015, 2014 and 2013 were $195.2 million, $98.1 million and $108.0 million, respectively. The significant increase in our capital expenditures in 2015 compared to 2014 and 2013, resulted from the acquisition of Gatherco ($52.5 million net of cash acquired), additional capital investment in the Florida GRIP ($32.8 million) and Eight Flags' construction of the CHP plant in Florida ($24.7 million).

We have budgeted $179.3 million for capital expenditures in 2016. The following table shows the 2016 capital expenditure budget by segment and by business line:

(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$73,285
Natural gas transmission	66,938
Electric distribution	7,566
Total Regulated Energy	147,789
Unregulated Energy:	
Propane distribution	11,141
Other unregulated energy	13,504
Total Unregulated Energy	24,645
Other:	
Other corporate and common	6,871
Total Other	6,871
Total 2016 Capital Expenditures	$179,305

The 2016 budget is a significant increase over prior years’ average annual level of capital expenditures, excluding the Gatherco acquisition, due to a shifting in the capital outlay from 2015 to 2016 for several ongoing projects, including but not limited to the Eight Flags' CHP plant, Eastern Shore's White Oak mainline expansion and system reliability projects; additional expansions of our natural gas distribution and transmission systems; continued natural gas infrastructure improvement activities as well as expenditures for continued replacement under the GRIP in our Florida natural gas distribution operations; replacement of several facilities and systems; and other strategic initiatives and investments expected in 2016. In addition, $30.0 million is included in the 2016 capital budget for projects that are in the early development stage.

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.

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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 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, 2015 and 2014:

	December 31, 2015			December 31, 2014		
(in thousands)						
Long-term debt, net of current maturities	$149,340	29	%	$158,486	35	%
Stockholders' equity	358,138	71	%	300,322	65	%
Total capitalization, excluding short-term borrowings	$507,478	100	%	$458,808	100	%

	December 31, 2015			December 31, 2014		
(in thousands)						
Short-term debt	$173,397	25	%	$88,231	16	%
Long-term debt, including current maturities	158,491	23	%	167,595	30	%
Stockholders' equity	358,138	52	%	300,322	54	%
Total capitalization, including short-term borrowings	$690,026	100	%	$556,148	100	%

Included in the long-term debt balance at December 31, 2015 was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($3.5 million net of current maturities and $4.8 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, 2015, 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, 2015, $146.6 million of Chesapeake Utilities' cumulative consolidated net income and $78.7 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 52 percent and 54 percent during the past three years. Our equity as a percent of total capital declined in 2015 as we financed several large revenue generating capital projects with short-term borrowings. As we continue to construct these projects in 2016, the ratio of equity to total capitalization, including short-term borrowings, will further decline temporarily.

As described below under "Short-term Borrowings", we entered into a new Revolver with the Lenders on October 8, 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 private placement Shelf Agreement with Prudential that is further described below under "Shelf Agreement."

We will seek to align, as much as feasible, any such 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

On October 8, 2015, we entered into a committed Shelf Agreement with Prudential and other purchasers that may become a party to the Shelf Agreement. Under the terms of the Shelf Agreement, we may request that Prudential purchase, over the next three years, 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 and its affiliates are 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 that the proceeds from the sale of any series of Shelf Notes will be used for general corporate purposes, including the refinancing of short-term borrowings and/or repayment of outstanding indebtedness and financing of 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.

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Short-term Borrowings

Our outstanding short-term borrowings at December 31, 2015 and 2014 were $173.4 million and $88.2 million, respectively, at the weighted average interest rates of 1.30 percent and 1.15 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. During 2015, we had four unsecured bank credit facilities with three financial institutions totaling $170.0 million in total available credit. In addition, beginning in October of 2015, we also had additional short-term debt capacity available under a Revolver with five participating Lenders totaling $150.0 million. The terms of the Revolver are described in further detail below. We also had access to two credit facilities, which totaled $40.0 million; however, these credit facilities expired on October 31, 2015. These facilities were not renewed given the addition of the new Revolver. None of the unsecured bank lines of credit requires compensating balances. Our Board of Directors previously authorized us to borrow up to $200.0 million of short-term borrowings, as necessary. On February 24, 2016, the Board of Directors increased this limit to $275.0 million.

On October 8, 2015, we entered into the Credit Agreement with the Lenders to provide a $150.0 million Revolver for five years subject to the terms and conditions as specified. 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 may 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. At December 31, 2015, we had borrowed $35.0 million under the Revolver.

Our outstanding short-term borrowings at December 31, 2015 and 2014 included $4.6 million and $2.2 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, 2015, we had issued $5.6 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, 2015 and 2014 were $168.8 million and $86.0 million, respectively. Short term borrowings were as follows during 2015, 2014 and 2013:

(in thousands)	2015	2014	2013
Average borrowings	$102,062	$68,928	$67,367
Weighted average interest rate	1.22%	1.28%	1.34%
Maximum month-end borrowings	$168,757	$86,040	$102,554

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the years ended December 31, 2015, 2014 and 2013:

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Net cash provided by (used in):			
Operating activities	$105,142	$79,284	$72,931
Investing activities	(165,558)	(86,586)	(114,781)
Financing activities	58,697	8,520	41,845
Net increase (decrease) in cash and cash equivalents	(1,719)	1,218	(5)
Cash and cash equivalents—beginning of period	4,574	3,356	3,361

Cash and cash equivalents—end of period	$2,855	$4,574	$3,356

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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 2015 and 2014, net cash provided by operating activities was $105.1 million and $79.3 million, respectively, resulting in an increase in cash flows of $25.8 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 (approved by the President of the United States in December 2014), 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 $6.4 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.

During 2014 and 2013, net cash provided by operating activities was $79.3 million and $72.9 million, respectively, resulting in an increase in cash flows of $6.4 million in 2014. Significant operating activities generating the cash flow change were as follows:

- Net income, adjusted for non-cash adjustments and reconciling activities, increased cash flows by $15.1 million.
- Changes in net accounts receivable and payable increased cash flows by $15.1 million, due primarily to the timing of the collections and payments associated with trading contracts entered into by our propane wholesale and marketing subsidiary.
- Net cash flows from changes in inventories increased by approximately $8.7 million as a result of lower commodity prices, which decreased the carrying value of our inventory.
- These increases in operating cash flow were partially offset by a decrease in cash flows from changes in net regulatory assets and liabilities of $13.3 million, due primarily to a change in fuel cost collected through fuel cost recovery mechanisms and additional piping and conversion costs during 2014, which will be recovered through future rates.
- Higher net income tax payments decreased cash flows by $18.2 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $165.6 million and $86.6 million for 2015 and 2014, respectively, resulting in a decrease in cash flows of $79.0 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 $47.5 million.
- 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 on April 1, 2015. In addition to the net cash consideration, we also issued 592,970 shares of our common stock, which had no cash flow impact.

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Net cash used in investing activities totaled $86.6 million and $114.8 million for 2014 and 2013, respectively, resulting in an increase in cash flows of $28.2 million. Significant investing activities contributing to the cash flow change were as follows:

- We paid $20.2 million for various acquisitions in 2013. There were no corresponding transactions during 2014.
- We received $10.2 million associated with the disposition of BravePoint in October 2014, compared to $2.3 million received from the sale of equity securities during 2013.

Cash Flows Provided by Financing Activities

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 Series B 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 Series B Notes in May 2014.

Net cash provided by financing activities totaled $8.5 million and $41.8 million for 2014 and 2013, respectively, resulting in a decrease of $33.3 million in 2014. Significant financing activities generating the cash flow change were as follows:

- Net borrowings/repayments under the line of credit agreements decreased cash flows by $62.6 million. The proceeds from the issuance of the Series B Notes were used to repay borrowings under line of credit agreements.
- Net proceeds from and repayments of long-term debt increased cash flows by $28.2 million due primarily to the $50.0 million issuance of the Series B Notes in May 2014, compared to $20.0 million from the issuance of the Series A Notes in December 2013.

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CONTRACTUAL OBLIGATIONS

We have the following contractual obligations and other commercial commitments as of December 31, 2015:

	Payments Due by Period				
Contractual Obligations	Less than 1 year	1 — 3 years	3 — 5 years	More than 5 years	Total
(in thousands)					
Long-term debt [1]	$7,798	$18,669	$26,226	$101,000	$153,693
Operating leases [2]	1,270	1,133	697	2,215	5,315
Capital leases [2] [3]	1,353	2,852	620	—	4,825
Purchase obligations [4]					
Transmission capacity	27,750	55,067	44,907	100,133	227,857
Storage — Natural Gas	1,482	2,502	1,365	641	5,990
Commodities	27,272	6,452	1,128	—	34,852
Electric supply	15,792	32,812	17,020	—	65,624
Unfunded benefits [5]	407	731	680	1,707	3,525
Funded benefits [6]	2,091	4	—	3,608	5,703
Total Contractual Obligations	$85,215	$120,222	$92,643	$209,304	$507,384

(1) This represents principal payments on long-term debt. See Item 8, Financial Statements and Supplementary Data, Note 12, Long-Term Debt, for additional discussion of this item. The expected interest payments on long-term debt are $8.2 million, $15.0 million, $12.7 million and $21.9 million, respectively, for the periods indicated above. Expected interest payments for all periods total $58.0 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 4, Acquisitions and Disposition, for further information.

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

(5) We have recorded long-term liabilities of $3.5 million at December 31, 2015 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.

(6) We have recorded long-term liabilities of $26.0 million at December 31, 2015 for two qualified, defined benefit pension plans. The assets funding these plans are in a separate trust and are not our considered assets of ours or included in our balance sheets. The Contractual Obligations table above includes $2.1 million, reflecting the expected payments we will make to the trust funds in 2015. 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 Plans, for further information on the plans. Additionally, the Contractual Obligations table includes deferred compensation obligations totaling $3.6 million, funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the Balance Sheet. 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 its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at December 31, 2015 was $45.6 million, with the guarantees expiring on various dates through December 29, 2016.

We have issued letters of credit totaling $5.6 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 31, 2016. There have been no draws on these letters of credit as of December 31, 2015. 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.

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

INTEREST RATE RISK

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Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate Senior Notes and $8.0 million of secured debt. All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities but excluding a capital lease obligation was, $153.7 million at December 31, 2015, as compared to a fair value of $165.1 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 with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowings based in part on the fluctuation in interest rates.

COMMODITY PRICE RISK RELATED TO REGULATED ENERGY SEGMENT

We have entered into agreements with various wholesale suppliers to purchase natural gas and electricity for resale to our customers. Purchases under these contracts either do not meet the definition of derivatives or are considered “normal purchases and sales” and are accounted for on an accrual basis. For all of our regulated businesses that sell natural gas or electricity to end-use customers, 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 that we recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers.

COMMODITY PRICE RISK RELATED TO UNREGULATED ENERGY SEGMENT

Sharp is 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 6.5 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. Purchases under forward contracts are typically considered “normal purchases and sales” and are accounted for on an accrual basis. 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 volume requirements and we continue to seek out new producers with which to contract in order to fulfill our natural gas purchase requirements.

Commodity Contracts

Xeron is a party to natural gas liquids forward contracts, which are primarily propane contracts, with various third parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are typically settled financially without taking physical delivery of propane. Xeron also enters into futures contracts that are traded on the InterContinentalExchange. In certain cases, the futures contracts are settled by the payment or receipt of a net amount equal to the difference between the current market price of the futures contract and the original contract price; however, they may also be settled by physical receipt or delivery of propane. The forward and futures contracts are entered into for trading and wholesale marketing purposes.

PESCO is party to natural gas futures contracts. These contracts provide PESCO with the right to purchase natural gas at a fixed price at future dates. At the 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 and the credit risk of counterparties, 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.
Additional information about our derivative instruments is disclosed in Item 8, Financial Statements and Supplementary Data (See Note 7: Derivative Instruments, in the Consolidated Financial Statements).

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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 business operations. To compensate for fluctuations in propane gas prices, we adjust propane sales prices to the extent allowed by the market.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation
We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation (the “Company”) as of December 31, 2015 and 2014, 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, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015, 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, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 26, 2016 expressed an unqualified opinion.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
February 26, 2016

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Income

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands, except shares and per share data)			
Operating Revenues			
Regulated Energy	$301,902	$300,442	$264,637
Unregulated Energy	162,108	184,961	166,723
Other businesses and eliminations	(4,766)	13,431	12,946
Total operating revenues	459,244	498,834	444,306
Operating Expenses			
Regulated energy cost of sales	122,814	134,560	118,818
Unregulated energy and other cost of sales	97,228	143,556	126,017
Operations	107,562	102,197	91,452
Maintenance	11,803	9,706	7,509
(Gain from a settlement)/asset impairment charges	(1,500)	6,881	—
Depreciation and amortization	29,972	26,316	23,965
Other taxes	13,607	13,339	13,811
Total operating expenses	381,486	436,555	381,572
Operating Income	77,758	62,279	62,734
Gains from sales of businesses	—	7,139	—
Other income, net of other expenses	293	101	372
Interest charges	10,006	9,482	8,234
Income Before Income Taxes	68,045	60,037	54,872
Income taxes	26,905	23,945	22,085
Net Income	$41,140	$36,092	$32,787
Weighted Average Common Shares Outstanding:			
Basic	15,094,423	14,551,308	14,430,962
Diluted	15,143,373	14,604,944	14,543,446
Earnings Per Share of Common Stock:			
Basic	$2.73	$2.48	$2.27
Diluted	$2.72	$2.47	$2.26
Cash Dividends Declared Per Share of Common Stock	$1.1325	$1.0667	$1.0133

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Comprehensive Income

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Net Income	$41,140	$36,092	$32,787
Other Comprehensive Income (Loss), net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of $(27), $(24) and $(24), respectively	(40)	(34)	(36)
Net gain (loss), net of tax of $73, $(1,997) and $1,673, respectively	103	(3,076)	2,565
Cash Flow Hedges, net of tax:			
Unrealized loss on commodity contract cash flow hedges, net of tax of $(150), $(22) and $0, respectively	(227)	(33)	—
Total Other Comprehensive Income (Loss)	(164)	(3,143)	2,529
Comprehensive Income	$40,976	$32,949	$35,316

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

Assets	As of December 31, 2015	2014
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	$842,756	$766,855
Unregulated energy	145,734	84,773
Other businesses and eliminations	18,999	18,497
Total property, plant and equipment	1,007,489	870,125
Less: Accumulated depreciation and amortization	(215,313)	(193,369)
Plus: Construction work in progress	62,774	13,006
Net property, plant and equipment	854,950	689,762
Current Assets		
Cash and cash equivalents	2,855	4,574
Accounts receivable (less allowance for uncollectible accounts of $909 and $1,120, respectively)	41,007	53,300
Accrued revenue	12,452	13,617
Propane inventory, at average cost	6,619	7,250
Other inventory, at average cost	3,803	3,699
Regulatory assets	8,268	8,967
Storage gas prepayments	3,410	4,258
Income taxes receivable	24,950	18,806
Deferred income taxes	831	—
Prepaid expenses	7,146	6,652
Mark-to-market energy assets	153	1,055
Other current assets	1,044	195
Total current assets	112,538	122,373
Deferred Charges and Other Assets		
Goodwill	14,548	4,952
Other intangible assets, net	2,222	2,404
Investments, at fair value	3,644	3,678
Regulatory assets	77,519	78,136
Receivables and other deferred charges	3,165	3,164
Total deferred charges and other assets	101,098	92,334
Total Assets	$1,068,586	$904,469

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

	As of December 31,	
Capitalization and Liabilities	2015	2014
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000)	$7,432	$7,100
Additional paid-in capital	190,311	156,581
Retained earnings	166,235	142,317
Accumulated other comprehensive loss	(5,840)	(5,676)
Deferred compensation obligation	1,883	1,258
Treasury stock	(1,883)	(1,258)
Total stockholders' equity	358,138	300,322
Long-term debt, net of current maturities	149,340	158,486
Total capitalization	507,478	458,808
Current Liabilities		
Current portion of long-term debt	9,151	9,109
Short-term borrowing	173,397	88,231
Accounts payable	39,300	44,610
Customer deposits and refunds	27,173	25,197
Accrued interest	1,311	1,352
Dividends payable	4,390	3,939
Deferred income taxes	—	832
Accrued compensation	10,014	10,076
Regulatory liabilities	7,365	3,268
Mark-to-market energy liabilities	433	1,018
Other accrued liabilities	7,059	6,603
Total current liabilities	279,593	194,235
Deferred Credits and Other Liabilities		
Deferred income taxes	193,431	160,232
Regulatory liabilities	43,064	43,419
Environmental liabilities	8,942	8,923
Other pension and benefit costs	33,481	35,027
Deferred investment tax credits and other liabilities	2,597	3,825
Total deferred credits and other liabilities	281,515	251,426
Other commitments and contingencies (Note 19 and 20)		
Total Capitalization and Liabilities	$1,068,586	$904,469

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Operating Activities			
Net Income	$41,140	$36,092	$32,787
Adjustments to reconcile net income to net operating cash:			
Goodwill & long-lived asset impairment	—	6,881	—
Depreciation and amortization	29,972	26,316	23,965
Depreciation and accretion included in other costs	6,978	6,577	6,123
Deferred income taxes, net	20,520	22,235	14,860
Realized gain on sale of assets/investments	(340)	(7,293)	(854)
Unrealized loss (gain) on investments/commodity contracts	96	501	(706)
Employee benefits and compensation	1,235	684	1,119
Share-based compensation	1,937	1,958	1,631
Other, net	47	3	(28)
Changes in assets and liabilities:			
Accounts receivable and accrued revenue	17,097	20,683	(21,244)
Propane inventory, storage gas and other inventory	1,527	4,177	(4,492)
Regulatory assets/liabilities, net	3,883	(11,014)	2,328
Prepaid expenses and other current assets	(759)	(699)	(1,064)
Accounts payable and other accrued liabilities	(10,897)	(8,047)	18,824
Income taxes receivable	(4,967)	(15,936)	2,311
Customer deposits and refunds	1,976	(927)	(3,362)
Accrued compensation	(331)	37	837
Other assets and liabilities, net	(3,972)	(2,944)	(104)
Net cash provided by operating activities	105,142	79,284	72,931
Investing Activities			
Property, plant and equipment expenditures	(144,618)	(97,164)	(97,120)
Change in intangibles	—	14	—
Proceeds from sale of assets	164	10,797	199
Proceeds from sale of investments	—	—	2,300
Acquisitions, net of cash acquired	(20,930)	—	(20,201)
Environmental expenditures	(174)	(233)	41
Net cash used by investing activities	(165,558)	(86,586)	(114,781)
Financing Activities			
Common stock dividends	(15,924)	(13,887)	(13,081)
Issuance (Purchase) of stock for Dividend Reinvestment Plan	813	(165)	(1,342)
Change in cash overdrafts due to outstanding checks	2,450	(921)	(1,666)
Net borrowing (repayment) under line of credit agreements	82,178	(16,513)	46,133
Proceeds from issuance of long-term debt	—	49,975	26,766
Repayment of long-term debt and capital lease obligation	(10,820)	(9,969)	(14,957)
Other	—	—	(8)
Net cash provided by financing activities	58,697	8,520	41,845
Net (Decrease) Increase in Cash and Cash Equivalents	(1,719)	1,218	(5)
Cash and Cash Equivalents — Beginning of Period	4,574	3,356	3,361

Cash and Cash Equivalents — End of Period	$2,855	$4,574	$3,356

Supplemental Cash Flow Disclosures (see Note 6)

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

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Stockholders' Equity

(in thousands, except shares and per share data)	Common Stock Number of Shares[1]	Common Stock Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2012	14,396,248	$4,671	$150,750	$106,239	$ (5,062)	$ 982	$(982)	$256,598
Net Income	—	—	—	32,787	—	—	—	32,787
Other comprehensive loss	—	—	—	—	2,529	—	—	2,529
Dividend declared ($1.0133 per share)	—	—	(6)	(14,752)	—	—	—	(14,758)
Conversion of Debentures	26,075	8	287	—	—	—	—	295
Share-based compensation and tax benefit [2] [3]	35,022	12	1,310	—	—	—	—	1,322
Treasury stock activities[1]	—	—	—	—	—	142	(142)	—
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)
Dividend declared ($1.0667per 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 [2] [3]	40,686	13	1,876	—	—	—	—	1,889
Stock split in the form of stock dividend	—	2,365	—	(2,374)	—	—	—	(9)
Treasury stock activities[1]	—	—	—	—	—	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)
Dividend 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 [(2)] [(3)]	45,703	22	1,640	—	—	—	—	1,662
Treasury stock activities[(1)]	—	—	—	—	—	625	(625)	—
Balance at December 31, 2015	15,270,659	$7,432	$190,311	$166,235	$ (5,840)	$ 1,883	$(1,883)	$358,138

(1) Includes 70,631, 57,382 and 51,743 shares at December 31, 2015, 2014 and 2013, respectively, held in a Rabbi Trust related to our Non-Qualified Deferred Compensation Plan.

(2) Includes amounts for shares issued for directors' compensation.

(3) The shares issued under the SICP are net of shares withheld for employee taxes. For 2015, 2014 and 2013, we withheld 12,620, 12,687 and 15,617 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 wholesale marketing operation, which markets propane 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 and Maryland and other states; and (d) our natural gas supply, gathering and processing operation in central and eastern Ohio.

Our consolidated financial statements as of December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013 have been prepared in compliance with the rules and regulations of the SEC and GAAP. 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 reported on subsequent events through the date of issuance of these consolidated financial statements.

We reclassified certain amounts in the consolidated balance sheet as of December 31, 2014 and consolidated statements of cash flows for the years ended December 31, 2014 and 2013 to conform to the current year’s presentation. These reclassifications are considered immaterial to the overall presentation of our consolidated financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of 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.

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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 against income as incurred, and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of property owned by the unregulated businesses, the gain or loss, net of salvage value, is charged to income. Upon retirement or disposition of property within the regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. A summary of property, plant and equipment by classification as of December 31, 2015 and 2014 is provided in the following table:

	As of December 31,	
(in thousands)	2015	2014
Property, plant and equipment		
Regulated Energy		
Natural gas distribution – Delmarva	$207,127	$193,071
Natural gas distribution – Florida	286,538	234,344
Natural gas transmission – Delmarva	249,274	243,560
Natural gas transmission – Florida	20,291	18,240
Electric distribution – Florida	79,526	77,640
Unregulated Energy		
Propane distribution – Delmarva	66,403	61,390
Propane distribution – Florida	24,589	23,142
Other unregulated natural gas services – Ohio	54,607	—
Other unregulated energy	135	241
Other	18,999	18,497
Total property, plant and equipment	1,007,489	870,125
Less: Accumulated depreciation and amortization	(215,313)	(193,369)
Plus: Construction work in progress	62,774	13,006
Net property, plant and equipment	$854,950	$689,762

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, 2015 and 2014, there were $1.7 million and $813,000, respectively, of non-refunded contributions or advances reducing 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, 2015, 2014, and 2013, we recorded $38,000, $58,000, and $131,000, respectively, of AFUDC, all of which were related to short-term debt and reflected as a reduction of interest charges.

Asset Used in Leases

Property, plant and equipment for the Florida natural gas transmission operation included $1.4 million of assets, at December 31, 2015 and 2014, 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 $507,000 and $435,000, at December 31, 2015 and 2014, respectively.

Capital Lease Asset

Property, plant and equipment for our Delmarva natural gas distribution operation included a capital lease asset of $4.8 million and $6.1 million, net of amortization, at December 31, 2015 and 2014, respectively, related to Sandpiper's capacity, supply and operating agreement. See Note 20, Other Commitments and Contingencies for additional information. At December 31, 2015 and 2014, accumulated amortization for this capital lease asset was $2.3 million and $996,000, respectively. For the years ended December 31, 2015 and 2014, we recorded $1.3 million and $848,000, 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, 2015 and 2014, 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. This 16-mile pipeline was placed in service in December 2012. Accumulated depreciation for this pipeline totaled $806,000 and $584,000, at December 31, 2015 and 2014, respectively.

Other 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.

On May 29, 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 remaining $19,000 included in the Unregulated Energy segment. We may also receive $750,000 in additional cash and discounts from future services; however, the receipt or retention of additional cash and future discounts is contingent upon engaging this vendor to provide agreed-upon services over the next five years.

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 during the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Natural gas distribution – Delmarva	2.4%	2.5%	2.5%
Natural gas distribution – Florida	2.9%	2.9%	3.4%
Natural gas transmission – Delmarva	2.7%	2.7%	2.7%
Natural gas transmission – Florida	4.0%	4.0%	4.8%
Electric distribution – Florida	3.5%	3.8%	3.6%

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During 2015, the Florida PSC approved new depreciation rates for our Florida electric distribution operations (see Note 18, Rates and Other Regulatory Activities, for additional information), which lowered its depreciation rates effective January 1, 2015.

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
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, 2015, 2014 and 2013, we reported $7.0 million, $6.6 million and $6.1 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.

At December 31, 2015 and 2014, 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.

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	As of December 31,	
	2015	2014
(in thousands)		
Regulatory Assets		
Under-recovered purchased fuel and conservation cost recovery (1)	$4,598	$6,865
Under-recovered GRIP revenue (1)	3,091	1,491
Deferred post retirement benefits (2)	19,479	19,762
Deferred conversion and development costs (1)	5,729	3,745
Environmental regulatory assets and expenditures (3)	4,158	4,452
Acquisition adjustment (4)	43,735	45,607
Loss on reacquired debt (5)	1,259	1,372
Other	3,738	3,809
Total Regulatory Assets	$85,787	$87,103
Regulatory Liabilities		
Self insurance (6)	$1,031	$1,003
Over-recovered purchased fuel and conservation cost recovery (1)	6,994	2,936
Storm reserve (6)	2,973	2,982
Accrued asset removal cost (7)	39,206	39,583
Other	225	183
Total Regulatory Liabilities	$50,429	$46,687

(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 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.

(3) 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.

(4) 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.

(5) 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.

(6) We have self-insurance and storm reserves that allow us to collect through rates amounts to be used against general claims, storm restoration costs and other losses as they are incurred.

(7) In accordance with typical regulatory policy, our depreciation rates are comprised of two components: historical cost and the estimated cost of removal, net of estimated salvage, of certain regulated properties. We collect these costs in base rates through depreciation expense with a corresponding credit to accumulated depreciation. Because the accumulated estimated removal costs meet the requirements of authoritative guidance related to regulated operations, we have accounted for them as a regulatory liability and have reclassified them from accumulated depreciation to accumulated removal costs in our consolidated balance sheets.

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 provisions of ASC Topic 980, Regulated Operations, continue to apply to our regulated operations and that the recovery of our regulatory assets is probable.

Operating Revenues

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.

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 for Aspire Energy, transportation costs to transport propane purchases to our storage facilities 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. At December 31, 2014, we reduced our propane inventory value by $681,000 to reflect the lower-of-cost-or-market adjustment. There was no lower-of-cost-or-market adjustment during 2015.

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Goodwill and Other Intangible Assets

Goodwill is not amortized but is tested for impairment at least annually. In addition, 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. Other intangible assets are amortized on a straight-line basis over their estimated economic useful lives. Please refer to Note 10, Goodwill and Other Intangible Assets, for additional discussion of this subject.

We test goodwill for impairment at least annually in December of each year. The testing of goodwill for 2015 indicated no goodwill impairment. There was a $237,000 goodwill impairment loss associated with the Austin Cox acquisition for 2014. Additionally, in 2014, we recorded a $175,000 impairment loss on an intangible asset related to a non-compete agreement associated with Austin Cox.

Other Deferred Charges

Other deferred charges include discount, premium and issuance costs associated with long-term debt. Debt issuance costs are deferred and then are amortized to interest expense over the original lives of the respective debt issuances.

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 $19,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $19,000. A 0.25 percent change in the rate of return could change our annual pension cost by approximately $126,000 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.

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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 on 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 their customers. Purchases under these contracts 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 operation may enter into derivative transactions, such as swaps, put options and call options in order to mitigate the impact of wholesale price fluctuations on its inventory valuation and future purchase commitments.

Our natural gas marketing operation may also enter into cash flow hedges in order to mitigate the impact of fluctuations in its margins. PESCO enters into natural gas futures contracts associated with the purchase and 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 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 propane inventory. 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 does not meet the accounting requirements of a hedge, it is recorded at fair value with the gain or loss being recorded in earnings.

FASB Statements and Other Authoritative Pronouncements

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. On July 9, 2015, the FASB affirmed its proposal to defer the implementation of this standard by one year. For public entities, this standard is effective for 2018 interim and annual financial statements. We are assessing the impact this standard may have on our financial position and results of operations.

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 is effective for our interim and annual financial statements issued beginning January 1, 2016. Early adoption is permitted for financial statements that have not been previously issued. As of December 31, 2015, we had $358,000 of unamortized debt issuance costs included in the accompanying consolidated balance sheets. Upon adoption of ASU 2015-03, this will be presented as a deduction from long-term debt, net of current maturities.

Customer's Accounting for Fees Paid in a Cloud Computing Arrangement (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 guidance, 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. The new guidance is effective for us beginning January 1, 2016, and may be applied either prospectively or retrospectively, with early adoption permitted. We are assessing the impact this standard will have, but anticipate the adoption of this standard will not have a material impact on our financial position, or results of operations.

Inventory (ASC 330) - In July 2015, the FASB issued ASU 2015-11, 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

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associated with completion, disposal and transportation. ASU 2015-11 will be effective for our interim and annual financial statements issued beginning January 1, 2017; however, early adoption is permitted. The standard is to be adopted on a prospective basis. We are assessing the potential effects this standard may have on our consolidated financial statements.

Debt Issuance Costs (ASC 835-30) - In August 2015, the FASB issued ASU 2015-15, Simplifying the Presentation 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 is effective for our interim and annual financial statements issued beginning January 1, 2016. Early adoption is permitted for financial statements that have not been previously issued. This standard is not expected to have a material impact on our financial position and results of operation.

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. The new guidance requires that the cumulative impact of a measurement period adjustment (including the impact of prior periods) be recognized in the reporting period in which the adjustment is identified. ASU 2015-16 will be effective for our interim and annual financial statements issued beginning January 1, 2016 and is to be adopted on a prospective basis. Early adoption is permitted for financial statements that have not been previously issued. We are assessing the impact this standard may have on our financial position and results of operation.

Balance Sheet Classification of Deferred 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. ASU 2015-17 will be effective for our annual financial statements beginning January 1, 2017 and for our interim financial statements beginning January 1, 2018; however, early adoption is permitted. As these are changes in the balance sheet classification only, there will no impact on our financial position or results of operation.

3. EARNINGS PER SHARE

Basic earnings per share are computed by dividing income available for common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted earnings per share are computed by dividing income available for common stockholders by the weighted average number of shares of common stock outstanding during the period adjusted for the exercise and/or conversion of all potentially dilutive securities, such as convertible debt and share-based compensation. The calculations of both basic and diluted earnings per share are presented in the following table.

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands, except shares and per share data)			
Calculation of Basic Earnings Per Share:			
Net Income	$41,140	$36,092	$32,787
Weighted average shares outstanding	15,094,423	14,551,308	14,430,962
Basic Earnings Per Share	$2.73	$2.48	$2.27
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income	$41,140	$36,092	$32,787
Effect of 8.25% Convertible debentures	—	—	43
Adjusted numerator — Diluted	$41,140	$36,092	$32,830

Reconciliation of Denominator:			
Weighted shares outstanding — Basic	15,094,423	14,551,308	14,430,962
Effect of dilutive securities:			
Share-based Compensation	48,950	53,636	37,866
8.25% Convertible debentures [1]	—	—	74,618
Adjusted denominator — Diluted	15,143,373	14,604,944	14,543,446
Diluted Earnings Per Share	$2.72	$2.47	$2.26

[1] As of March 1, 2014, we no longer have any outstanding convertible debentures.

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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.

4. ACQUISITIONS AND DISPOSITION

Gatherco Acquisition

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. Aspire Energy is an unregulated natural gas infrastructure company with approximately 2,500 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 Consumers Gas Cooperative which together serve more than 20,000 end-use customers. Aspire Energy primarily sources gas from 300 conventional producers and provides gathering and processing services necessary to maintain quality and reliability to its wholesale markets.

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 provides 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 over the next five years.

We incurred $1.3 million in transaction costs associated with this merger, $514,000 of which was expensed during the year ended December 31, 2015. Transaction costs are included in operations expense in the accompanying consolidated statements of income. The revenue and net income from this acquisition for the year ended December 31, 2015, included in our consolidated statements of income, were $16.7 million and $312,000, respectively. The 2015 financial results of Aspire Energy have had a minimal impact on our earnings per share in 2015, because the merger was completed after the first quarter of 2015, and Ohio experienced warmer than normal weather during the fourth quarter of 2015. The first and fourth quarters include key winter months, which have historically produced a significant portion of Gatherco's annual earnings. This acquisition is expected to be accretive to our earnings in the first full year of operations, which will include the first quarter of 2016.

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

(in thousands)	Purchase Price Allocation
Purchase price	$57,658
Property plant and equipment	53,202
Cash	6,806
Accounts receivable	3,629
Income taxes receivable	3,012
Other assets	247
Total assets acquired	66,896
Long-term debt	1,696
Deferred income taxes	12,987
Accounts payable	3,837
Other current liabilities	314
Total liabilities assumed	18,834
Net identifiable assets acquired	48,062
Goodwill	$9,596

The excess of the purchase price over the estimated fair values of the assets acquired and the liabilities assumed was recognized as goodwill at the acquisition date. 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 expected to be deductible for income tax purposes. We will complete the final purchase price allocation as soon as practicable, but no later than one year from the purchase of the assets.

In December 2015, we adjusted the allocation of the purchase price based on additional information available. The adjustments resulted in a change in the fair value of property, plant and equipment and deferred income tax liabilities. Goodwill from the merger decreased from $11.1 million to $9.6 million after incorporating these adjustments. The valuation of additional contingent cash consideration may be adjusted as additional information becomes available.

Other acquisitions

On May 7, 2015, we purchased certain propane distribution assets from Anderson Gas used to serve 253 customers in Citrus County, Florida for approximately $242,000. In connection with this acquisition, we recorded $186,000 in intangible assets related to a non-compete agreement and the customer list to be amortized over six years and 10 years, respectively. The remaining purchase price was allocated to property, plant and equipment and accounts receivable. The revenue and net income from this acquisition that were included in our consolidated statements of income for the year ended December 31, 2015 were not material.

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 statements of income for the years ended December 31, 2014 and 2013, included $15.1 million and $19.1 million of revenue, respectively, and $232,000 and $155,000 of net loss, respectively, 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. The segments are evaluated based on their pre-tax operating income. Our operations comprise two reportable segments:

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- Regulated Energy. The Regulated Energy segment 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. The Unregulated Energy segment includes propane distribution and wholesale marketing operations, and natural gas marketing operations, which are unregulated as to their rates and services. Effective April 1, 2015, this segment includes Aspire Energy, whose services include natural gas gathering, processing, transportation and supply (See Note 4, Acquisitions and Dispositions, regarding the acquisition of Gatherco). 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.

We had previously identified "Other" as a separate reportable segment, which consisted primarily of our former advanced information services subsidiary. As a result of the sale of that subsidiary on October 1, 2014, "Other" is no longer a separate reportable segment.

The following table presents information about our reportable segments.

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Operating Revenues, Unaffiliated Customers			
Regulated Energy	$300,674	$299,345	$263,573
Unregulated Energy	158,570	184,557	161,760
Other businesses and eliminations	—	14,932	18,973
Total operating revenues, unaffiliated customers	$459,244	$498,834	$444,306
Intersegment Revenues [1]			
Regulated Energy	$1,228	$1,097	$1,064
Unregulated Energy	3,537	404	4,963
Other businesses	880	979	1,017
Total intersegment revenues	$5,645	$2,480	$7,044
Operating Income			
Regulated Energy	$60,985	$50,451	$50,084
Unregulated Energy	16,355	11,723	12,353
Other businesses and eliminations	418	105	297
Operating Income	77,758	62,279	62,734
Gains from sales of businesses	—	7,139	—
Other income, net of other expenses	293	101	372
Interest charges	10,006	9,482	8,234
Income Before Income taxes	68,045	60,037	54,872
Income taxes	26,905	23,945	22,085
Net Income	$41,140	$36,092	$32,787
Depreciation and Amortization			
Regulated Energy	$24,195	$21,915	$19,822
Unregulated Energy	5,679	3,994	3,686
Other businesses and eliminations	98	407	457
Total depreciation and amortization	$29,972	$26,316	$23,965
Capital Expenditures			
Regulated Energy	$98,372	$84,959	$95,944
Unregulated Energy	38,347	9,648	4,829
Other businesses	5,994	3,450	7,266
Total capital expenditures	$142,713	$98,057	$108,039

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

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	As of December 31,	
	2015	2014
Identifiable Assets		
Regulated Energy	$870,559	$796,021
Unregulated Energy	172,803	84,732
Other businesses	25,224	23,716
Total identifiable assets	$1,068,586	$904,469

Our operations are now entirely domestic. Previously, BravePoint 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, 2015, 2014 and 2013 were as follows:

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Cash paid for interest	$9,497	$8,870	$7,837
Cash paid for income taxes, net of refunds	$11,076	$17,588	$4,993

Non-cash investing and financing activities during the years ended December 31, 2015, 2014, and 2013 were as follows:

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Capital property and equipment acquired on account, but not paid as of December 31	$2,668	$459	$341
Common stock issued for the Retirement Savings Plan	$690	$602	—
Common stock issued for the conversion of debentures	$—	$535	$295
Common stock issued under the SICP	$1,594	$1,533	$850
Capital lease obligation	$4,824	$6,130	$7,126
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 their 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 its inventory or cash flow hedges of its future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of December 31, 2015, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2015

In October 2015, PESCO entered into natural gas futures contracts associated with the purchase and sale of natural gas sales to specific customers. These contracts all expire within two years and we accounted for them as cash flow hedges. There is no ineffective portion of these hedges. At December 31, 2015, PESCO had a total of 1,410 Dts/d hedged under natural gas futures contracts, with a fair value of $109,000. The changes in fair value of the contracts are recognized as gains or losses in revenues on the consolidated statements of income in the period of change.

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

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heating season. The put options are exercised if propane prices fall 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. If exercised, we will receive the difference between the market price and the strike price during those months. We accounted for the put options as fair value hedges, and there is no ineffective portion of these hedges. As of December 31, 2015, the put options had a fair value of $152,000. The change in fair value of the put options effectively reduced our propane inventory balance.

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 receives the difference between the index prices (Mont Belvieu prices in December 2015 through March 2016) and the swap prices, which range from $0.5200 to $0.5950 per gallon, for each swap agreement, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap prices, Sharp will pay the difference. These swap agreements essentially fix the price of the 2.5 million gallons that we expect to purchase for the upcoming heating season. We accounted for the swap agreements as cash flow hedges, and there is no ineffective portion of these hedges. At December 31, 2015, the swap agreements had a liability fair value of $323,000. The changes in fair value of the swap agreements are recognized as gains or losses in revenues on the consolidated statements of income in the period of change.

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 pay 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 those months for the swap agreements. At December 31, 2014, 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 the 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.

Hedging Activities in 2013

In June 2013, Sharp entered into put options to protect against the decline in propane prices and related potential inventory losses associated with 1.3 million gallons purchased for the propane price cap program during the heating season. If exercised, we would have received the difference between the market price and the strike price if propane prices had fallen below the strike prices of $0.830 per gallon in December 2013 through February of 2014 and $0.860

per gallon in January through March 2014. We accounted for those options as fair value hedges, and there was no ineffective portion of those hedges. We paid $120,000 to purchase the put options, which expired without exercise as the market prices exceeded the strike prices.

In May 2013, Sharp entered into a call option to protect against an increase in propane prices associated with 630,000 gallons we expected to purchase at market-based prices to supply the demands of our propane price cap program customers. The program capped the retail price at a pre-determined level that we could charge to those customers during the 2013-2014 heating season. The call option was exercised because propane prices rose above the strike price of $0.975 per gallon in January through March of 2014. We accounted for this call option as a derivative instrument on a mark-to-market basis with any change in its fair value being reflected in current period earnings. We paid $72,000 to purchase the call option. In January through March of 2014, we received $209,000, representing the difference between the market price and the strike price during those months.

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Commodity Contracts for Trading Activities

Xeron engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, 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 consolidated statements of income in the period of change. As of December 31, 2015, we did not have outstanding trading contracts. As of December 31, 2014, we had the following outstanding trading contracts, which we accounted for as derivatives:

At December 31, 2014	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	4,200,000	$0.5400 - $0.7900	$0.6714
Purchase	4,201,000	$0.4700 - $1.3176	$0.6416

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expired during the first quarter of 2014.

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, 2015, Xeron had a right to offset $431,000 of accounts payable with these two counterparties. At December 31, 2015, Xeron did not have outstanding accounts receivable with these two counterparties. At December 31, 2014, Xeron had a right to offset $1.6 million and $1.2 million of accounts receivable and accounts payable, respectively, 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, 2015 and 2014, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	December 31, 2015	December 31, 2014
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$1	$407
Derivatives designated as fair value hedges			
Put options	Mark-to-market energy assets	152	622
Derivatives designated as cash flow hedges			
Call options	Mark-to-market energy assets	—	26
Total asset derivatives		$153	$1,055

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	December 31, 2015	December 31, 2014
Derivatives not designated as hedging instruments			
Forward contracts		$1	$283

	Mark-to-market energy liabilities		
Propane swap agreements	Mark-to-market energy liabilities	—	735
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		$433	$1,018

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

(in thousands)	Location of Gain (Loss) on Derivatives	Amount of Gain (Loss) on Derivatives: For the Year Ended December 31, 2015	2014	2013
Derivatives not designated as hedging instruments:				
Realized gain on forward contracts and options [1]	Revenue	$426	$1,423	$1,127
Unrealized gain (loss) on forward contracts [1]	Revenue	(126)	57	217
Call options	Cost of Sales	—	—	97
Propane swap agreements	Cost of Sales	18	(735)	—
Derivatives designated as fair value hedges:				
Put/Call option	Cost of Sales	528	235	(28)
Put/Call option [2]	Propane Inventory	43	517	(100)
Derivatives designated as cash flow hedges				
Propane swap agreements	Cost of Sales	(120)	(341)	—
Propane swap agreements	Other Comprehensive Loss	(323)	—	—
Call options	Cost of Sales	(81)	(17)	—
Call options	Other Comprehensive Loss	—	(55)	—
Natural gas futures contracts	Other Comprehensive Income	109	—	—
Total		$474	$1,084	$1,313

(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 hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). 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).

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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, 2015 and 2014, respectively:

As of December 31, 2015	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$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	$—

As of December 31, 2014	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—guaranteed income fund	$287	$—	$ —	$287
Investments—mutual funds and other	$3,391	$3,391	$ —	$—
Mark-to-market energy assets, including put and call options	$1,055	$—	$ 1,055	$—
Liabilities:				
Mark-to-market energy liabilities including swap agreements	$1,018	$—	$ 1,018	$—

The following valuation techniques were used to measure fair value assets in the tables above on a recurring basis as of December 31, 2015 and 2014:

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.

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.

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The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2015 and 2014:

	For the Year Ended December 31,	
	2015	2014
(in thousands)		
Beginning Balance	$287	$458
Purchases and adjustments	69	76
Transfers/Disbursements	(82)	(253)
Investment income	5	6
Ending Balance	$279	$287

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

At December 31, 2015 and 2014, 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, 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 a fair value of $165.1 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, 2014, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $161.5 million, compared to the estimated fair value of $180.7 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

Note 16, Employee Benefit Plans, provides the fair value measurement information for our pension plan assets.

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9. INVESTMENTS

The investment balances at December 31, 2015 and 2014, consisted of the following:

(in thousands)	December 31, 2015	December 31, 2014
Rabbi trust (associated with the Non-qualified Deferred Compensation Plan)	$3,626	$3,678
Investments in equity securities	18	—
Total	$3,644	$3,678

We classify these investments as trading securities and report them at their fair value. For the years ended December 31, 2015, 2014 and 2013, we recorded net unrealized gains of $7,000, $237,000 and $489,000, respectively, in other income in the consolidated statements of income related to these investments. We have also 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 Rabbi Trusts. During 2013, we sold our investments in equity securities at that time and recorded $702,000 of realized gain, $438,000 of which was previously recorded as unrealized gain ($135,000 in 2012 and $304,000 prior to 2012).

10. GOODWILL AND OTHER INTANGIBLE ASSETS

The carrying value of goodwill as of December 31, 2015 and 2014 was as follows:

	As of December 31,	
(in thousands)	2015	2014
Regulated Energy	$3,353	$3,354
Unregulated Energy	11,195	1,598
Total	$14,548	$4,952

As of December 31, 2015, 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, 2015, goodwill in our Unregulated Energy segment is comprised of $9.6 million from the acquisition of Gatherco in April 2015, $724,000 from the purchase of the operating assets of Glades Gas Co., Inc. in February 2013, $200,000 from the purchase of the operating assets from Crescent Propane, Inc. in December 2011 and $674,000 related to the premium paid by Sharp from its acquisitions in the late 1980s and 1990s.

The annual impairment testing for 2015 indicated no impairment of goodwill. As discussed in Note 2, Summary of Significant Accounting Policies, at December 31, 2014, we recorded an impairment loss of $237,000 associated with the goodwill resulting from the Austin Cox acquisition in 2013. The impairment loss represents all of the goodwill recorded from the Austin Cox acquisition.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2015 and 2014 are as follows:

	As of December 31,			
	2015		2014	
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Customer lists	$4,012	$2,048	$3,993	$1,719
Non-Compete agreements	270	103	103	72
Other	270	179	270	171
Total	$4,552	$2,330	$4,366	$1,962

The customer lists acquired in the purchases of the operating assets of Anderson Gas in May 2015, Glades in February 2013, Virginia LP Gas, Inc. in February 2010 and the FPU merger in October 2009 are being amortized over seven to 12 years. The non-

compete agreements acquired in the purchase of the operating assets of Anderson Gas in May 2015 and Virginia LP Gas, Inc. in February 2010 are being amortized over a six-year and seven-year period, respectively. 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. As discussed in Note 2, Summary of Significant Accounting Policies, at December 31, 2014, we recorded an impairment loss of $175,000 for an intangible asset associated with the non-compete agreements acquired in the Austin Cox acquisition in 2013. The impairment loss represents all of the remaining intangible asset from the Austin Cox acquisition.
For the years ended December 31, 2015, 2014 and 2013, amortization expense of intangible assets was $367,000, $396,000, and $373,000, respectively. Amortization expense of intangible assets is expected to be: $355,000 for 2016, $351,000 for 2017, $353,000 for 2018, $353,000 for 2019 and $353,000 for 2020.

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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.

The IRS performed its examination of Chesapeake Utilities' consolidated federal income tax return for 2009 and FPU's consolidated federal income tax return for 2008 and the period from January 1, 2009 to October 28, 2009 (the pre-merger period in 2009, during which FPU was required to file a separate federal income tax return). Both of the IRS examinations were completed in 2012 without any material findings.

The State of Florida performed its examination of Chesapeake Utilities' state income tax returns for 2008, 2009 and 2010 and completed its examination in 2012 without any material findings.

The State of Texas performed its examination of Chesapeake Utilities' amended state tax return for 2007. We amended the 2007 Texas state tax return due to a change in the methodology used to calculate gross receipts for determining Texas apportionment. This new methodology was used in Chesapeake Utilities' Texas tax returns for all years after 2006. As a result of this change in methodology and the uncertainty of the examination's outcome, we recorded a liability of $300,000 in 2012 associated with unrecognized tax benefits. As of December 31, 2015 and 2014, the balance of the liability was $50,000 and $100,000, respectively, which was based on the findings of the examination. This unrecognized tax benefit liability was recorded in income taxes payable, which reduced income taxes receivable in the accompanying balance sheets at December 31, 2015 and 2014.

We did not have net operating losses for federal income tax purposes as of December 31, 2015 and 2014. We had state net operating losses of $25.7 million in various states as of December 31, 2015, almost all of which will expire in 2034. We have recorded a deferred tax asset of $884,000 and $1.2 million related to net operating loss carry-forwards at December 31, 2015 and 2014, respectively. We have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will be fully utilized.

The following tables provide: (a) the components of income tax expense in 2015, 2014, and 2013; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2015, 2014, and 2013; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2015 and 2014.

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Current Income Tax Expense			
Federal	$4,875	$434	$4,882
State	1,533	1,311	2,382
	(23)	(35)	(39)
Total current income tax expense	6,385	1,710	7,225
Deferred Income Tax Expense [1]			
Property, plant and equipment	21,205	20,382	16,758
Deferred gas costs	(1,539)	1,614	(209)
Pensions and other employee benefits	(84)	537	(335)
FPU merger related premium cost and deferred gain	(556)	(802)	(686)
Net operating loss carryforwards	2,078	(112)	62
Other	(584)	616	(730)
Total deferred income tax expense	20,520	22,235	14,860
Total Income Tax Expense	$26,905	$23,945	$22,085

(1) Includes $2.1 million, $2.6 million, and $2.1 million of deferred state income taxes for the years 2015, 2014 and 2013, respectively.

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	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Reconciliation of Effective Income Tax Rates			
Continuing Operations			
Federal income tax expense [1]	$23,865	$21,121	$19,205
State income taxes, net of federal benefit	3,062	2,946	3,105
ESOP dividend deduction	(263)	(267)	(256)
Other	241	145	31
Total Income Tax Expense	$26,905	$23,945	$22,085
Effective Income Tax Rate	39.54%	39.88%	40.25%

[1] Federal income taxes were recorded at 35% for each year represented.

	As of December 31,	
	2015	2014
(in thousands)		
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	$185,448	$152,877
Acquisition adjustment	15,490	16,140
Loss on reacquired debt	485	529
Deferred gas costs	683	2,222
Other	5,961	4,507
Total deferred income tax liabilities	208,067	176,275
Deferred income tax assets:		
Pension and other employee benefits	6,570	6,532
Environmental costs	2,445	2,313
Net operating loss carryforwards	943	1,186
Self insurance	278	275
Storm reserve liability	1,153	1,150
Other	4,078	3,755
Total deferred income tax assets	15,467	15,211
Deferred Income Taxes Per Consolidated Balance Sheets	$192,600	$161,064

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12. LONG-TERM DEBT

Our outstanding long-term debt is shown below:

	As of December 31,	
(in thousands)	2015	2014
FPU secured first mortgage bonds:		
9.08% bond, due June 1, 2022	$7,973	$7,969
Uncollateralized Senior Notes:		
6.64% note, due October 31, 2017	5,456	8,182
5.50% note, due October 12, 2020	10,000	12,000
5.93% note, due October 31, 2023	24,000	27,000
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	238	314
Capital lease obligation	4,824	6,130
Total long-term debt	158,491	167,595
Less: current maturities	(9,151)	(9,109)
Total long-term debt, net of current maturities	$149,340	$158,486

Annual maturities and principal repayments of consolidated long-term debt, excluding the capital lease obligation, are as follows: $9,151 for 2016; $12,099 for 2017; $9,421 for 2018; $11,245 for 2019; $15,600 for 2020 and $101,000 thereafter. See Note 14, Lease obligations for future payments related to the capital lease obligation.

Shelf Agreement

On October 8, 2015, we entered into a Shelf Agreement with Prudential. Under the terms of the Shelf Agreement, we may request that Prudential purchase, over the next three years, 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.

Secured First Mortgage Bonds

We guaranteed FPU’s secured 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, 2015, FPU’s cumulative net income base was $116.3 million, offset by restricted payments of $37.6 million, leaving $78.7 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 $47.1 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2015. This represents approximately 13 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.

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Uncollateralized Senior Notes

In September 2013, we entered into the Note Agreement to issue $70.0 million in aggregate Senior Notes to the Note Holders. In December 2013, we issued Series A Notes, with an aggregate principal amount of $20.0 million, at an interest rate of 3.73 percent. On May 15, 2014, we issued Series B Notes, with an aggregate principal amount of $50.0 million, at an interest rate of 3.88 percent. The proceeds received from the issuances of the Series A and Series B Notes were used to reduce our short-term borrowings under our lines of credit and to fund capital expenditures.

In June 2010, we entered into an agreement with Metropolitan Life Insurance Company and New England Life Insurance Company to issue up to $36.0 million of Chesapeake Utilities' Senior Notes. In June 2011, we issued $29.0 million of 5.68 percent Senior Notes to permanently finance the redemption of two series of FPU first mortgage bonds in 2010. On May 2, 2013, we issued an additional $7.0 million of 6.43 percent Senior Notes under the same agreement.

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. As of December 31, 2015, we are in compliance with all of our debt covenants.

Most of 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, 2015, the cumulative consolidated net income base was $285.0 million, offset by restricted payments of $138.4 million, leaving $146.6 million of cumulative net income free of restrictions.

13. SHORT-TERM BORROWINGS

At December 31, 2015 and 2014, we had $173.4 million and $88.2 million, respectively, of short-term borrowings outstanding. On October 8, 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. On October 31, 2015, two credit facilities available under uncommitted lines of credit, totaling $40.0 million expired and were not renewed. As a result, we now have 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 1.30 percent and 1.15 percent for 2015 and 2014, respectively. We incurred commitment fees of $106,000 and $87,000 in 2015 and 2014, respectively.

(in thousands)	Total Facility	Interest Rate	Expiration Date	Outstanding borrowings at December 31, 2015	Outstanding borrowings at December 31, 2014	Available at December 31, 2015
Bank Credit Facility						
Committed revolving credit facility A	$55,000	LIBOR plus 1.25 percent	October 31, 2016	$30,000	$20,000	$25,000
Committed revolving credit facility B	30,000	LIBOR plus 1.25 percent (1)	October 31, 2016	23,757	16,040	6,243
Committed revolving credit facility C	35,000	LIBOR plus 0.85 percent	December 20, 2016	30,000	—	5,000
Committed revolving credit facility D	150,000	LIBOR plus 1.25 percent (2)	October 8, 2020	35,000	—	115,000
	50,000		October 31, 2016	50,000	50,000	—

Short-term revolving credit Note E		LIBOR plus 0.80 percent [3]			
Total short term credit facilities	$320,000		$168,757	$86,040	$151,243
Book overdrafts[4]			4,640	2,191	
Total short-term borrowing			$173,397	$88,231	

[1] This facility bears interest at LIBOR for the applicable period plus up to 1.25 percent, if requested three days prior to the advance date. If requested and
advanced on the same day, this facility bears interest at a base rate plus up to 1.25 percent.

[2] This facility bears interest at LIBOR for the applicable period plus 1.25 percent or less, based on Total Indebtedness as a percentage of Total Capitalization.

[3] At our discretion, the borrowings under this facility can bear interest at the lender's base rate plus 0.80 percent.

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(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 were previously authorized by our Board of Directors to borrow up to $200.0 million of short-term debt, as required, from these short-term lines of credit. In February 2016, the Board of Directors, authorized an increase which allows us to borrow up to $275.0 million of short-term debt.
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; and
- a fixed charge coverage ratio of at least 1.20 to 1.0.

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 2015, 2014 and 2013 was $1.7 million, $1.8 million and $1.6 million, respectively. Future minimum payments under our current lease agreements for the years 2016 through 2020 are $1.3 million, $649,000, $484,000, $424,000, and $273,000, respectively, and approximately $2.2 million thereafter, with an aggregate total of approximately $5.3 million.
For the years ended December 31, 2015 and 2014, we paid $1.5 million and $1.1 million, respectively, for a capital lease arrangement related to Sandpiper's capacity, supply and operating agreement. Future minimum payments under this lease arrangement are $1.5 million for 2016 through 2018 and $625,000 in 2019, with an aggregate total of $5.1 million.

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15. ACCUMULATED OTHER COMPREHENSIVE INCOME (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, 2015 and 2014. All amounts in the following table are presented net of tax.

(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 gain/(loss)	63	(227)	(164)
As of December 31, 2015	$(5,580)	$(260)	$(5,840)

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2013	$(2,533)	$—	$(2,533)
Other comprehensive loss before reclassifications	(3,242)	(482)	(3,724)
Amounts reclassified from accumulated other comprehensive loss	132	449	581
Net current-period other comprehensive loss	(3,110)	(33)	(3,143)
As of December 31, 2014	$(5,643)	$(33)	$(5,676)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the years ended December 31, 2015 and 2014. Deferred gains and losses of our commodity contracts cash flow hedges are recognized in earnings upon settlement.

For the Year Ended December 31,	2015	2014
(in thousands)		
Amortization of defined benefit pension and postretirement plan items:		
Prior service cost [(1)]	$68	$58
Net gain [(1)]	(650)	(279)
Total before income taxes	(582)	(221)
Income tax benefit	233	89
Net of tax	$(349)	$(132)
Gains and losses on commodity contracts cash flow hedges		
Propane swap agreements [(2)]	$(120)	$(735)
Call options [(2)]	(55)	(17)
Natural gas futures [(2)]	(31)	—
Total before income taxes	(206)	(752)
Income tax benefit	83	303
Net of tax	$(123)	$(449)

Total reclassifications for the period	$(472)	$(581)

(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.

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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 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 merger, the FPU Pension Plan was frozen with respect to additional years of service and additional compensation, effective December 31, 2009.

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 date the Plan was frozen were credited with two additional years of service.

In January 2011, a former executive officer retired and received a lump-sum pension distribution from the Chesapeake Pension Plan. Based upon the funding status of the Chesapeake Pension Plan at the time, which did not meet or exceed 110 percent of the benefit obligation as required per the Department of Labor regulations, our former executive officer was required to deposit property equal to 125 percent of the restricted portion of his lump-sum distribution into an escrow. Each year, an amount equal to the value of payments that would have been paid to him if he had elected the life annuity form of distribution becomes unrestricted. Property equal to the life annuity amount is returned to him from the escrow account. These same regulations will apply to the top 20 highest compensated employees taking lump-sum distributions from the Chesapeake Pension Plan.

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The following schedule sets forth the funded status at December 31, 2015 and 2014 and the net periodic cost for the years ended December 31, 2015, 2014 and 2013 for the Chesapeake and FPU Pension Plans:

At December 31,	Chesapeake Pension Plan 2015	2014	FPU Pension Plan 2015	2014
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	$11,981	$10,268	$68,173	$55,876
Interest cost	407	425	2,504	2,613
Actuarial loss (gain)	(401)	1,891	(3,374)	12,785
Benefits paid	(486)	(603)	(2,868)	(3,101)
Benefit obligation — end of year	11,501	11,981	64,435	68,173
Change in plan assets:				
Fair value of plan assets — beginning of year	9,078	8,743	45,077	44,337
Actual return on plan assets	(289)	305	(1,464)	1,485
Employer contributions	449	633	1,462	2,356
Benefits paid	(486)	(603)	(2,868)	(3,101)
Fair value of plan assets — end of year	8,752	9,078	42,207	45,077
Reconciliation:				
Funded status	(2,749)	(2,903)	(22,228)	(23,096)
Accrued pension cost	$(2,749)	$(2,903)	$(22,228)	$(23,096)
Assumptions:				
Discount rate	3.75%	3.50%	4.00%	3.75%
Expected return on plan assets	6.00%	6.00%	7.00%	7.00%

For the Years Ended December 31,	Chesapeake Pension Plan 2015	2014	2013	FPU Pension Plan 2015	2014	2013
(in thousands)						
Components of net periodic pension cost:						
Interest cost	$407	$425	$405	$2,504	$2,613	$2,367
Expected return on assets	(530)	(516)	(486)	(3,107)	(3,089)	(2,866)
Amortization of prior service cost	—	—	(1)	—	—	—
Amortization of actuarial loss	392	176	322	456	8	330
Net periodic pension cost	269	85	240	(147)	(468)	(169)
Amortization of pre-merger regulatory asset	—	—	—	761	761	761
Total periodic cost	$269	$85	$240	$614	$293	$592
Assumptions:						
Discount rate	3.50%	4.25%	3.50%	3.75%	4.75%	3.75%
Expected return on plan assets	6.00%	6.00%	6.00%	7.00%	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 was 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 $2.8 million and $3.6

million at December 31, 2015 and 2014, respectively.

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The following sets forth the funded status at December 31, 2015 and 2014 and the net periodic cost for the years ended December 31, 2015, 2014 and 2013 for the Chesapeake SERP:

At December 31,	2015	2014
(in thousands)		
Change in benefit obligation:		
Benefit obligation — beginning of year	$2,650	$2,210
Interest cost	91	92
Actuarial loss (gain)	(85)	437
Benefits paid	(146)	(89)
Benefit obligation — end of year	2,510	2,650
Change in plan assets:		
Fair value of plan assets — beginning of year	—	—
Employer contributions	146	89
Benefits paid	(146)	(89)
Fair value of plan assets — end of year	—	—
Reconciliation:		
Funded status	(2,510)	(2,650)
Accrued pension cost	$(2,510)	$(2,650)
Assumptions:		
Discount rate	3.75%	3.50%

For the Years Ended December 31,	2015	2014	2013
(in thousands)			
Components of net periodic pension cost:			
Interest cost	$91	$92	$81
Amortization of prior service cost	9	19	19
Amortization of actuarial loss	99	47	64
Net periodic pension cost	$199	$158	$164
Assumptions:			
Discount rate	3.50%	4.25%	3.50%

Our funding policy provides that payments to the trustee of each qualified plan shall be equal to at least the minimum funding requirements of the Employee Retirement Income Security Act of 1974. The following schedule summarizes the assets of the Chesapeake Pension Plan and the FPU Pension Plan, by investment type, at December 31, 2015, 2014 and 2013:

	Chesapeake Pension Plan			FPU Pension Plan		
At December 31,	2015	2014	2013	2015	2014	2013
Asset Category						
Equity securities	48.01%	51.42%	54.40%	48.56%	52.62%	55.02%
Debt securities	39.62%	37.31%	36.54%	41.74%	37.69%	36.54%
Other	12.37%	11.27%	9.06%	9.70%	9.69%	8.44%
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.

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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, 2015, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

	Fair Value Measurement Hierarchy			
Asset Category	Level 1	Level 2	Level 3	Total
(in thousands)				
Equity securities				
U.S. Large Cap [1]	$3,641	$4,030	$—	$7,671
U.S. Mid Cap [1]	1,577	1,609	—	3,186
U.S. Small Cap [1]	865	818	—	1,683
International [2]	9,416	—	—	9,416
Alternative Strategies [3]	2,737	—	—	2,737
	18,236	6,457	—	24,693
Debt securities				
Fixed income [4]	18,565	—	—	18,565
High Yield [4]	2,521	—	—	2,521
	21,086	—	—	21,086
Other				
Commodities [5]	1,365	—	—	1,365
Real Estate [6]	2,529	—	—	2,529
Guaranteed deposit [7]	—	—	1,286	1,286
	3,894	—	1,286	5,180
Total Pension Plan Assets	$43,216	$6,457	$1,286	$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.

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At December 31, 2014, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

	Fair Value Measurement Hierarchy			
Asset Category	Level 1	Level 2	Level 3	Total
(in thousands)				
Equity securities				
U.S. Large Cap [1]	$4,069	$4,028	$—	$8,097
U.S. Mid Cap [1]	1,733	1,714	—	3,447
U.S. Small Cap [1]	873	821	—	1,694
International [2]	9,621	—	—	9,621
Alternative Strategies [3]	5,531	—	—	5,531
	21,827	6,563	—	28,390
Debt securities				
Fixed income [4]	17,717	—	—	17,717
High Yield [4]	2,658	—	—	2,658
	20,375	—	—	20,375
Other				
Commodities [5]	1,819	—	—	1,819
Real Estate [6]	2,427	—	—	2,427
Guaranteed deposit [7]	—	—	1,144	1,144
	4,246	—	1,144	5,390
Total Pension Plan Assets	$46,448	$6,563	$1,144	$54,155

(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.

At December 31, 2015 and 2014, all of the investments classified under Level 1 of the fair value measurement hierarchy were recorded at fair value based on unadjusted quoted prices in active markets for identical investments. The Level 2 investments were recorded at fair value based on net asset value per unit of the investments, which used significant observable inputs although those investments were not traded publicly and did not have quoted market prices in active markets. 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, 2015 and 2014:

	For the Year Ended December 31,	
	2015	2014
(in thousands)		
Balance, beginning of year	$1,144	$602
Purchases	1,926	1,811
Transfers in	1,900	2,390

Disbursements	(3,688)	(3,704)
Investment income	4	45
Balance, end of year	$1,286	$1,144

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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, 2015 and 2014 and the net periodic cost for the years ended December 31, 2015, 2014, and 2013:

	Chesapeake Postretirement Plan		FPU Medical Plan	
At December 31,	2015	2014	2015	2014
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	$1,238	$1,262	$1,712	$1,519
Interest cost	42	39	57	69
Plan participants contributions	108	106	75	97
Actuarial loss (gain)	(58)	6	(132)	375
Benefits paid	(177)	(175)	(268)	(348)
Benefit obligation — end of year	1,153	1,238	1,444	1,712
Change in plan assets:				
Fair value of plan assets — beginning of year	—	—	—	—
Employer contributions[1]	69	69	193	251
Plan participants contributions	108	106	75	97
Benefits paid	(177)	(175)	(268)	(348)
Fair value of plan assets — end of year	—	—	—	—
Reconciliation:				
Funded status	(1,153)	(1,238)	(1,444)	(1,712)
Accrued postretirement cost	$(1,153)	$(1,238)	$(1,444)	$(1,712)
Assumptions:				
Discount rate	3.75%	3.50%	4.00%	3.75%

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

Net periodic postretirement benefit costs for 2015, 2014, and 2013 include the following components:

	Chesapeake Postretirement Plan			FPU Medical Plan		
For the Years Ended December 31,	2015	2014	2013	2015	2014	2013
(in thousands)						
Components of net periodic postretirement cost:						
Interest cost	$42	$39	$47	$57	$69	$63
Amortization of:						
Actuarial loss	72	55	74	—	—	—
Prior service cost	(77)	(77)	(77)	—	—	—
Net periodic cost	37	17	44	57	69	63
Amortization of pre-merger regulatory asset	—	—	—	8	8	8
Net periodic cost	$37	$17	$44	$65	$77	$71
Assumptions						
Discount rate	3.50%	4.25%	3.50%	3.75%	4.75%	3.75%

Similar to the FPU Pension Plan, continued amortization of the FPU postretirement benefit 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 $38,000 and $46,000 at December 31, 2015 and 2014, respectively.
The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive income/loss or as a regulatory asset as of December 31, 2015:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$—	$—	$—	$ (755)	$—	$(755)
Net loss	4,434	20,410	866	793	99	26,602
Total	$4,434	$20,410	$866	$ 38	$99	$25,847
Accumulated other comprehensive loss pre-tax[(1)]	$4,434	$3,878	$866	$ 38	$19	$9,235
Post-merger regulatory asset	—	16,532	—	—	80	16,612
Subtotal	4,434	20,410	866	38	99	25,847
Pre-merger regulatory asset	—	2,826	—	—	38	2,864
Total unrecognized cost	$4,434	$23,236	$866	$ 38	$137	$28,711

(1) The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2015 is net of income tax benefits of $3.7 million.

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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 income/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 benefit cost in 2016 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	$412	$512	$87	$ 67	$—	$1,078
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 2015, 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. We adopted a new mortality table (RP 2014), which was developed by the Society of Actuaries and published during 2014. In December of 2015, we adopted an updated mortality table (RP 2014 with Scale MP-2015).

The health care inflation rate for 2015 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 $335,000 as of December 31, 2015, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2015 by approximately $13,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $268,000 as of December 31, 2015, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2015 by approximately $10,000.

Estimated Future Benefit Payments

In 2016, we expect to contribute $505,000 and $1.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $151,000 to the Chesapeake SERP. We also expect to contribute $82,000 and $149,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2016. The schedule below shows the estimated future benefit payments for each of the plans previously described:

	Chesapeake Pension Plan(1)	FPU Pension Plan(1)	Chesapeake SERP(2)	Chesapeake Postretirement Plan(2)	FPU Medical Plan(2)
(in thousands)					
2016	$591	$2,980	$151	$82	$149
2017	$717	$3,000	$150	$80	$130
2018	$640	$3,047	$150	$79	$93
2019	$686	$3,129	$148	$79	$100

2020	$646	$3,218	$147	$73	$94
Years 2021 through 2025	$4,706	$17,469	$960	$322	$424

(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.

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Retirement Savings Plan

For the years ended December 31, 2015, 2014 and 2013, we sponsored a Retirement Savings Plan. Prior to January 1, 2014, we also sponsored a 401(k) SERP non-qualified supplemental executive retirement savings plan. That plan was merged with the Deferred Compensation Plan on January 1, 2014 to form the Non-Qualified Deferred Compensation Plan, which is described in the following section.

Our 401(k) plan is offered to all eligible employees who have completed three 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. Effective January 1, 2011, 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. 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. Beginning January 1, 2011, the employer matching contribution is made in cash and is invested based on a participant's investment directions. 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.

Contributions to all of our retirement savings plans totaled $4.1 million, $4.1 million and $3.7 million for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015, there are 843,037 shares of our common stock reserved to fund future contributions to the Retirement Savings Plan.

Non-Qualified Deferred Compensation Plan

Effective January 1, 2014, our 401(k) SERP was amended, restated and renamed as the Chesapeake Utilities Corporation Non-Qualified Deferred Compensation Plan. In addition, the Deferred Compensation Plan was consolidated into this plan. As a result of these actions, the 401(k) SERP and the Deferred Compensation Plan are now administered as a single 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. 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 qualified 401(k) 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 two 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 qualified 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 assumed to be reinvested into our common stock. Assets held in the Rabbi Trust had a fair value of $3.6 million and $3.7 million at December 31, 2015 and 2014, 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 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 sheet and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Deferred Compensation Plan totaled $1.9 million and $1.3 million at December 31, 2015 and 2014, respectively.

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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 575,473 shares 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, 2015, 2014 and 2013:

	For the Year Ended December 31,		
	2015	2014	2013
(in thousands)			
Awards to non-employee directors	$640	$540	$478
Awards to key employees	1,297	1,418	1,153
Total compensation expense	1,937	1,958	1,631
Less: tax benefit	(780)	(790)	(657)
Share-Based Compensation amounts included in net income	$1,157	$1,168	$974

Stock Options

We did not have any stock options outstanding at December 31, 2015, or 2014, nor were any stock options issued during 2015, 2014 and 2013.

Non-employee Directors

Shares granted to non-employee directors are issued in advance of the 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 2015, each of our non-employee directors received an annual retainer of 1,207 shares of common stock under the SICP for board service through the 2016 Annual Meeting of Stockholders. A summary of stock activity for our non-employee directors for the years ended December 31, 2015, 2014 and 2013 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding — December 31, 2013	—	$ —
Granted [1]	13,827	$ 41.60
Vested [1]	(13,827)	$ 41.60
Outstanding — December 31, 2014	—	$ —
Granted	14,484	$ 45.54
Vested	(14,484)	$ 45.54
Outstanding — December 31, 2015	—	$ —

[1] In November 2014, we added a new member to our Board of Directors. The number of shares granted to the director for his annual retainer was prorated.

The weighted average grant date fair value of shares granted to our non-employee directors during 2015, 2014 and 2013 was $45.54, $41.60 and $34.99 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, 2015, there was $220,000 of unrecognized compensation expense related to these awards. This expense will be fully recognized by April 2016, 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 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.

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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, 2013	121,142	$28.20
Granted	41,442	$39.99
Vested	(39,546)	$26.87
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

In 2015, 2014 and 2013, we withheld shares with 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 12,620, 12,687 and 15,617 for 2015, 2014 and 2013, 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 $592,000, $503,000 and $519,000, in 2015, 2014 and 2013, respectively. The tax benefits associated with these obligations for 2015, 2014 and 2013 are $297,000, $398,000, and $202,000, respectively, and is included in additional paid-in capital in the consolidated statements of stockholders' equity.
The weighted average grant-date fair value of shares awards granted to key employees during 2015, 2014 and 2013 was $47.65, $39.99 and $29.90 per share, respectively. The intrinsic value of these awards was $6.3 million, $6.1 million and $4.8 million for 2015, 2014 and 2013, respectively. At December 31, 2015, there was $1.4 million of unrecognized compensation cost related to these awards, which is expected to be recognized during 2016 and 2017.

18. RATES AND OTHER REGULATORY ACTIVIT IES

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: On December 21, 2015, our Delaware division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. Delaware division proposed a base rate increase of $4.7 million or nearly 10 percent of existing revenues based on the test period ending March 31, 2016. Included in the application are new service offerings to promote growth and a revenue decoupling mechanism for residential and small commercial customers. A decision on the application is expected during the third quarter of 2016. Pending the decision, the Delaware division proposed to increase rates on an interim basis by $2.5 million beginning February 19, 2016. These rates, which are subject to refund, represent a five percent increase over current rates.

Maryland

Ocean City SIR Filing: On July 2, 2015, Sandpiper filed an application with the Maryland PSC, to establish an SIR to further fund system expansion within the city limits of Ocean City, Maryland. The proposed SIR, which would only be charged to customers located within city limits, was supported by Ocean City's local government. On August 5, 2015, the Maryland PSC approved the application.
Sandpiper Rate Case Filing: On December 1, 2015, Sandpiper filed an application with the Maryland PSC for a base rate increase and certain other changes to its tariff. Sandpiper proposed a base rate increase of $950,000, which represents five percent over existing revenues based on the test period ended December 31, 2015. A decision on the

application is expected during the second

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quarter of 2016. Included in this application is a stratification of rate classes to further match the cost of service, and a revenue decoupling mechanism for residential and small commercial customers.

Florida

On January 16, 2015, Chesapeake Utilities' Florida natural gas distribution division filed a petition with the Florida PSC for approval of a contract with its affiliate, Peninsula Pipeline, for additional natural gas transportation services in the vicinity of Haines City, located in Polk County, Florida. This petition was approved by the Florida PSC at its Agenda Conference on May 5, 2015.

On July 1, 2015, FPU's electric division filed an electric depreciation study with the Florida PSC, which approved new depreciation rates at its Agenda Conference on December 3, 2015. New rates became effective retroactive to January 1, 2015 and resulted in a reduction of approximately $229,000 in annual depreciation expense.

On September 1, 2015, FPU’s electric division filed to recover the cost of the proposed Florida Power & Light Company interconnect project through the annual Fuel and Purchased Power Cost Recovery Clause filing. The 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 on December 3, 2015. On January 22, 2016, the Office of Public Counsel filed an appeal with the Florida Supreme Court opposing the decision on this action.

On September 1, 2015, FPU's Fort Meade division filed a petition with the Florida PSC for approval to implement GRIP. On October 27, 2015, the petition was amended to allow Fort Meade to commence the replacement of steel tubing services in January 2016, although the collection of GRIP surcharges from customers will be delayed until January 2017, pursuant to the terms and conditions of the purchase agreement with the City of Fort Meade. This action was approved by the Florida PSC at its Agenda Conference on December 3, 2015.

Eastern Shore

White Oak Mainline Expansion Project: On November 21, 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 proposes 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. The estimated cost of the project is between $32.0 million and $35.0 million. On January 22, 2015, the FERC issued a Notice of Intent to Prepare an Environmental Assessment for this project. In February, April and May 2015, Eastern Shore filed environmental data in response to comments regarding evaluation of alternate routes for a segment of the pipeline route in the vicinity of the Kemblesville Historic District. On June 2, 2015, a field meeting was conducted to review the proposed route and alternate routes. In response to comments received from the National Park Service and other stakeholders, the FERC requested that Eastern Shore conduct an additional investigation in relation to Eastern Shore's existing right-of-way. On July 9, 2015, the FERC issued a 30-day public scoping notice in advance of issuing an Environmental Assessment in order to solicit comments from the public regarding construction of the Kemblesville loop. On August 18, 2015, Eastern Shore submitted supplemental information to the FERC regarding the results of its investigation of the Kemblesville loop.

On November 18, 2015, Eastern Shore filed an amendment to this application, which indicated the preferred pipeline route. Eastern Shore has responded to the FERC Staff's environmental data requests. On February 10, 2016 the FERC issued a notice to prepare an environmental assessment and will combine both the White Oak Mainline Expansion project and System Reliability Project into a single assessment. The environmental assessment is scheduled to be issued on April 12, 2016, with the FERC's 90-day authorization decision to be issued on July 11, 2016.

System Reliability Project: On May 22, 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 proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore's customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days in 2014 and 2015. The estimated cost of the project is $32.1 million. 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.

On June 8, 2015, the FERC filed a notice of the application, and the comment period ended on June 29, 2015. Two interested parties filed comments and protests with the FERC. Eastern Shore has filed answers with the FERC in response to the comments and protests from the two parties.

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On September 4, 2015, the FERC issued a notice of intent to prepare an environmental assessment and Eastern Shore has responded to the FERC Staff's environmental data requests. On February 10, 2016 the FERC issued a notice to prepare an environmental assessment and will combine both the System Reliability Project and White Oak Mainline Expansion project into a single assessment. The environmental assessment is scheduled to be issued on April 12, 2016, with the FERC's 90-day authorization decision to be issued on July 11, 2016.

TETLP Capacity Expansion Project: On October 13, 2015, Eastern Shore submitted an application to the FERC to make certain measurement and related improvements at its TETLP interconnect facilities, which will enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. On December 22, 2015, the FERC authorized Eastern Shore to proceed with the project.

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, 2015, we had accrued approximately $10.0 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 $10.1 million of which has been recovered as of December 31, 2015, leaving approximately $3.9 million in regulatory assets for future recovery of environmental costs from FPU’s customers.

In addition to the FPU MGP sites, we had recorded $375,000 in environmental liabilities at December 31, 2015, related to Chesapeake Utilities' MGP sites in Salisbury, Maryland and Winter Haven, Florida, representing our estimate of future costs associated with these sites. As of December 31, 2015, we had recorded approximately $87,000 in regulatory and other assets for future recovery through Chesapeake Utilities’ rates.

During the first quarter of 2015, we established $273,000 in environmental liabilities related to Chesapeake Utilities' MGP site in Seaford, Delaware, representing our estimate of future costs associated with this site, and recorded a regulatory asset for the same amount for probable future recovery through Chesapeake Utilities' rates via our environmental rider. On October 29, 2015, we filed an application with the Delaware PSC for recovery of its incurred environmental expenses associated with the Seaford site between October 1, 2014 and September 30, 2015. A final decision is anticipated by the end of the first quarter of 2016. As of December 31, 2015, we had accrued approximately $223,000 in environmental liabilities and $273,000 in regulatory and other assets related to this site.

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. The Start-Up and Monitoring Report, dated November 30, 2015, was submitted for review and comment. It is anticipated that comments will be received from FDEP and that a facility inspection will be conducted with FDEP during the first quarter of 2016.

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

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redevelopment of the properties. We continue to expect that all costs related to these activities will be recoverable from customers through rates.

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, 2015, 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 by FPU in the Third Participation Agreement.

As of December 31, 2015, 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, 2015.

Key West, Florida

FPU formerly owned and operated a MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. In 2010, after 17 years of regulatory inactivity, FDEP observed that some soil and groundwater standards were exceeded and requested implementation of additional soil and groundwater fieldwork. The scope of work is limited to the installation of two additional monitoring wells and periodic monitoring of the new and existing wells. The two additional monitoring wells were installed in November 2011, and groundwater monitoring began in December 2011. The first semi-annual report from the monitoring program was issued in May 2012. The data from the June 2012 and September 2012 monitoring events were submitted to the FDEP on October 4, 2012. FDEP responded on October 9, 2012 that, based on the data, NAM appears to be an appropriate remedy for the site.

In October 2012, FDEP issued a RAP approval order, which requires a limited semi-annual monitoring program. The most recent groundwater-monitoring event was conducted on September 15, 2015. Natural Attenuation Default criteria were met at all locations sampled. The next semi-annual sampling event is scheduled for March of 2016. Although the duration of the FDEP-required limited NAM cannot be determined with certainty, we anticipate that total costs to complete the remedial action will not exceed $50,000. The annual cost to conduct the limited NAM program is not expected to exceed $8,000.

Pensacola, Florida

FPU formerly owned and operated a MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the FDOT. In October 2009, FDEP informed Gulf Power that it would approve a conditional No Further Action determination for the site with the requirement for institutional and engineering controls. On June 16, 2014, FDEP issued a draft memorandum of understanding between FDOT and FDEP to implement site closure with approved institutional and engineering controls for the site. We anticipate that FPU's share of remaining legal and cleanup costs will not exceed $5,000.

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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 indicate 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 to FDEP, dated October 17, 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 on January 8, 2015. FDEP approved the plan to expand the bio-sparging operations in the southern portion of the site, and that work is anticipated to occur during the first quarter of 2016.

Although specific remedial actions for the site have not yet been identified, we estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $443,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site. We continue to believe that the entire amount will be recoverable from customers through rates.

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.

Salisbury, Maryland

We have substantially completed remediation of a site in Salisbury, Maryland, where it was determined that a former MGP caused localized groundwater contamination. In February 2002, the MDE granted permission to permanently decommission the systems used for remediation and to discontinue all on-site and off-site well monitoring, except for one well, which is being maintained for periodic product monitoring and recovery. We anticipate that the remaining costs of the one remaining monitoring well will not exceed $5,000 annually. We cannot predict at this time when the MDE will grant permission to permanently decommission the one remaining monitoring well.

Seaford, Delaware

In a letter dated December 5, 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 require further investigation. In September 17, 2015, the DNREC approved our application to enter this site into the voluntary cleanup program. A remedial investigation was conducted in December 2015, and we anticipate that the remedial investigation report will be submitted to DNREC in the first quarter of 2016. 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. The costs incurred to date associated with remediation activities for these facilities, is approximately $1.0 million. Pursuant to the merger agreement, an escrow was established to fund certain claims by Chesapeake Utilities and Aspire Energy for indemnification by Gatherco, including environmental claims. Gatherco's indemnification obligations for environmental matters apply to remediation costs in excess of $431,250 and are capped at $1.65 million. We expect to be reimbursed for substantially all remediation costs we have incurred to date associated with these pipeline facilities in excess of $431,250.

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20. OTHER COMMITMENTS AND CONTINGENCIES

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations 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 had a contract with an unaffiliated energy marketing and risk management company to manage a portion of their natural gas transportation and storage capacity, which expired on March 31, 2013. On April 1, 2013, we entered into a new contract with a different company to perform similar asset management functions. The new contract expires on March 31, 2017.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with EGWIC to purchase propane over a six -year term. Approximately three years remain under this contract. Sandpiper's current annual commitment is estimated at approximately 6.5 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. Sharp's current annual commitment is estimated at approximately 6.5 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.

In May 2015, PESCO renewed contracts to purchase natural gas from various suppliers for a one-year term. The total monthly purchase commitment ranges from 9,982 to 13,423 Dts/d for a one year term.

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, 2015, FPU was in compliance with all of the requirements of its fuel supply contracts.

The total purchase obligations for natural gas, electric and propane supplies are approximately $72.3 million for 2016, $96.8 million for 2017-2018, $64.4 million for 2019-2020 and $100.8 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 obligations, including the obligations of our subsidiaries. Prior to February 24, 2016, the maximum authorized liability under such guarantees and letters of credit was $50.0 million. On February 24, 2016, the maximum authorized liability was increased by the Board of Directors to $65.0 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, 2015 was $45.6 million, with the guarantees expiring on various dates through December 2016.

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).

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We issued letters of credit totaling $5.6 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 31, 2016. There have been no draws on these letters of credit as of December 31, 2015. 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 $50,000 related to unrecognized income tax benefits and $310,000 related to contingencies for taxes other than income. As of December 31, 2014, we maintained a liability of $100,000 related to unrecognized income tax benefits and $724,000 related to contingencies for taxes other than income.

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			
	March 31	June 30	September 30	December 31
(in thousands except per share amounts)				
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
2014 [1]				
Operating Revenues	$186,337	$100,497	$91,619	$120,380
Operating Income	$31,623	$10,457	$7,792	$12,408
Net Income	$17,681	$5,134	$3,180	$10,097
Earnings per share:				
Basic	$1.22	$0.35	$0.22	$0.69
Diluted	$1.21	$0.35	$0.22	$0.69

(1) The sum of the four quarters does not equal the total year due to rounding.

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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, 2015. 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, 2015.
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, 2015, 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, 2015. In addition, on May 20, 2015, 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.

On April 1, 2015, the previously announced merger between Chesapeake Utilities and Aspire Energy was consummated. Chesapeake Utilities is in the process of integrating Aspire Energy's operations and has not included Aspire Energy's activity in its evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. See “Notes to the Consolidated Financial Statements — Note 4, Acquisitions and Dispositions, for additional information relating to the Aspire Energy merger. Aspire Energy's operations constituted approximately six percent of total assets (excluding goodwill and other intangible assets) as of December 31, 2015, and approximately four percent of operating revenues for the year then ended. Aspire Energy's operations will be included in Chesapeake Utilities' assessment as of December 31, 2016.

Our management has evaluated and concluded that our internal control over financial reporting was effective as of December 31, 2015.

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.

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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, 2015, 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.

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, the Company completed a merger with Gatherco, Inc. ("Gatherco"), in which Gatherco merged with and into Aspire Energy of Ohio, LLC ("Aspire Energy") in 2015. As permitted by the Securities and Exchange Commission, management excluded the non-integrated Aspire Energy operations from its assessment of internal control over financial reporting as of December 31, 2015. Non-integrated Aspire Energy operations constituted approximately 6 percent of total assets (excluding goodwill and other intangible assets) as of December 31, 2015, and 4 percent of operating revenue for the year then ended. Our audit of internal control over financial reporting of the Company as of December 31, 2015, did not include an evaluation of the internal controls over financial reporting of the non-integrated operations of Aspire Energy.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, 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 26, 2016 expressed an unqualified opinion.

/s/ Baker Tilly Virchow Krause, LLP

Philadelphia, Pennsylvania
February 26, 2016

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ITEM 9B. OTHER INFORMATION.
None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANACE.
The information required by this Item is incorporated herein by reference to the portions of the 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,” to be filed no later than March 31, 2016, in connection with our Annual Meeting to be held on or about May 6, 2016.
The information required by this Item with respect to executive officers is, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, set forth in this report following Item 3, as Item 4A Executive Officers of the Registrant.
We have adopted a Code of Ethics for Financial Officers, which applies to our principal executive officer, president, principal financial officer, principal accounting officer or controller, or persons performing similar functions. The information set forth under Item 1 hereof concerning the Code of Ethics for Financial Officers is filed herewith.

ITEM 11. EXECUTIVE COMPENSATION.
The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned “Director Compensation,” “Executive Compensation” and “Compensation Discussion and Analysis” in the Proxy Statement to be filed no later than March 31, 2016, in connection with our Annual Meeting to be held on or about May 6, 2016.

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 portion of the Proxy Statement, captioned “Security Ownership of Certain Beneficial Owners and Management” to be filed no later than March 31, 2016, in connection with our Annual Meeting to be held on or about May 6, 2016.

The following table sets forth information, as of December 31, 2015, with respect to our SICP, under which shares of Chesapeake Utilities common stock are authorized for issuance:

	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	—	—	575,473
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	575,473

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

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement captioned, “Corporate Governance,” to be filed no later than March 31, 2016 in connection with our Annual Meeting to be held on or about May 6, 2016.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

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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," to be filed no later than March 31, 2016, in connection with our Annual Meeting to be held on or about May 6, 2016.

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 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 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.†

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• 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, dated January 1, 2005, is incorporated herein by reference to Exhibit 10.3 of our Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-11590.
• Exhibit 10.2*	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 10.3*	Chesapeake Utilities Corporation Directors Stock Compensation Plan, effective May 5, 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
• Exhibit 10.4*	Chesapeake Utilities Corporation Employee Stock Award Plan, effective May 5, 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.

• Exhibit 10.5*	Chesapeake Utilities Corporation Performance Incentive Plan, effective May 5, 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
• Exhibit 10.6*	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 10.7*	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 10.8*	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 10.9*	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 10.10*	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.

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• Exhibit 10.11*	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 10.12*	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 10.13*	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 10.14*	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 10.15*	Form of Performance Share Agreement, effective January 8, 2013 for the period 2013 to 2015, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.15 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.16*	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 10.17*	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 10.18*	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 10.19*	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 10.20*	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 10.21*	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 10.22	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 10.23	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.

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• Exhibit 10.24	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 10.25	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 12	Computation of Ratio of Earning to Fixed Charges is filed herewith.
• Exhibit 14.1	Code of Ethics for Financial Officers is filed herewith.
• Exhibit 14.2	Business Code of Ethics and Conduct is filed herewith.
• Exhibit 21	Subsidiaries of the Registrant is filed herewith.
• Exhibit 23.1	Consent of Independent Registered Public Accounting Firm is filed herewith.
• Exhibit 31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), dated February 26, 2016, 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), dated February 26, 2016, is filed herewith.
• Exhibit 32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated February 26, 2016 is filed herewith.
• Exhibit 32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated February 26, 2016, 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.

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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
Date: February 26, 2016

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/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Chair of the Board and Director
Date: February 26, 2016

/S/ RALPH J. ADKINS
Ralph J. Adkins,
Chair Emeritus and Director
Date: February 26, 2016

/S/ MICHAEL P. MCMASTERS
Michael P. McMasters,
President, Chief Executive Officer and Director
Date: February 26, 2016

/S/ BETH W. COOPER
Beth W. Cooper, Senior Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)
Date: February 26, 2016

/S/ EUGENE H. BAYARD,ESQ
Eugene H. Bayard, Esq., Director
Date: February 26, 2016

/S/ RICHARD BERNSTEIN
Richard Bernstein, Director
Date: February 26, 2016

/S/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
Date: February 26, 2016

/S/ RONALD G. FORSYTHE, JR.
Dr. Ronald G. Forsythe, Jr., Director
Date: February 26, 2016

/S/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
Date: February 26, 2016

/S/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
Date: February 26, 2016

/S/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
Date: February 26, 2016

/S/ JOSEPH E. MOORE, ESQ
Joseph E. Moore, Esq., Director
Date: February 26, 2016

/S/ CALVERT A. MORGAN, JR.
Calvert A. Morgan, Jr., Director
Date: February 26, 2016

/S/ DIANNA F. MORGAN
Dianna F. Morgan, Director
Date: February 26, 2016

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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 26, 2016 relating to the consolidated financial statements of Chesapeake Utilities Corporation (the "Company") as of December 31, 2015 and 2014 and for each of the years in the three-year period ended December 31, 2015, 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 26, 2016

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Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions		Deductions [2]	Balance at End of Year
		Charged to Income	Other Accounts [1]		
(In thousands)					
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
2015	$1,120	$979	$246	(1,436)	$909
2014	$1,635	$1,073	$85	(1,673)	$1,120
2013	$826	$1,796	$249	(1,236)	$1,635

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