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Ohio | Public Utilities Commission

PUCO USE ONLY - Version 1.08 May 2016		
Date Received	Renewal Certification Number	ORIGINAL CRS Case Number
		17 - 1916 - GA-CRS

FILE

RENEWAL CERTIFICATION APPLICATION COMPETITIVE RETAIL NATURAL GAS SUPPLIERS

Please **type or print** all required information. Identify all attachments with an exhibit label and title (***Example: Exhibit A-15 - Company History***). All attachments should bear the legal name of the Applicant. Applicants should file completed applications and all related correspondence with the Public Utilities Commission of Ohio, Docketing Division, 180 East Broad Street, Columbus, Ohio 43215-3793.

This PDF form is designed so that you may directly input information onto the form. You may also download the form by saving it to your local disk.

SECTION A - APPLICANT INFORMATION AND SERVICES

A-1 Applicant intends to renew its certificate as: (check all that apply)

☐ **Retail Natural Gas Aggregator** ☐ **Retail Natural Gas Broker** ☑ **Retail Natural Gas Marketer**

A-2 Applicant information:

Legal Name: Peninsula Energy Services Company, Inc.

Address: 331 West Central Ave., Suite 200, Winter Haven, FL 33880

Telephone No. 863-845-7004 Web site Address www.pescoenergy.com

Current PUCO Certificate No. 17-620G(1) Effective Dates 10/6/17 through 10/6/19

A-3 Applicant information under which applicant will do business in Ohio:

Name: Peninsula Energy Services Company, Inc.

Address: 331 West Central Ave., Suite 200, Winter Haven, FL 33880

Web site Address www.pescoenergy.com Telephone No. 302-242-9793

2019 SEP -6 PM 2:19 PUCO

RECEIVED-DOCKETING DIV

A-4 List all names under which the applicant does business in North America:

Peninsula Energy Services Company, Inc.

PESCO

PESCO Energy

A-5 Contact person for regulatory or emergency matters:

Name Al Gallo Title Assistant Vice President

Business Address 100 Commerce Drive, Suite 200, Newark, DE 19713

Telephone No. 302-736-7621 Fax No. 302-744-2227 Email Address PescoOpsTeam@chpk.com

This is to certify that the images appearing are an accurate and complete reproduction of a case file document delivered in the regular course of business. Technician AM Date Processed 9/6/19

A-6 Contact person for Commission Staff use in investigating customer complaints:

Name Kimberly McCarty Title Supervisor, Customer Support

Business address 331 W Central Ave Suite 200 Winter Haven, FL 33880

Telephone No. 863-845-7004 Fax No. Email Address kamccarty@pescoenergy.com

A-7 Applicant's address and toll-free number for customer service and complaints

Customer service address 331 W Central Ave Suite 200 Winter Haven, FL 33880

Toll-Free Telephone No. 1-855-737-2600 Fax No. Email Address kamccarty@pescoenergy.co

A-8 Provide "Proof of an Ohio Office and Employee," in accordance with Section 4929.22 of the Ohio Revised Code, by listing name, Ohio office address, telephone number, and Web site address of the designated Ohio Employee

Name Gwen Kyle Title Manager of Origination, Midwest

Business address 1088 Sagecrest Drive, Columbus OH 43229

Telephone No. 302-242-9793 Fax No. 302-744-2227 Email Address gkyle@pescoenergy.com

A-9 Applicant's federal employer identification number 20-2017183

A-10 Applicant's form of ownership: (Check one)

☐ **Sole Proprietorship** ☐ **Partnership**

☐ **Limited Liability Partnership (LLP)** ☐ **Limited Liability Company (LLC)**

☑ **Corporation** ☐ **Other**

A-11 (Check all that apply) Identify each natural gas company service area in which the applicant is currently providing service or intends to provide service, including identification of each customer class that the applicant is currently serving or intends to serve, for example: *residential, small commercial, and/or large commercial/industrial (mercantile) customers.* (A mercantile customer, as defined in Section 4929.01(L)(1) of the Ohio Revised Code, means a customer that consumes, other than for residential use, more than 500,000 cubic feet of natural gas per year at a single location within the state or consumes natural gas, other than for residential use, as part of an undertaking having more than three locations within or outside of this state. In accordance with Section 4929.01(L)(2) of the Ohio Revised Code, "Mercantile customer" excludes a not-for-profit customer that consumes, other than for residential use, more than 500,000 cubic feet of natural gas per year at a single location within this state or consumes natural gas, other than for residential use, as part of an undertaking having more than three locations within or outside this state that has filed the necessary declaration with the Public Utilities Commission.)

✓	Columbia Gas of Ohio	☐ Residential	✓ Small Commercial	✓ Large Commercial / Industrial
✓	Dominion East Ohio	☐ Residential	✓ Small Commercial	✓ Large Commercial / Industrial
☐	Duke Energy Ohio	☐ Residential	☐ Small Commercial	☐ Large Commercial / Industrial
☐	Vectren Energy Delivery of Ohio	☐ Residential	☐ Small Commercial	☐ Large Commercial / Industrial

A-12 If applicant or an affiliated interest previously participated in any of Ohio's Natural Gas Choice Programs, for each service area and customer class, provide approximate start date(s) and/or end date(s) that the applicant began delivering and/or ended services.

☑ Columbia Gas of Ohio

☐	Residential	Beginning Date of Service	End Date
✓	Small Commercial	Beginning Date of Service	End Date
✓	Large Commercial	Beginning Date of Service	End Date
✓	Industrial	Beginning Date of Service	End Date

☑ Dominion East Ohio

☐	Residential	Beginning Date of Service	End Date
✓	Small Commercial	Beginning Date of Service	End Date
✓	Large Commercial	Beginning Date of Service	End Date
✓	Industrial	Beginning Date of Service	End Date

☐ Duke Energy Ohio

☐	Residential	Beginning Date of Service	End Date
☐	Small Commercial	Beginning Date of Service	End Date
☐	Large Commercial	Beginning Date of Service	End Date
☐	Industrial	Beginning Date of Service	End Date

☐ Vectren Energy Delivery of Ohio

☐	Residential	Beginning Date of Service	End Date
☐	Small Commercial	Beginning Date of Service	End Date
☐	Large Commercial	Beginning Date of Service	End Date
☐	Industrial	Beginning Date of Service	End Date

A-13 If not currently participating in any of Ohio's four Natural Gas Choice Programs, provide the approximate start date that the applicant proposes to begin delivering services:

☐	Columbia Gas of Ohio	Intended Start Date
☐	Dominion East Ohio	Intended Start Date
☐	Duke Energy Ohio	Intended Start Date
☐	Vectren Energy Delivery of Ohio	Intended Start Date

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED.

A-14 **Exhibit A-14 "Principal Officers, Directors & Partners,"** provide the names, titles, addresses and telephone numbers of the applicant's principal officers, directors, partners, or other similar officials.

A-15 **Exhibit A-15 "Company History,"** provide a concise description of the applicant's company history and principal business interests.

A-16 **Exhibit A-16 "Articles of Incorporation and Bylaws**, provide the articles of incorporation filed with the state or jurisdiction in which the applicant is incorporated and any amendments thereto, ***only if the contents of the originally filed documents changed since the initial application.***

A-17 **Exhibit A-17 "Secretary of State,"** provide evidence that the applicant is still currently registered with the Ohio Secretary of the State.

SECTION B - APPLICANT MANAGERIAL CAPABILITY AND EXPERIENCE

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED

B-1 **Exhibit B-1 "Jurisdictions of Operation,"** provide a current list of all jurisdictions in which the applicant or any affiliated interest of the applicant is, at the date of filing the application, certified, licensed, registered, or otherwise authorized to provide retail natural gas service, or retail/wholesale electric services.

B-2 **Exhibit B-2 "Experience & Plans,"** provide a current description of the applicant's experience and plan for contracting with customers, providing contracted services, providing billing statements, and responding to customer inquiries and complaints in accordance with Commission rules adopted pursuant to Section 4929.22 of the Revised Code and contained in Chapter 4901:1-29 of the Ohio Administrative Code.

B-3 **Exhibit B-3 "Summary of Experience,"** provide a concise and current summary of the applicant's experience in providing the service(s) for which it is seeking renewed certification (e.g., number and types of customers served, utility service areas, volume of gas supplied, etc.).

B-4 **Exhibit B-4 "Disclosure of Liabilities and Investigations,"** provide a description of all existing, pending or past rulings, judgments, contingent liabilities, revocations of authority, regulatory investigations, or any other matter that could adversely impact the applicant's financial or operational

status or ability to provide the services for which it is seeking renewed certification since applicant last filed for certification.

B-5 **Exhibit B-5 "Disclosure of Consumer Protection Violations,"** disclose whether the applicant, affiliate, predecessor of the applicant, or any principal officer of the applicant has been convicted or held liable for fraud or for violation of any consumer protection or antitrust laws since applicant last filed for certification.

☑ **No** ☐ **Yes**

If Yes, provide a separate attachment labeled as Exhibit B-5 "Disclosure of Consumer Protection Violations," detailing such violation(s) and providing all relevant documents.

B-6 **Exhibit B-6 "Disclosure of Certification Denial, Curtailment, Suspension, or Revocation,"** disclose whether the applicant or a predecessor of the applicant has had any certification, license, or application to provide retail natural gas or retail/wholesale electric service denied, curtailed, suspended, or revoked, or whether the applicant or predecessor has been terminated from any of Ohio's Natural Gas Choice programs, or been in default for failure to deliver natural gas since applicant last filed for certification.

☑ **No** ☐ **Yes**

If Yes, provide a separate attachment, labeled as Exhibit B-6 "Disclosure of Certification Denial, Curtailment, Suspension, or Revocation," detailing such action(s) and providing all relevant documents.

SECTION C - APPLICANT FINANCIAL CAPABILITY AND EXPERIENCE

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED

C-1 **Exhibit C-1 "Annual Reports,"** provide the two most recent Annual Reports to Shareholders. If applicant does not have annual reports, the applicant should provide similar information, labeled as Exhibit C-1, or indicate that Exhibit C-1 is not applicable and why.
(This is generally only applicable to publicly traded companies who publish annual reports.)

C-2 **Exhibit C-2 "SEC Filings,"** provide the most recent 10-K/8-K Filings with the SEC. If applicant does not have such filings, it may submit those of its parent company. An applicant may submit a current link to the filings or provide them in paper form. If the applicant does not have such filings, then the applicant may indicate in Exhibit C-2 that the applicant is not required to file with the SEC and why.

C-3 **Exhibit C-3 "Financial Statements,"** provide copies of the applicant's two most recent years of audited financial statements (balance sheet, income statement, and cash flow statement). If audited financial statements are not available, provide officer certified financial statements. If the applicant has not been in business long enough to satisfy this requirement, it shall file audited or officer certified financial statements covering the life of the business. If the applicant does not have a balance sheet, income statement, and cash flow statement, the applicant may provide a copy of its two most recent years of tax returns (with social security numbers and account numbers redacted).

C-4 **Exhibit C-4 "Financial Arrangements,"** provide copies of the applicant's current financial arrangements to conduct competitive retail natural gas service (CRNGS) as a business activity (e.g., guarantees, bank commitments, contractual arrangements, credit agreements, etc.)

Renewal applicants can fulfill the requirements of Exhibit C-4 by providing a current statement from an Ohio local distribution utility (LDU) that shows that the applicant meets the LDU's collateral requirements.

First time applicants or applicants whose certificate has expired as well as renewal applicants can meet the requirement by one of the following methods:

1. The applicant itself stating that it is investment grade rated by Moody's, Standard & Poor's or Fitch and provide evidence of rating from the rating agencies.

2. Have a parent company or third party that is investment grade rated by Moody's, Standard & Poor's or Fitch guarantee the financial obligations of the applicant to the LDU(s).

3. Have a parent company or third party that is not investment grade rated by Moody's, Standard & Poor's or Fitch but has substantial financial wherewithal in the opinion of the Staff reviewer to guarantee the financial obligations of the applicant to the LDU(s). The guarantor company's financials must be included in the application if the applicant is relying on this option.

4. Posting a Letter of Credit with the LDU(s) as the beneficiary.

If the applicant is not taking title to the electricity or natural gas, enter "N/A "in Exhibit C-4. An N/A response is only applicable for applicants seeking to be certified as an aggregator or broker.

C-5 **Exhibit C-5 "Forecasted Financial Statements,"** provide two years of forecasted income statements for the applicant's **NATURAL GAS related business activities in the state of Ohio Only**, along with a list of assumptions, and the name, address, email address, and telephone number of the preparer. The forecasts should be in an annualized format for the two years succeeding the Application year.

C-6 **Exhibit C-6 "Credit Rating,"** provide a statement disclosing the applicant's current credit rating as reported by two of the following organizations: Duff & Phelps, Fitch IBCA, Moody's Investors Service, Standard & Poor's, or a similar organization. In instances where an applicant does not have its own credit ratings, it may substitute the credit ratings of a parent or an affiliate organization, provided the applicant submits a statement signed by a principal officer of the applicant's parent or affiliate organization that guarantees the obligations of the applicant. If an applicant or its parent does not have such a credit rating, enter "N/A" in Exhibit C-6.

C-7 **Exhibit C-7 "Credit Report,"** provide a copy of the applicant's current credit report from Experion, Dun and Bradstreet, or a similar organization. An applicant that provides an investment grade credit rating for Exhibit C-6 may enter "N/A" for Exhibit C-7.

C-8 **Exhibit C-8 "Bankruptcy Information,"** provide a list and description of any reorganizations, protection from creditors, or any other form of bankruptcy filings made by the applicant, a parent or affiliate organization that guarantees the obligations of the applicant or any officer of the applicant in the current year or within the two most recent years preceding the application.

C-9 **Exhibit C-9 "Merger Information,"** provide a statement describing any dissolution or merger or acquisition of the applicant within the two most recent years preceding the application.

C-10 **Exhibit C-10 "Corporate Structure,"** provide a description of the applicant's corporate structure, not an internal organizational chart, including a graphical depiction of such structure, and a list of all affiliate and subsidiary companies that supply retail or wholesale electricity or natural gas to customers in North America. If the applicant is a stand-alone entity, then no graphical depiction is required and applicant may respond by stating that they are a stand-alone entity with no affiliate within the two most recent years preceding the application.

SECTION D – APPLICANT TECHNICAL CAPABILITY

PROVIDE THE FOLLOWING AS SEPARATE ATTACHMENTS AND LABEL AS INDICATED.

D-1 **Exhibit D-1 "Operations,"** provide a current written description of the operational nature of the applicant's business. Please include whether the applicant's operations will include the contracting of natural gas purchases for retail sales, the nomination and scheduling of retail natural gas for delivery, and the provision of retail ancillary services, as well as other services used to supply natural gas to the natural gas company city gate for retail customers.

D-2 **Exhibit D-2 "Operations Expertise,"** given the operational nature of the applicant's business, provide evidence of the applicant's current experience and technical expertise in performing such operations.

D-3 **Exhibit D-3 "Key Technical Personnel,"** provide the names, titles, email addresses, telephone numbers, and background of key personnel involved in the operational aspects of the applicant's current business.

Applicant Signature and Title Assistant Vice President

Sworn and subscribed before me this 5th **day of** September **Month** 2019 **Year**

Signature of official administering oath

Print Name and Title Loralyn K. Hayes

My commission expires on

LORALYN K. HAYES
Notary Public - State of Florida
Commission # GG 038555
My Comm. Expires Nov 8, 2020

The Public Utilities Commission of Ohio

Competitive Retail Natural Gas Service
Affidavit Form
(Version 1.07)

In the Matter of the Application of)
Peninsula Energy Services Company, Inc.)
for a Certificate or Renewal Certificate to Provide)
Competitive Retail Natural Gas Service in Ohio.)

Case No. 17 - 1916 **-GA-CRS**

County of Franklin
State of Ohio

[Affiant], being duly sworn/affirmed, hereby states that:

(1) The information provided within the certification or certification renewal application and supporting information is complete, true, and accurate to the best knowledge of affiant.

(2) The applicant will timely file an annual report of its intrastate gross receipts and sales of hundred cubic feet of natural gas pursuant to Sections 4905.10(A), 4911.18(A), and 4929.23(B), Ohio Revised Code.

(3) The applicant will timely pay any assessment made pursuant to Section 4905.10 or Section 4911.18(A), Ohio Revised Code.

(4) Applicant will comply with all applicable rules and orders adopted by the Public Utilities Commission of Ohio pursuant to Title 49, Ohio Revised Code.

(5) Applicant will cooperate with the Public Utilities Commission of Ohio and its staff in the investigation of any consumer complaint regarding any service offered or provided by the applicant.

(6) Applicant will comply with Section 4929.21, Ohio Revised Code, regarding consent to the jurisdiction of the Ohio courts and the service of process.

(7) Applicant will inform the Public Utilities Commission of Ohio of any material change to the information supplied in the certification or certification renewal application within 30 days of such material change, including any change in contact person for regulatory or emergency purposes or contact person for Staff use in investigating customer complaints.

(8) Affiant further sayeth naught.

Affiant Signature & Title Assistant Vice President

Sworn and subscribed before me this 5th **day of** September **Month** 2019 **Year**

Loralyn K. Hayes

Signature of Official Administering Oath

Loralyn K. Hayes

Print Name and Title

LORALYN K. HAYES
Notary Public - State of Florida
Commission # GG 038555
My Comm. Expires Nov 8, 2020

My commission expires on

180 East Broad Street • Columbus, OH 43215-3793 • (614) 466-3016 • www.PUCO.ohio.gov
The Public Utilities Commission of Ohio is an Equal Opportunity Employer and Service Provider

Renewal Certification Application
Competitive Retail Natural Gas Suppliers

Case No.: 17-1916-GA-CRS
Peninsula Energy Services Company, Inc.

Exhibit A-14 "Principal Officers, Directors, & Partners"

Chesapeake Utilities Corporation owns 100% of PESCO's stock. The directors of PESCO are listed below.

- Eugene H. Bayard
- Thomas J. Bresnan
- Ronald G. Forsythe, Jr.
- Jeffry M. Householder
- Thomas P. Hill, Jr.
- Dennis S. Hudson, III
- Paul L. Maddock, Jr.
- Calvert A. Morgan, Jr.
- Dianna F. Morgan
- John R. Schimkaitis

PESCO's Management Team:

Al Gallo, Assistant Vice President, Optimization
Peninsula Energy Services Company, Inc.
100 Commerce Drive, Suite 200
Newark, DE 19713
302-736-7621

Bill Hancock, Assistant Vice President, Origination
Peninsula Energy Services Company, Inc.
331 West Central Ave, Suite 200
Winter Haven, FL 33880
302-242-2855

Marissa Stipa, Director, Optimization
Peninsula Energy Services Company, Inc.
100 Commerce Drive, Suite 200
Newark, DE 19713
302-213-7518

Steve Smith, Director, Financial Analysis
Peninsula Energy Services Company, Inc.
100 Commerce Drive, Suite 200
Newark, DE 19713
302-213-7517

Exhibit A-15 "Company History"

Chesapeake's family of regulated and unregulated energy companies began in 1859 as Dover Light Company, a gas company located in Dover DE. Chesapeake Utilities Corporate was incorporated in Delaware in 1947 and now includes natural gas distribution and transmission operations in the Delmarva Peninsula and Florida, and electric distribution operations in Florida. Chesapeake's unregulated energy businesses include its natural gas marketing subsidiary, PESCO, operating in these same regions and also markets natural gas supply in the states of Ohio, Pennsylvania, and West Virginia. Additional diversity in Chesapeake's unregulated businesses exists in its natural gas midstream services entity, Aspire Energy, with over 2,700 miles of pipeline systems in 40 counties throughout Ohio and its propane distribution and wholesale marketing subsidiary, Sharp Energy. A propane supplier to the Delmarva region, Pennsylvania and Florida.

A wholly-owned subsidiary of Chesapeake Utilities Corporation (CUC) whose heritage stretches more than 150 years, PESCO has been in continuous operation since 1994 with extensive experience in retail and wholesale supply, transportation, and distribution of natural gas. For twenty-five years, PESCO has employed highly-experienced industry personnel to proudly serve customers in each of the markets we operate dedicated to the needs of our customers and who work within the natural gas market every day interacting with regulated and unregulated counterparts on behalf of our customers. PESCO's focus as a natural gas supplier in the footprint where our utilities, pipelines, gathering systems, propane distribution, and auto-gas supply entities reside is a solid complement to the diversified energy company Chesapeake Utilities has grown to become and strives to expand.

Exhibit A-16 "Articles of Incorporation and Bylaws"

Delaware

PAGE 1

The First State

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED ARE TRUE AND CORRECT COPIES OF ALL DOCUMENTS ON FILE OF "PENINSULA ENERGY SERVICES COMPANY, INC." AS RECEIVED AND FILED IN THIS OFFICE.

THE FOLLOWING DOCUMENTS HAVE BEEN CERTIFIED:

CERTIFICATE OF INCORPORATION, FILED THE THIRTIETH DAY OF SEPTEMBER, A.D. 2004, AT 6:17 O'CLOCK P.M.

CERTIFICATE OF MERGER, FILED THE TENTH DAY OF AUGUST, A.D. 2005, AT 5:52 O'CLOCK P.M.

CERTIFICATE OF MERGER, FILED THE TENTH DAY OF AUGUST, A.D. 2005, AT 5:52 O'CLOCK P.M.

AND I DO HEREBY FURTHER CERTIFY THAT THE AFORESAID CERTIFICATES ARE THE ONLY CERTIFICATES ON RECORD OF THE AFORESAID CORPORATION, "PENINSULA ENERGY SERVICES COMPANY, INC.".

Harriet Smith Windsor

Harriet Smith Windsor, Secretary of State

3855588 8100H

080288244

AUTHENTICATION: 6429488

DATE: 03-06-08

You may verify this certificate online at corp.delaware.gov/authver.shtml

Exhibit A-16 "Articles of Incorporation and Bylaws", continued

CERTIFICATE OF INCORPORATION

FIRST: The name of this corporation shall be: Peninsula Energy Services Company, Inc.

SECOND: Its registered office in the State of Delaware is to be located at 2711 Centerville Road, Suite 400, in the City of Wilmington, County of New Castle and its registered agent at such address is CORPORATION SERVICE COMPANY.

THIRD: The purpose or purposes of the corporation shall be:

> To engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of Delaware.

FOURTH: The total number of shares of stock which this corporation is authorized to issue is: 100 shares of common stock with a par value of $.01 per share.

FIFTH: The name and address of the incorporator is as follows: Beth W. Cooper, 909 Silver Lake Boulevard, Dover, Delaware 19904.

SIXTH: The Board of Directors shall have the power to adopt, amend or repeal the by-laws.

SEVENTH: No director shall be personally liable to the Corporation or its stockholders for monetary damages for any breach of fiduciary duty by such director as a director. Notwithstanding the foregoing sentence, a director shall be liable to the extent provided by applicable law, (i) for breach of the director's duty of loyalty to the Corporation or its stockholders, (ii) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (iii) pursuant to Section 174 of the Delaware General Corporation Law or (iv) for any transaction from which the director derived an improper personal benefit. No amendment to or repeal of this Article Seventh shall apply to or have any effect on the liability or alleged liability of any director of the Corporation for or with respect to any acts or omissions of such director occurring prior to such amendment.

IN WITNESS WHEREOF, the undersigned, being the incorporator herein before named, has executed signed and acknowledged this certificate of incorporation this 30th day of September, A.D. 2004.

Beth W. Cooper

State of Delaware
Secretary of State
Division of Corporations
Delivered 06:37 PM 09/30/2004
FILED 06:17 PM 09/30/2004
SRV 040709919 - 3855568 FILE

Exhibit A-17 "Secretary of State"

STATE OF OHIO
CERTIFICATE

Ohio Secretary of State, Jon Husted

2387617

It is hereby certified that the Secretary of State of Ohio has custody of the business records for

PENINSULA ENERGY SERVICE COMPANY, INC.

and, that said business records show the filing and recording of:

Document(s)	Document No(s):
FOREIGN LICENSE/FOR-PROFIT	**201511700744**

Effective Date: 04/24/2015

Authorization to transact business in Ohio is hereby given, until surrender, expiration or cancellation of this license.

Witness my hand and the seal of the Secretary of State at Columbus, Ohio this 27th day of April, A.D. 2015.

United States of America
State of Ohio
Office of the Secretary of State

Jon Husted

Ohio Secretary of State

Exhibit B-1 "Jurisdictions of Operations"

PESCO currently serves approximately 3500 commercial and industrial customers in 6 states. This represents approximately 41.0 Bcf of natural gas annually. Specifically, PESCO provides natural gas to customers on the following systems:

- *Florida:* Peoples Gas, Florida City Gas, Central Florida Gas, Florida Public Utilities, Lake Apopka Natural Gas District, Sebring Natural Gas, Indiantown Natural Gas, Lake City Natural Gas, Florida Gas Transmission
- *Delaware:* Chesapeake Utilities Delaware Division, Delmarva Natural Gas, Eastern Shore Natural Gas, Delmarva Power
- *Maryland:* Chesapeake Utilities Maryland Division, Eastern Shore Natural Gas, Delmarva Power, Baltimore Gas and Electric
- *Ohio:* Columbia Gas of Ohio, Dominion East Ohio
- *Pennsylvania:* Columbia Gas of Pennsylvania, Peoples Natural Gas, People Equitable Division, Peoples TWP Division, PECO Energy Company
- *West Virginia:* Mountaineer Gas Company, Dominion Hope Gas

PESCO has jurisdictional authority certificates in each of the above states. Our jurisdictional authority has never been denied, suspended, revoked, or sanctioned.

Exhibit B-2 "Experience & Plans"

PESCO contracts with every customer in written form outlining General Terms and Conditions of each transaction and detailing the specifics of each supply transaction with a Transaction Confirmation. For customers who prefer to use the NAESB, PESCO will contract under that document with Special Provisions Agreeable to both parties. PESCO intends to contract in written form with each customer going forward. PESCO does not pursue residential Choice customers who may use telephonic authorizations to contract.

Each PESCO customer is provided a monthly billing statement for supplied volumes from PESCO consistent with the terms of each supply agreement. Commercial Choice customers are generally invoiced through the utility. PESCO has a fully-staffed customer service department to respond to customer inquiries and complaints. Our customer service toll-free number is provided to each customer and included on each invoice.

Each PESCO contract clearly specifies and includes the following items, consistent with the requirements of the Commission, ORC and OAC:

- Transaction Date
- Transaction Number
- Buyer Name, Address, Phone, Fax, Email with Corresponding Signature Blocks
- Seller Name, Address, Phone, Fax, Email, with Corresponding Signature Blocks
- Facility Address(es) and Utility Account Number(s)
- Contract Quantity and Units of Measure
- Contract Price (Fixed or Variable) per Unit
- Delivery Point (LDC or Pipeline)
- Delivery Period (Start and End Month)
- Special Provisions Section to Include Swing Language (when applicable)
- Addendum to Transaction Confirmation (when applicable to list multiple accounts per transaction)
- Renewal Term Language with Auto-Renewal Provisions
- Notification to Cancel Period, Right to Cancel, and Early Termination
- Nomination and Balancing Provisions
- Operational Flow Order Responsibilities (where applicable)
- Performance Clause and Transportation Obligations
- Language to Address Tariff and Regulatory Changes
- Pricing for Rollover Periods
- Taxes
- Billing and Payment Terms
- Events of Default; Remedy for Failure of Either Party to Perform
- Force Majeure Language
- Credit Terms
- Risk of Loss; Warranty; Indemnity; Damages
- Assignment Provisions
- Quality and Measurement of Natural Gas
- Priority; Choice of Law; Dispute Resolution
- Severability
- Forward Contract Statement
- Third Party Beneficiary; Waiver; Construction; Entire Agreement Clauses

Exhibit B-3 "Summary of Experience"

PESCO's less than five years as a competitive retail natural gas supplier in the Ohio market is much shorter than our experience providing similar services in our other markets. However, PESCO has brought prior expertise from our other markets to establish a solid and highly-respected supplier option to Ohio's natural gas customers. PESCO has performed its services well and without issue since our initial Certification as a competitive retail natural gas supplier was granted by the PUCO. In just a few years, PESCO has grown its Commercial and Industrial customer base in Ohio managing Choice and GTS pools behind both DEO and COH as well as supplying to stand-alone customers.

Below is a summary of PESCO's market in Ohio for Calendar Year 2018 and projected numbers for 2019.

COH

2018	Accounts	Annual Volumes
CHOICE:	376	619,183 Mcf
GTS:	15	751,278 Mcf

2019 Projected	*Accounts*	*Annual Volumes*
CHOICE:	475	750,000 Mcf
GTS:	50	950,000 Mcf

DEO

2018	Accounts	Annual Volumes
CHOICE:	87	35,017 Mcf
GTS:	6	261,537 Mcf

2019 Projected	*Accounts*	*Annual Volumes*
CHOICE:	250	260,000 Mcf
GTS:	15	4,000,000 Mcf

PESCO is well-positioned for growth in the Ohio market and appropriately staffed with industry experts highly-experienced in serving Ohio customers.

Exhibit B-4 "Disclosure of Liabilities and Investigations"

There have been no existing, pending, or past liabilities or investigations, regulatory or other, since Peninsula Energy Services Company's last filing for certification.

Exhibit C-1 "Annual Reports"

Please refer to the Annual Reports (and/or 10-K SEC filings) that are submitted separately as a response. Further financial information and filings can be found on our corporate website at the link below.

http://investor.chpk.com/financial-information/sec-filings

Exhibit C-2 "SEC Filings"

Please refer to the Annual Reports (and/or 10-K SEC filings) that are submitted separately as a response. *Further financial information and filings can be found on our corporate website at the link below.*

http://investor.chpk.com/financial-information/sec-filings

Exhibit C-3 "Financial Statements"

Please refer to the audited financial statements that are submitted separately as a response.

Exhibit C-4 "Financial Arrangements"

The enclosed Guaranty Agreement between East Ohio Gas Company (DEO) and Chesapeake Utilities Corporation, Peninsula Energy Services Company parent, serves as current financial arrangements to conduct competitive retail natural gas service in Ohio. A similar Guaranty Agreement is in place with Columbia Gas.

GUARANTY AGREEMENT

This Guaranty Agreement (the "Guaranty") is made by Chesapeake Utilities Corporation ("Guarantor"), a Delaware Corporation, in favor of Peninsula Energy Services Company, Inc. ("Company").

WHEREAS, East Ohio Gas Company "(Counterparty") and Company are or may become parties to commodity-related physical and financial transactions and agreements (collectively, whether one or more, the "Agreement" or "Agreements"); and

WHEREAS, the Guarantor is the direct or indirect parent of Company, and will receive substantial and direct benefits from the transactions contemplated by the Agreement and has agreed to enter into this Guaranty to provide assurance for the payment obligations of Company in connection with the Agreement and to induce the Counterparty to enter into the Agreement.

NOW, THEREFORE, in consideration of good and valuable consideration, the adequacy, receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby agrees as follows:

1. Guaranty. The Guarantor hereby unconditionally, irrevocably and absolutely guarantees the punctual payment when due (subject to written demand in accordance with Paragraph 6 below) of Company's payment obligations arising under any Agreement with payment terms of less than 365 days for any individual obligation/invoice, as such Agreement may be amended or modified by agreement between Company and the Counterparty from time to time (collectively, the "Guaranteed Obligations"); provided, however, that the total liability of the Guarantor hereunder, regardless of any amendment or modification to any Agreement, is limited to the lesser of (a) the Guaranteed Obligations under all Agreements or (b) US$200,000.00 (Two Hundred Thousand Dollars), plus all interest, reasonable attorneys' fees, and/or costs of collection, if any, required by such Agreement to be paid by Company in the collection of Guaranteed Obligations. In addition, subject to the limitations above, Guarantor shall reimburse Counterparty for all sums paid to Counterparty by Company with respect to such Guaranteed Obligations which Counterparty is subsequently required to return to Company or a representative of Company's creditors as a result of Company's bankruptcy, insolvency, reorganization, liquidation, receivership, or similar proceeding. The Guarantor's obligations and liability under this Guaranty shall be limited to payment obligations only and the Guarantor shall have no obligation to perform under any Agreement, including, without limitation, to sell, deliver, supply or transport gas, electricity or any other commodity.

   If all or a part of any payment made by Guarantor to Counterparty hereunder is later determined to have been improper because such amount was not actually owed by Company to Counterparty under the Agreement or such payment was otherwise unjustified, Counterparty shall repay such amount to Guarantor within twenty (20) business days of written demand by Guarantor together with any interest, reasonable attorneys' fees, and/or costs of collection, if any, required by the Agreement to be paid by Counterparty in the collection of such amount.

Exhibit C-4 "Financial Arrangements", continued (Guaranty Agreement, p.2)

2. **Guaranty Absolute.** The liability of Guarantor under this Guaranty shall be absolute, irrevocable and unconditional irrespective of:

(a) any modification, extension or waiver of any of the terms of any Agreement;

(b) any change in the time, manner, terms or place of payment of or in any other term of, all or any of the Guaranteed Obligations, or any other amendment or waiver of or any consent to departure from any Agreement or any other agreement or instrument executed in connection therewith;

(c) any sale, exchange, release or non-perfection of any property standing as security for the liabilities hereby guaranteed or any liabilities incurred directly or indirectly hereunder or any setoff against any of said liabilities, or any release or amendment or waiver of or consent to departure from any other guaranty, for all or any of the Guaranteed Obligations; or

(d) any change in the existence, structure or ownership of the Guarantor or Company, or any bankruptcy, insolvency, reorganization, liquidation, receivership, or similar proceeding affecting Company or its assets.

The obligations of the Guarantor hereunder are several and not joint with Company or any other person, and are primary obligations for which the Guarantor is the principal obligor. There are no conditions precedent to the enforcement of this Guaranty, except as expressly contained herein. It shall not be necessary for the Counterparty, in order to enforce payment by the Guarantor under this Guaranty, to exhaust its remedies against Company, any collateral pledged by Company, any other guarantor, or any other person liable for the payment or performance of the Guaranteed Obligations. This Guaranty is one of payment and not of collection and shall apply regardless of whether recovery of all such Guaranteed Obligations may be discharged, or uncollectible in any bankruptcy, insolvency, reorganization, liquidation, receivership, or similar proceeding affecting Company or its assets.

Without limiting Guarantor's own defenses and rights hereunder, Guarantor reserves to itself all rights, setoffs, counterclaims and other defenses to which Company is or may be entitled to arising from or out of the Agreements or otherwise, except as limited herein and except for defenses arising out of the bankruptcy, insolvency, reorganization, liquidation, receivership, or similar proceeding affecting Company or its assets.

3. **Waiver.** Guarantor hereby waives:

(a) notice of acceptance of this Guaranty, notice of the creation or existence of any of the Guaranteed Obligations and notice of any action by the Counterparty in reliance hereon or in connection herewith;

(b) notice of the entry into any Agreement between Company and the Counterparty and notice of any amendments, supplements or modifications thereto; or any

Exhibit C-4 "Financial Arrangements", continued (Guaranty Agreement, p.3)

waiver of consent under any Agreement, including waivers of the payment and performance of the obligations thereunder;

(c) notice of any increase, reduction or rearrangement of Company's obligations under any Agreement or notice of any extension of time for the payment of any sums due and payable to the Counterparty under any Agreement;

(d) except as expressly set forth herein, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest or any other notice of any other kind with respect to the Guaranteed Obligations; and

(e) except as expressly set forth herein, any requirement that suit be brought against, or any other action by the Counterparty be taken against, or any notice of default or other notice be given to, or any demand by made on, Company or any other person, or that any other action be taken or not taken as a condition to the Guarantor's liability for the Guaranteed Obligations under this Guaranty or as a condition to the enforcement of this Guaranty against the Guarantor.

4. **Subrogation.** The Guarantor shall be subrogated to all rights of the Counterparty against Company in respect of any amounts paid by the Guarantor pursuant to the Guaranty, provided that the Guarantor waives any rights it may acquire by way of subrogation under this Guaranty, by any payment made hereunder or otherwise (including, without limitation, any statutory rights of subrogation under Section 509 of the Bankruptcy Code, 11 U.S.C. § 509, or otherwise), reimbursement, exoneration, contribution, indemnification, or any right to participate in any claim or remedy of the Counterparty against Company or any collateral which the Counterparty now has or acquires, until all of the Guaranteed Obligations shall have been irrevocably paid to the Counterparty in full. If (a) the Guarantor shall perform and shall make payment to the Counterparty of all or any part of the Guaranteed Obligations and (b) all the Guaranteed Obligations shall have been paid in full, the Counterparty shall, at the Guarantor's request, execute and deliver to the Guarantor appropriate documents necessary to evidence the transfer by subrogation to the Guarantor of any interest in the Guaranteed Obligations resulting from such payment by the Guarantor.

5. **Notices.** All demands, notices and other communications provided for hereunder shall, unless otherwise specifically provided herein, (a) be in writing addressed to the party receiving the notice at the address set forth below or at such other address as may be designated by written notice, from time to time, to the other party, and (b) be effective upon delivery, when mailed by U.S. mail, registered or certified, return receipt requested, postage prepaid, or personally delivered. Notices shall be sent to the following addresses:

If to Counterparty:

East Ohio Gas Company
Attn: Clifford E. Andrews
1201 E. 55th Street
Cleveland, Ohio 44103

Exhibit C-4 "Financial Arrangements", continued (Guaranty Agreement, p.4)

If to Guarantor:

Chesapeake Utilities Corporation
909 Silver Lake Boulevard
Dover, Delaware 19904
Attn: Beth W. Cooper
Senior Vice President and CFO

6. **Demand and Payment.** Counterparty is not entitled to make demand upon Guarantor until a default occurs in payment of any Guaranteed Obligations by Company to Counterparty. Any demand by the Counterparty for payment hereunder shall be in writing, reference this Guaranty, reference the Guaranteed Obligations, and signed by a duly authorized representative of the Counterparty and delivered to the Guarantor pursuant to Section 5 hereof. There are no other requirements of notice, presentment or demand. The Guarantor shall pay, or cause to be paid, such Guaranteed Obligations within twenty (20) business days of receipt of such demand.

7. **No Waiver; Remedies.** Except as to applicable statutes of limitation, no failure on the part of Counterparty to exercise, and no delay in exercising, any right hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

8. **Term; Termination.** This Guaranty shall continue in full force and effect from the Effective Date until the earlier of (a) the 364th day following the Effective Date or (b) thirty (30) days following Guarantor's notice, in writing, to Counterparty of Guarantor's termination of this Guaranty (the "Termination Date"); provided, however, the termination of this Guaranty shall not affect Guarantor's obligations hereunder with respect to any transaction entered into prior to such Termination Date, and this Guaranty shall remain in full force and effect until all Guaranteed Obligations arising with respect to such transactions have been fully satisfied..

9. **Assignment; Successors and Assigns.** The Guarantor and the Counterparty shall not assign its rights hereunder without the prior written consent of the other party, and any assignment without such prior written consent shall be null and void and of no force or effect. This Guaranty shall be binding upon and inure to the benefit of the each party hereto and their respective successors and permitted assigns.

10. **Amendments, Etc.** Subject to the Guarantor's right to terminate this Guaranty pursuant to Paragraph 8, no amendment of this Guaranty shall be effective unless in writing and signed by Guarantor and Counterparty. No waiver of any provision of this Guaranty nor consent to any departure by the Guarantor therefrom shall in any event be effective unless such waiver shall be in writing and signed by Counterparty. Any such waiver shall be effective only in the specific instance and for the specific purpose for which it was given.

Exhibit C-4 "Financial Arrangements", continued (Guaranty Agreement, p.5)

11. **Caption.** The captions in this Guaranty have been inserted for convenience only and shall be given no substantive meaning or significance whatsoever in construing the terms and provisions of this Guaranty.

12. **Representation and Warranties.**

The Guarantor represents and warrants as follows:

(a) The Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets.

(c) This Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting creditor's rights and to general equity principles.

13. **GOVERNING LAW. THIS GUARANTY SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF DELAWARE WITHOUT REGARD OR REFERENCE TO THE CONFLICT OF LAWS PRINCIPLES OF ANY JURISDICTION.** However, if any provision of this Guaranty shall be prohibited by or invalid under such law, such provision shall be ineffective to the extent of such prohibition or invalidity without invalidating the remainder of such provision or the remaining provisions of this Guaranty.

14. **Entire Agreement.** This Guaranty constitutes the entire agreement and understanding between Guarantor and Counterparty with respect to the Guaranteed Obligations.

Exhibit C-4 "Financial Arrangements", continued (Guaranty Agreement, p.6)

IN WITNESS WHEREOF, the Guarantor has caused this Guaranty to be duly executed and delivered by its duly authorized representative effective as of this 1st day of June, 2015 ("Effective Date").

By: Beth W. Cooper
Name: Beth W. Cooper
Title: Senior Vice President and CFO

By: Thomas E. Mahn
Name: Thomas E. Mahn
Title: Treasurer

ATTEST:

By: _____
Secretary

Exhibit C-5 "Forecasted Financial Statements"

Peninsula Energy Services Company

FORECASTED INCOME STATEMENT (Ohio Retail Only)

Forecast for Years Ending December 31, 2020 (Year 1) and December 31, 2021 (Year 2)

	Year 1	Year 2
Operating Revenues	$ 13,935,100	$ 15,328,610
Operating Expenses		
Cost of sales	13,372,050	14,709,255
Operations	397,319	402,168
Depreciation and amortization	-	-
Total Operating Expenses	13,769,369	15,111,423
Operating Income (Loss)	165,731	217,187
Interest charges	45,891	47,267
Income Before Income Tax	119,841	169,920
Income Taxes	35,952	50,976
Net Income (Loss)	$ 83,889	$ 118,944

Assumptions for PESCO Ohio Forecasted Income Statement

- Assumed 2020 DEO and COH retail revenue would track closely to 2019 actuals, with a 10% increase in sales for 2021.
- Assumed prices and margins would maintain closely to July 2019 actual results.
- Assumed salaries & benefits would reflect 50% of a sales manager, 33% of a senior origination manager and 33% of a scheduler.
- Assumed additional costs for travel, vehicle expense and supplies based on headcount ratios above.
- Assumed an effective income tax rate of 30%.
- Assumed 11% of PESCO's charges for Corporate and Shared Services Charges and Interest Expense would be attributed to Ohio, based on 2019 forecasted gross margin.

Exhibit C-6 "Credit Rating"

Peninsula Energy Services Company, Inc. (PESCO) is a wholly owned subsidiary of Chesapeake Utilities Corporation (CUC), and CUC guarantees the obligations of PESCO. CUC has no publicly-issued debt – its debt is privately placed. Therefore, CUC is rated by the National Association of Insurance Commissioners (NAIC). CUC has a credit rating of NAIC 1 – the highest credit rating provided by this entity and equivalent to an "A" rating from Moody's and Standard and Poors. Per the NAIC website, NAIC 1 is assigned to obligations that exhibit the highest quality.

This rating indicates that credit risk is at its lowest and the issuer's credit profile is stable. Considering this profile, it is expected that interest and principal on the issuance will be paid in accordance with the contractual agreement and that repayment of principal is well protected.

Included in this submittal is an excerpt of a document (Exhibit B) prepared by the Securities Valuation Office of NAIC which compares NAIC-prepared ratings to those of other rating agencies. More information can be found at www.naic.org/svo.htm.

NAIC CRP Rating Equivalents to SVO Designations

(A) Moody's	
Corporate, Government Counterparty and Municipal Ratings	**SVO**
Aaa; Aa 1, 2, 3; A 1, 2, 3,	1
Baa 1, 2, 3,	2
Ba 1, 2, 3,	3
B 1, 2, 3,	4
Caa, 1, 2, 3	5
Ca, C	6
Commercial Paper and Short Term Counterparty Ratings	
P-1	1
P-2	2
P-3	3
N-P (Not prime)	6
Preferred Stock	
Aaa; Aa 1, 2, 3; A 1, 2, 3,	1
Baa 1, 2, 3,	2
Ba 1, 2, 3,	3
B 1, 2, 3,	4
Caa	5
Ca, C	6
(B) Standard and Poor's	
Corporate Counterparty and Municipal Ratings — Public Bonds	
AAA, AA+, AA, AA-, A+, A, A-	1
BBB+, BBB, BBB-	2
BB+, BB, BB-	3
B+, B, B-	4
CCC+, CCC, CCC-	5
CC, C, D	6
Commercial Paper	
A, A-1	1
A-2	2
A-3	2
B	4
C	5
D	6
Preferred Stock	**SVO**
AAA, AA+, AA, AA-, A+, A, A-	1
BBB+, BBB, BBB-	2
BB+, BB, BB-	3
B+, B, B-	4
CCC	5
CC, C, D	6
(C) Fitch	
Fixed Income and Counterparty Ratings	
AAApre	1*

Exhibit C-7 "Credit Report"

N/A

Exhibit C-8 "Bankruptcy Information"

There have been no such declarations of bankruptcy or filings of reorganization protection from creditors made by PESCO, its affiliates, or its parent company or any officers of the applicant.

Exhibit C-9 "Merger Information"

There have been no dissolutions, mergers, or acquisitions involving PESCO within the most recent two years preceding this application for renewal.

Exhibit C-10 "Corporate Structure"

PESCO is an unregulated subsidiary of Chesapeake Utilities Corporation, a diversified energy company focused on the distribution and transmission of natural gas, electricity, and propane throughout several states in the Northeast, Midwest, and Southeast. Through regulated and unregulated subsidiaries, Chesapeake's family of companies strives to provide operational excellence and exceptional service to the customers we serve and in the communities where its businesses operate.

Regulated entities:

Pipelines: *Eastern Shore Natural Gas* owns and operates a 486-mile interstate natural gas pipeline that transports 50 Bcf of natural gas annually from four pipeline interconnects in Pennsylvania to customers in the Delmarva Peninsula. *Peninsula Pipeline* owns and operates an intra-state natural gas pipeline in Florida providing transportation services linking supply to other pipeline interconnects, local distribution systems, industrial customers and power generation facilities in the state.

Distribution: *Chesapeake Utilities* natural gas distribution system serves approximately 68,000 residential, commercial, and industrial customers operating approximately 1,400 miles of gas distribution mains in Delaware and Maryland. *Florida Public Utilities* owns and operates roughly 2,900 miles of natural gas distribution mains across 21 counties in Florida serving 80,000 natural gas, 32,000 electricity, and 17,000 propane customers throughout Florida. *Sandpiper Energy* serves approximately 11,000 residential, commercial, and industrial customers in Worcester County, MD. Originally a propane distribution system, Sandpiper also owns and operates over 300 miles of natural gas distribution mains and is actively converting its customers to natural gas.

Unregulated entities:

Peninsula Energy Services Company (PESCO) provides natural gas supply, asset management, and risk management services to retail and whole customers in the Mid-Atlantic, Southeast, and Appalachian Basin. PESCO transacts on more than 10 transmission pipelines and over 16 local distribution companies in six states.

Aspire Energy owns and operates over 2,700 miles of pipelines systems in 40 counties throughout Ohio. Aspire's natural gas infrastructure provides natural gas supplies to several local distribution companies and cooperatives, sourcing gas from approximately 300 local producers. The company provides additional services to maintain quality and reliability to wholesale markets.

Sharp Energy distributes propane to 42,000 customers in Delaware, Maryland, Virginia, and southeastern Pennsylvania. *Sharp AutoGas* fuels over 1,200 vehicles and is available to 48 propane fueling stations in Delaware, Maryland, Virginia, Pennsylvania, and Florida.

Exhibit D-1 "Operations"

PESCO's natural gas supply business is highly operational and is staffed with the operational expertise to assure complete compliance and operational integrity to fulfill our role as a retail natural gas supplier. In the pursuit of business, PESCO's operations and optimization teams secure long and short term firm pipeline capacity and supply to LDC city gates on the many pipelines where we do business. Decisions to purchase primary firm, secondary firm, and released capacity and on what pipelines and in which markets are based on current and projected customer growth plans and the company's pre-established risk tolerances. As a risk prevention policy, all transactions for the purchase and sale of natural gas and related assets are memorialized in signed contracts with each counterparty.

PESCO's nominations team schedules all receipt and delivery supply for the company internally and does so for each pipeline, LDC, producer, and customer with whom we do business. In addition to daily scheduling to meet the needs of our customers and balancing requirements of our pools, the operations and optimization teams work cohesively to balance behind each LDC and for each customer pool and stand-alone customer bank. Not only is this a vital operational necessity of our business, it is a daily cost mitigation effort to assure financial viability of our company. PESCO's operations team, in concert with its optimization and originations teams, work closely with utilities and pipelines to perform as expected of a highly-respected natural gas supplier. Part of a larger diversified family of pipelines, utilities, and energy distribution companies, PESCO has decades of experience and understands the necessity to perform all operational activities required to fulfill our obligations to supply natural gas to each natural gas city gate for our customer base.

Exhibit D-2 "Operations Expertise"

PESCO's Scheduling Manager has over 23 years of experience in the natural gas industry and oversees a team of seasoned operational personnel whose primary focus is balancing PESCO's supply to meet our pipeline delivery and balancing obligations. Scheduling is based on meeting customer demand and contractual obligations, including balancing storage, banks, supply pools, and daily pipeline flows to meet the operational requirements behind each LDC where we operate. Operationally, Ohio's accounts are monitored daily by two dedicated schedulers with several additional operational personnel available as back-up to manage gas nominations and gas flows adjusting accordingly to meet demand and operational constraints.

Our team of schedulers has been successfully performing these same operational functions for every pipeline and utility behind which we have continuously operated for years. The operations teams' expertise has assured no operational or performance issues or failures to deliver all the gas required to meet our supply and balancing obligations to our customers, pipelines, and LDCs across many states, including within the Ohio market.

Exhibit D-3 "Key Technical Personnel"

Al Gallo, Assistant Vice President (agallo@pescoenergy.com / PH: 302-736-7621)

Al is Assistant Vice President of the business unit has been working in commodity markets for 20 years and in energy markets for 15 years. Due to this experience, we are prepared to deal with operational challenges and market volatility.

Marissa Stipa, Director, Optimization (mstipa@pescoenergy.com / PH: 302-213-7518)

Marissa is Director, Optimization which includes management oversight of all PESCO's Operational functions and scheduling staff. She has over 23 years of Operational experience on many pipeline and utility systems and oversees daily activity of all scheduling and balancing for the company. Marissa's responsibilities include the essential acquisition of and planning for operational assets and supply to serve PESCO's forward book.

Gary Dean, Sr. Manager, Optimization (gdean@pescoenergy.com / PH: 302-270-3248)

Gary is the Senior Manager, Optimization for PESCO and is responsible for all pricing and tariff-related matters. He also manages the hedging of the company's forward book. He has 30 years energy industry experience ranging from operations and construction to regulatory and rate matters.

Rachel Beringer, Supply & Transportation Manager (rberinger@pescoenergy.com / PH: 302-272-8753)

Rachel is one of several Managers of Supply and Transportation for PESCO. She is responsible for trading, scheduling, and balancing all gas needs for the entire Appalachian Basin region and schedules supplies for PESCO's Ohio customers on related pipelines and LDCs. She has 12 years' experience in the energy industry ranging from natural gas scheduling and trading to risk management.

Evan Kuzmenski, Supply & Transportation Manager (ekuzmenski@pescoenergy.com / PH: 302-382-3160)

Evan is one of PESCO's Supply and Transportation Managers whose operational focus is on trading, scheduling, and balancing in the Appalachian Basin. Evan is responsible for operational activities in Ohio and Western Pennsylvania, managing supplies, balancing, and scheduling behind pipelines and utilities. His has 5 years' operational experience from an energy trading firm and a local producer.

Martha Audet, Reconciliation Analyst (maudet@pescoenergy.com / PH: 302-858-8943)

Martha's role as Reconciliation Analyst is overseeing PESCO's enrollment process and validating all customer LDC enrollments, verifying accuracy of account data, and analyzing usage and billing figures. Martha brought to PESCO many years of energy accounting experience within Chesapeake Utilities and she has oversight of all usage and commission reporting. Martha analyzes all utility enrollment reporting and is critical to building our customer and utility counterpart relationships.

Gwen Kyle, Manager of Origination, Midwest (gkyle@pescoenergy.com / PH: 302-242-9793)

Gwen is Manager of Origination, Midwest covering the state of Ohio and adjacent states. With more than 25 years in the industry, she began her career with a regulated utility where she worked for more than a decade holding key Gas Transportation roles during the height of deregulation. Gwen has focused her expertise as a natural gas supplier and a consultant the past 15 years and her extensive experience in Ohio includes tariff interpretation and utility GTS and Choice program compliance.

Total PESCO

Comparative Balance Sheet -- Quarterly Audit

December 31, 2018

Case No.: 17-1916-GA-CRS

Peninsula Energy Services Company, Inc.

Exhibit C-3 "Financial Statements"

	Cur Yr 12/31/18	Prev Qtr 09/30/18	Increase (Decrease)	% Change	Prior YE 12/31/17	Increase (Decrease)	% Change
Assets							
Property, Plant and Equipment							
Plant in service	$1,242,057	$1,198,666	$43,391	3.62%	$1,123,661	$118,396	10.54%
Less: Accumulated depreciation & amortization	(206,196)	(161,533)	(44,663)	(27.65%)	(36,681)	(169,516)	(462.14%)
Plus: Construction work in progress	0	0	0	0.00%	3,257	(3,257)	(100.00%)
Net property, plant and equipment	1,035,860	1,037,133	(1,272)	(0.12%)	1,090,237	(54,377)	(4.99%)
Current Assets							
Cash and cash equivalents	1,952,218	1,467,268	484,950	33.05%	982,123	970,096	98.78%
Trade receivables	31,073,679	17,407,691	13,665,988	78.51%	27,023,754	4,049,925	14.99%
Other receivables	493,694	756,075	(262,381)	(34.70%)	1,526,712	(1,033,018)	(67.66%)
Accrued revenue - Margin only	2,743,165	1,235,900	1,507,265	121.96%	645,514	2,097,651	324.96%
Accrued revenue - Fuel costs only	2,115,829	1,010,517	1,105,312	109.38%	1,374,858	740,971	53.89%
Inter-company receivable (payable)	(10,525,683)	(8,093,637)	(2,432,046)	(30.05%)	(7,987,421)	(2,538,263)	(31.78%)
Storage gas prepayments	3,170,162	3,137,583	32,580	1.04%	2,305,427	864,735	37.51%
Prepaid expenses	439,475	672,083	(232,608)	(34.61%)	1,461,136	(1,021,661)	(69.92%)
Derivative assets, at fair value	13,082,912	9,955,304	3,127,608	31.42%	92,159	12,990,753	14,096.06%
Other current assets	2,812,739	2,064,751	747,988	36.23%	6,302,848	(3,490,109)	(55.37%)
Total current assets	47,358,191	29,613,535	17,744,656	59.92%	33,727,111	13,631,080	40.42%
Deferred Charges and Other Assets							
Goodwill	4,269,362	4,269,362	0	0.00%	6,769,362	(2,500,000)	(36.93%)
Other intangible assets, net	2,357,274	2,462,824	(105,550)	(4.29%)	2,779,472	(422,198)	(15.19%)
Total deferred charges and other assets	6,626,636	6,732,185	(105,550)	(1.57%)	9,548,834	(2,922,198)	(30.60%)
Total Assets	**$55,020,687**	**$37,382,854**	**$17,637,834**	**47.18%**	**$44,366,182**	**$10,654,505**	**24.01%**
Working Capital (AR+Inv-AP)	*4,809,182*	*2,867,109*	*1,942,073*	*67.74%*	*6,243,946*	*(1,434,764)*	*(22.98%)*
AR incl. allowance for uncollectible accounts of:	*(49,600)*	*(45,300)*	*(4,300)*	*(9.49%)*	*(60,000)*	*10,400*	*17.33%*

Total PESCO

Comparative Balance Sheet -- Quarterly Audit

December 31, 2018

	Cur Yr 12/31/18	Prev Qtr 09/30/18	Increase (Decrease)	% Change	Prior YE 12/31/17	Increase (Decrease)	% Change
Capitalization and Liabilities							
Capitalization							
Stockholders equity							
Additional paid-in capital	$1,681,885	$1,681,885	$0	0.00%	$1,600,000	$81,885	5.12%
Retained earnings	4,296,442	4,638,139	(341,697)	(7.37%)	5,548,390	(1,251,948)	(22.56%)
Accumulated other comprehensive income (loss)	216,652	(74,290)	290,942	391.63%	(232,175)	448,827	193.31%
Treasury stock	71,288	71,288	0	0.00%	0	71,288	0.00%
Total stockholders' equity	6,266,267	6,317,022	(50,755)	(0.80%)	6,916,215	(649,948)	(9.40%)
Total capitalization	6,266,267	6,317,022	(50,755)	(0.80%)	6,916,215	(649,948)	(9.40%)
Current Liabilities							
Accounts payable	31,123,491	16,786,998	14,336,493	85.40%	22,800,180	8,323,311	36.51%
Customer deposits and refunds	1,535,316	1,517,317	17,998	1.19%	1,977,642	(442,326)	(22.37%)
Income taxes payable (receivable)	226,724	765,234	(538,510)	(70.37%)	2,121,707	(1,894,983)	(89.31%)
Accrued compensation	332,235	230,496	101,739	44.14%	265,263	66,972	25.25%
Derivative liabilities, at fair value	13,266,911	9,769,752	3,497,159	35.80%	6,245,001	7,021,910	112.44%
Other accrued liabilities	2,746,202	3,157,948	(411,746)	(13.04%)	3,333,715	(587,513)	(17.62%)
Total current liabilities	49,230,878	32,227,746	17,003,133	52.76%	36,743,508	12,487,371	33.99%
Deferred Credits and Other Liabilities							
Deferred income taxes	(705,150)	(1,390,472)	685,322	49.29%	(1,793,540)	1,088,390	60.68%
Other pension and benefit costs	228,692	228,558	134	0.06%	0	228,692	0.00%
Other liabilities	0	0	0	0.00%	2,500,000	(2,500,000)	(100.00%)
Total deferred credits and other liabilities	(476,458)	(1,161,914)	685,456	58.99%	706,460	(1,182,918)	(167.44%)
Total Capitalization and Liabilities	**$55,020,687**	**$37,382,854**	**$17,637,834**	**47.18%**	**$44,366,182**	**$10,654,505**	**24.01%**

Total PESCO
Comparative Balance Sheet – Quarterly Audit
December 31, 2017

Case No.: 17-1916-GA-CRS
Peninsula Energy Services Company, Inc.
Exhibit C-3 "Financial Statements"

	Cur Yr 12/31/17	Prev Qtr 09/30/17	Increase (Decrease)	% Change	Prior YE 12/31/16	Increase (Decrease)	% Change
Report out of Balance	*$0*	*$0*	*$0*	*(100.00%)*	*$0*	*$0*	*0.00%*
Assets							
Property, Plant and Equipment							
Plant in service	1,123,661	924,961	198,700	21.48%	0	1,123,661	0.00%
Less: Accumulated depreciation & amortization	(36,681)	(3,173)	(33,508)	(1,055.91%)	0	(36,681)	0.00%
Plus: Construction work in progress	3,257	24,274	(21,017)	(86.58%)	0	3,257	0.00%
Net property, plant and equipment	1,090,237	946,062	144,176	15.24%	0	1,090,237	0.00%
Current Assets							
Cash and cash equivalents	982,123	949,711	32,412	3.41%	(295,092)	1,277,214	432.82%
Accounts receivable	28,550,466	17,744,700	10,805,766	60.90%	18,842,950	9,707,516	51.52%
Accrued revenue - Margin only	645,514	3,068,339	(2,422,825)	(78.96%)	40,059	605,455	1,511.40%
Accrued revenue - Fuel costs only	1,374,858	1,239,783	135,076	10.90%	703,187	671,671	95.52%
Inter-company receivable (payable)	(7,987,421)	(5,948,258)	(2,039,163)	(34.28%)	2,445,946	(10,433,367)	(426.56%)
Storage gas prepayments	2,305,427	3,035,415	(729,988)	(24.05%)	2,769,572	(464,144)	(16.76%)
Prepaid expenses	1,461,136	2,495,922	(1,034,786)	(41.46%)	131,297	1,329,839	1,012.85%
Derivative assets, at fair value	92,159	1,214	90,945	7,493.27%	112,955	(20,796)	(18.41%)
Other current assets	6,302,848	4,254,728	2,048,121	48.14%	1,678,862	4,623,987	275.42%
Total current assets	33,727,111	26,841,553	6,885,558	25.65%	26,429,736	7,297,375	27.61%
Deferred Charges and Other Assets							
Goodwill	6,769,362	6,709,362	60,000	0.89%	0	6,769,362	0.00%
Other intangible assets, net	2,779,472	2,885,022	(105,549)	(3.66%)	0	2,779,472	0.00%
Total deferred charges and other assets	9,548,834	9,594,383	(45,549)	(0.47%)	0	9,548,834	0.00%
Total Assets	**$44,366,182**	**$37,381,998**	**$6,984,184**	**18.68%**	**$26,429,736**	**$17,936,446**	**67.86%**
Working Capital (AR+Inv-AP)	*7,770,658*	*5,275,934*	*2,494,724*	*47.28%*	*7,844,849*	*(74,191)*	*(0.95%)*
AR incl. allowance for uncollectible accounts of:	*(60,000)*	*(35,007)*	*(24,993)*	*(71.39%)*	*(12,200)*	*(47,800)*	*(391.80%)*

Total PESCO
Comparative Balance Sheet – Quarterly Audit
December 31, 2017

	Cur Yr 12/31/17	Prev Qtr 09/30/17	Increase (Decrease)	% Change	Prior YE 12/31/16	Increase (Decrease)	% Change
Capitalization and Liabilities							
Capitalization							
Stockholders equity							
Additional paid-in capital	$1,600,000	$1,600,000	$0	0.00%	$1,600,000	$0	0.00%
Retained earnings	5,548,390	9,659,775	(4,111,386)	(42.56%)	8,967,569	(3,419,179)	(38.13%)
Accumulated other comprehensive income (loss)	(232,175)	(1,059,507)	827,332	78.09%	69,357	(301,532)	(434.75%)
Total stockholders' equity	6,916,215	10,200,268	(3,284,054)	(32.20%)	10,636,926	(3,720,711)	(34.98%)
Total capitalization	6,916,215	10,200,268	(3,284,054)	(32.20%)	10,636,926	(3,720,711)	(34.98%)
Current Liabilities							
Accounts payable	22,800,180	16,776,888	6,023,293	35.90%	11,741,347	11,058,834	94.19%
Customer deposits and refunds	1,977,642	1,799,380	178,262	9.91%	1,545,876	431,766	27.93%
Income taxes payable (receivable)	2,121,707	3,043,059	(921,352)	(30.28%)	1,364,930	756,777	55.44%
Accrued compensation	265,263	181,956	83,307	45.78%	127,842	137,421	107.49%
Derivative liabilities, at fair value	6,245,001	1,732,197	4,512,804	260.52%	772,935	5,472,066	707.96%
Other accrued liabilities	3,333,715	2,956,445	377,270	12.76%	518,904	2,814,810	542.45%
Total current liabilities	36,743,508	26,489,924	10,253,584	38.71%	16,071,834	20,671,673	128.62%
Deferred Credits and Other Liabilities							
Deferred income taxes	(1,793,540)	(1,808,194)	14,654	0.81%	(279,024)	(1,514,516)	(542.79%)
Other liabilities	2,500,000	2,500,000	0	0.00%	0	2,500,000	0.00%
Total deferred credits and other liabilities	706,460	691,806	14,654	2.12%	(279,024)	985,484	353.19%
Total Capitalization and Liabilities	**$44,366,182**	**$37,381,998**	**$6,984,184**	**18.68%**	**$26,429,736**	**$17,936,446**	**67.86%**

Natural Gas Marketing (PESCO)
12-Month Rolling Income Statement
December 31, 2018

Case No.: 17-1916-GA-CRS
Peninsula Energy Services Company, Inc.
Exhibit C-3 "Financial Statements"

	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	Total
Statement of Income													
Revenue	$34,487,593.64	$27,247,107.72	$19,824,193.20	$17,916,915.55	$15,037,832.87	$15,840,975.55	$17,841,982.43	$16,736,023.84	$17,040,999.09	$16,961,379.64	$24,802,446.00	$34,973,171.55	$256,712,820.68
Cost of Sales	37,069,337.50	23,452,862.98	19,861,313.05	17,405,734.84	14,566,548.64	14,230,594.51	18,015,564.81	16,740,192.32	16,132,067.76	16,616,407.62	23,188,588.10	34,843,115.37	252,111,425.80
Gross Margin	(2,581,743.86)	3,794,244.74	(37,119.85)	513,180.71	452,283.63	1,610,281.04	(173,582.38)	(4,168.48)	908,931.33	344,972.02	1,613,859.90	130,056.18	6,601,196.08
Operating Expenses													
Business Unit													
Payroll & benefits	228,695.33	237,675.45	281,095.90	225,828.02	248,995.40	251,704.93	217,218.27	254,410.19	221,742.89	333,560.35	268,903.20	271,473.56	3,041,303.52
Other business unit expenses	117,621.47	174,794.81	238,103.41	135,292.80	153,401.29	270,230.97	42,753.01	332,347.70	245,665.73	221,020.75	191,881.48	444,767.54	2,597,880.76
Depreciation, ARC & Amort.	48,560.09	48,560.10	48,560.11	48,560.06	48,560.10	48,560.09	48,510.80	48,510.82	48,510.82	48,510.79	48,510.91	48,510.81	582,425.50
Other taxes	23,936.15	21,955.07	77,938.50	21,741.38	27,388.45	16,056.21	9,634.95	16,689.57	20,508.86	33,386.77	15,379.76	31,981.36	316,607.03
Corporate Services	69,630.78	57,531.36	76,194.28	62,919.95	65,868.83	60,231.34	72,747.71	55,943.90	88,466.10	63,203.99	65,693.99	83,166.51	795,618.66
Corporate Overhead	62,476.95	58,737.45	67,997.59	76,334.22	69,830.74	62,902.43	59,568.43	47,425.23	46,842.34	41,044.99	45,984.55	51,968.42	684,913.34
Total Operating Expenses	551,120.77	599,254.24	788,889.79	584,476.23	643,862.81	709,686.97	450,433.17	755,327.41	669,736.74	740,727.81	636,353.89	911,868.20	8,021,748.83
Operating Income Before Transaction/Transition Costs	**(3,132,864.73)**	**3,194,990.50**	**(826,009.64)**	**(51,295.52)**	**(191,578.98)**	**900,585.07**	**(624,015.55)**	**(759,495.89)**	**239,192.59**	**(395,755.59)**	**977,506.01**	**(781,812.02)**	**(1,420,553.75)**
Operating Income	**(3,132,864.73)**	**3,194,990.50**	**(826,009.64)**	**(51,295.52)**	**(191,578.98)**	**900,585.07**	**(624,015.55)**	**(759,495.89)**	**239,192.59**	**(395,755.59)**	**977,506.01**	**(781,812.02)**	**(1,420,553.75)**
Total other income (expense)	(1,458.11)	(248.32)	(31,534.89)	(11.70)	(146.61)	4,029.15	(903.41)	(5,182.32)	(759.06)	112.56	(5,019.94)	31,115.26	(10,025.39)
Income (Loss) Before Interest Charges	(3,134,322.84)	3,194,744.18	(857,544.53)	(51,307.22)	(191,725.59)	904,614.22	(624,918.96)	(764,688.21)	238,423.53	(395,643.03)	972,486.07	(750,696.76)	(1,430,579.14)
Total interest charges	20,216.18	19,366.22	20,496.84	25,452.23	25,421.75	27,136.62	23,550.15	25,714.22	24,197.77	23,036.11	23,400.78	26,916.80	284,907.67
Income (Loss) Before Income Taxes	(3,154,539.02)	3,175,377.96	(878,041.37)	(76,759.45)	(187,147.34)	877,475.60	(648,469.11)	(790,402.43)	214,225.76	(418,679.14)	949,085.29	(777,613.56)	(1,715,486.81)
Income Taxes													
Operating (excl ESOP deduction)	(800,172.00)	857,815.00	(253,909.00)	(18,607.00)	(46,321.00)	228,884.00	(169,507.00)	(198,455.00)	(124,634.00)	(104,544.00)	239,955.00	(48,119.00)	(437,513.00)
Non-Operating (excl ITC)	(343.00)	9.00	(106.00)	(37.00)	(37.00)	3,363.00	(257.00)	25.00	(196.00)	25.00	(1,266.00)	8,439.00	9,618.00
Total Income Taxes	(800,515.00)	857,824.00	(254,015.00)	(18,644.00)	(46,358.00)	232,247.00	(169,764.00)	(198,430.00)	(124,830.00)	(104,519.00)	238,689.00	(39,680.00)	(427,895.00)
Net Income from Continuing Operations	**(2,354,024.02)**	**2,317,553.96**	**(624,026.37)**	**(58,115.45)**	**(140,789.34)**	**645,128.60**	**(478,705.11)**	**(591,972.43)**	**339,055.76**	**(314,160.14)**	**710,396.29**	**(737,933.56)**	**(1,287,591.81)**
Net Income	**(2,354,024.02)**	**2,317,553.96**	**(624,026.37)**	**(58,115.45)**	**(140,789.34)**	**645,128.60**	**(478,705.11)**	**(591,972.43)**	**339,055.76**	**(314,160.14)**	**710,396.29**	**(737,933.56)**	**(1,287,591.81)**

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12-Month Rolling P&L
Natural Gas Marketing (PESCO)
12-Month Rolling Income Statement
December 31, 2018

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	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	Total
Operating Expense Summary													
Business Unit Direct													
Payroll													
Salaries	$170,337.38	$170,321.62	$177,327.41	$167,944.87	$183,368.58	$185,949.90	$193,143.70	$203,904.81	$170,479.66	$226,866.53	$189,289.37	$204,903.17	$2,243,856.52
OT, On Call & Comp Time	0.00	0.00	177.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	177.47
Bonus/Incentive Pay	18,965.00	25,771.00	7,982.00	22,366.00	22,367.00	22,368.00	(61,795.00)	10,345.00	11,393.00	11,162.00	10,772.00	54,762.00	156,460.00
Short-term Cash Bonus	5,747.00	5,747.00	64,973.00	3,460.00	3,460.00	235.00	13,506.00	(364.00)	(364.00)	(742.00)	6,508.00	(37,407.00)	66,759.00
Long-term Cash Bonus	7,184.00	7,184.00	829.00	4,485.00	4,489.00	3,034.00	25,300.00	6,215.00	6,215.00	13,100.00	13,102.00	(24,730.00)	66,410.00
Signing Bonus	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19,000.00	0.00	10,000.00	29,000.00
Other Bonuses	0.00	0.00	0.00	0.00	0.00	10,000.00	0.00	0.00	0.00	0.00	0.00	3,000.00	13,000.00
Temp services	0.00	0.00	0.00	0.00	48.64	47.20	48.64	1,647.30	2,493.31	0.00	12.48	0.00	4,297.57
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15,000.00	21,923.00	36,923.00
Total Payroll	202,233.38	209,023.82	251,288.88	198,260.87	213,733.22	221,634.10	170,203.34	221,748.11	190,216.99	269,406.53	234,683.85	232,451.17	2,618,886.56
Benefits													
Claims-Health & Dental	13,774.00	15,007.00	15,735.00	14,842.00	21,873.00	18,813.00	17,837.00	17,400.26	16,380.56	19,967.64	19,201.42	18,685.99	207,517.08
Employee withholding	(5,243.56)	(5,365.72)	(5,330.72)	(4,961.38)	(5,265.51)	(4,852.67)	(5,214.23)	(5,180.47)	(4,407.66)	(5,725.48)	(5,486.60)	(5,310.96)	(62,344.94)
Admin fees, workers comp & other	3,545.61	3,976.49	6,150.75	3,623.74	4,978.75	3,570.84	2,980.55	4,516.32	6,171.95	4,870.90	3,956.65	4,458.01	53,102.57
401K	14,285.90	14,823.91	13,251.59	13,852.79	13,557.94	13,925.33	12,661.61	15,925.95	13,065.00	11,643.88	14,546.05	21,017.45	172,559.60
Other benefits	0.00	209.96	0.00	0.00	118.00	614.33	18,750.00	0.00	318.05	33,394.99	7.82	171.90	53,582.64
Total Benefits	26,561.95	28,851.63	29,807.02	27,357.15	35,262.18	30,070.83	47,014.93	32,662.06	31,525.90	64,151.55	32,219.35	39,022.39	424,416.96
Departmental Expenses													
Travel, meals & training	14,306.69	18,791.08	38,639.63	15,549.87	14,328.19	9,796.12	25,993.78	11,172.06	7,814.79	43,796.10	10,489.97	7,013.66	215,671.94
Cell phones	2,001.24	1,819.20	2,021.47	3,204.26	2,827.82	2,002.64	2,663.33	2,182.11	2,929.28	2,845.01	2,360.35	2,196.28	29,056.00
Other	3,707.67	21,417.45	52,184.18	20,160.18	21,809.86	15,099.66	20,172.60	26,505.26	25,546.98	13,660.97	14,540.91	21,015.71	257,821.44
Total Departmental Expenses	20,015.60	40,027.73	92,845.28	38,914.31	38,965.87	26,898.41	48,829.71	41,859.45	36,291.06	60,306.08	27,371.23	30,225.65	502,549.38
Vehicle Expenses													
Fuel	2,612.52	1,331.06	1,421.59	1,501.08	1,631.84	1,595.93	1,532.23	1,617.86	1,954.17	2,325.86	3,030.27	1,350.52	21,904.93
Depreciation	3,213.59	5,764.61	4,489.15	4,489.14	4,489.17	4,489.15	5,790.23	5,476.66	5,808.24	5,808.19	5,808.25	6,531.39	63,157.87
Insurance	567.33	847.33	847.33	847.33	847.33	847.33	(1,152.57)	847.33	847.33	923.21	888.36	888.36	8,145.90
Other	157.44	204.78	249.31	146.42	532.52	92.82	1,332.70	131.59	1,176.98	217.87	4,350.59	2,304.72	10,897.74
Total Vehicle Expenses	6,550.98	8,147.78	7,007.36	6,983.97	7,500.86	7,025.23	7,502.49	9,073.44	9,786.72	9,275.13	14,077.47	11,074.99	104,106.44
Facilities & Operating Systems													
Rent & Leases	9,951.49	9,933.96	9,933.96	9,933.96	7,295.01	12,572.93	13,712.34	3,773.67	10,073.82	12,744.91	7,402.73	13,072.27	129,401.05
Utilities	597.48	800.89	842.46	1,469.07	945.14	3,218.76	2,607.65	1,387.76	440.17	1,387.94	929.32	693.67	15,330.35
Other operating expenses	3,866.06	473.42	611.88	1,538.80	2,428.36	2,996.79	5,790.12	3,753.72	4,600.63	2,933.96	3,130.76	7,048.78	38,975.30
Maintenance	35,848.30	29,563.05	48,123.05	123.05	7,051.89	4,486.69	4,363.64	13,817.46	59,213.23	38,013.23	38,013.23	39,013.23	326,629.85
Total Facilities & Op Sys Exp	50,265.35	40,771.32	59,511.37	13,164.88	17,720.20	22,975.17	26,473.75	22,732.63	84,327.85	56,080.04	50,476.04	59,827.95	504,336.55
Outside Services													
Legal	450.00	0.00	3,014.50	1,787.50	0.00	0.00	0.00	0.00	0.00	480.75	13,044.25	4,865.48	23,651.48
Consulting	19,500.00	65,251.86	94,668.95	59,746.68	97,571.74	179,874.04	(77,372.64)	242,750.03	105,035.49	83,720.42	64,896.16	123,554.95	1,038,997.68
Total Outside Services	19,950.00	65,251.86	97,683.45	61,534.18	97,571.74	179,874.04	(77,372.64)	242,750.03	105,035.49	84,201.17	77,740.41	128,420.43	1,062,649.16
Sales, Advertising & Communications													
Sales	400.00	0.00	425.00	525.00	2,716.98	0.00	238.80	(238.80)	0.00	85.00	3,569.63	0.00	7,822.61
Other	0.00	0.00	0.00	901.90	0.00	30.60	6.60	4,024.27	4,012.37	4,002.17	4,365.77	4,003.87	21,347.75
Total Sales, Advertising & Communications	400.00	0.00	425.00	1,526.90	2,716.98	30.60	245.40	3,785.47	4,012.37	4,087.17	7,935.40	4,003.87	29,170.36
Credit, Collections & Customer Service													
Bad Debts	4,676.04	6,197.85	(30,526.50)	5,963.67	5,163.65	22,920.35	4,788.51	4,595.84	7,979.97	4,369.46	5,483.76	(3,882.00)	37,768.91
Collection agencies & credit reports	602.00	5,275.39	0.00	39.38	13,388.00	0.00	5,742.00	0.00	10,424.00	6,404.00	0.00	4,682.00	46,754.77
Customer satisfaction & other	10,442.93	1,558.42	4,069.87	0.00	1,603.82	1,428.69	21,063.18	1,992.33	(17,494.12)	9,956.12	1,237.12	203,419.11	239,287.47
Total Credit, Collections & Customer Service	15,920.97	13,041.67	(26,456.63)	6,003.05	20,153.47	24,349.04	31,591.69	6,588.17	909.85	20,749.58	6,720.88	204,239.11	323,831.15
Bank/Merchant Fees	4,409.57	7,554.45	6,447.24	7,145.31	(1,227.83)	9,078.48	5,482.11	5,558.51	5,302.39	6,311.58	7,560.05	6,975.54	70,597.40
Miscellaneous													
Fees, Assessments & Discounts	0.00	0.00	640.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	640.32
Total Miscellaneous	0.00	0.00	640.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	640.32
Total BU Direct O&M	346,518.80	412,470.26	519,199.31	360,920.62	432,396.99	521,935.90	259,971.28	586,757.69	467,408.62	554,581.13	460,784.68	715,241.10	5,639,184.28
BU Taxes Other than Income	23,936.15	21,955.07	77,938.50	21,741.38	27,388.45	16,056.21	9,634.95	16,689.57	20,508.86	33,386.77	15,379.76	31,981.36	316,607.03
BU Depr, Amort & ARC	48,560.09	48,560.10	48,560.11	48,560.06	48,560.10	48,560.09	48,510.80	48,510.82	48,510.82	48,510.79	48,510.91	48,510.81	582,425.50

Total BU Direct Operating Exp.	419,013.04	452,965.43	645,697.92	431,222.06	508,345.24	586,562.20	318,117.03	651,958.28	536,428.30	636,476.59	524,675.35	798,739.27	6,538,218.51
Total Corporate Services	69,630.78	57,531.36	75,194.28	62,919.95	65,886.83	60,231.34	72,747.71	55,943.90	86,468.10	63,203.93	65,693.99	63,166.51	798,818.68
Total Corporate Overhead	62,476.95	58,737.45	67,997.59	70,334.22	69,630.74	62,902.43	59,568.43	47,425.23	46,842.34	41,044.99	45,984.55	51,968.42	684,913.34
Total Operating Expenses	551,120.77	569,254.24	788,889.79	564,476.23	643,862.81	709,695.97	450,433.17	755,327.41	669,738.74	740,727.51	636,353.89	911,868.20	8,021,748.83

ISDTL_12R_AUDDTL
12-Month Rolling P&L
Natural Gas Marketing (PESCO)
12-Month Rolling Income Statement
December 31, 2018

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	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	Total
Shared Services & Corporate Support													
Corporate Services													
Payroll	$28,364.44	$24,827.85	$31,574.74	$27,835.40	$30,344.49	$28,492.56	$30,106.14	$32,168.58	$27,218.64	$31,547.15	$30,280.15	$30,786.63	$353,766.75
Benefits	4,024.05	3,673.05	4,466.88	3,822.46	5,835.37	3,863.86	4,252.29	4,427.00	4,346.94	4,540.11	4,219.05	4,158.66	51,961.72
Department Expenses	6,821.24	1,378.95	2,213.35	4,043.39	4,057.87	1,558.72	4,491.88	(3,014.02)	1,915.31	2,884.55	8,498.32	2,225.08	35,074.82
Vehicle Expenses	34.98	11.49	11.56	11.22	14.43	10.03	14.32	13.82	14.55	14.32	14.37	13.11	178.20
Facilities & Operating Systems	19,299.41	17,892.01	25,840.45	17,078.04	15,170.92	12,251.47	15,477.32	12,585.66	27,860.73	12,508.60	11,883.97	12,014.40	199,622.98
Insurance	7,510.00	7,510.00	7,524.00	7,513.00	7,513.00	7,513.00	7,568.00	7,513.00	8,394.00	8,101.00	8,655.00	8,884.00	94,198.00
Outside Services	578.34	240.09	1,069.03	466.81	550.72	4,492.17	8,678.41	342.04	15,054.82	1,555.40	2,480.82	2,202.82	37,911.27
Subtotal - Corp. Svc. O&M	67,052.46	55,533.24	72,702.01	60,770.32	63,586.80	58,181.81	70,588.34	54,016.06	84,804.79	61,251.13	64,011.68	60,116.90	772,615.94
Taxes Other than Income	2,578.32	1,998.12	2,492.27	2,149.63	2,300.03	2,049.53	2,159.37	1,927.84	1,663.31	1,952.80	1,682.31	3,049.61	26,003.14
Total Corporate Services	69,630.78	57,531.36	75,194.28	62,919.95	65,886.83	60,231.34	72,747.71	55,943.90	86,468.10	63,203.93	65,693.99	63,166.51	798,618.68
Corporate Overhead													
Payroll	38,548.12	36,921.88	39,468.45	42,081.00	43,691.49	36,327.65	37,668.90	35,558.02	24,629.90	31,274.03	29,359.38	30,332.63	425,861.65
Benefits	4,042.89	4,114.72	7,065.05	4,034.68	5,935.83	4,788.71	6,947.84	5,260.79	4,662.61	2,496.96	3,850.75	3,845.68	57,066.51
Department Expenses	2,774.45	3,543.26	3,669.27	7,462.55	7,249.76	2,711.27	4,160.51	2,571.69	2,975.09	2,323.77	446.73	3,221.90	43,130.25
Vehicle Expenses	675.93	754.10	1,190.29	736.98	1,302.06	494.51	875.58	1,147.30	673.57	756.95	1,186.64	624.32	10,420.23
Facilities & Operating Systems	358.86	395.86	431.71	411.28	415.44	505.94	505.96	1,006.38	17.32	496.87	470.82	665.16	5,680.60
Insurance	32.91	31.09	37.01	32.99	36.55	46.31	37.78	42.14	44.74	50.43	44.45	50.15	496.55
Outside Services	7,786.88	6,156.52	4,842.25	6,779.31	5,353.14	12,345.50	2,140.54	(3,722.32)	8,145.61	6,851.46	5,112.54	6,448.82	68,217.45
Investor Relations	2,051.43	2,392.18	1,990.47	3,023.68	2,467.18	2,334.18	2,804.51	2,621.70	2,685.96	3,322.09	2,221.91	2,945.47	30,860.74
Sales, Advertising & Communications	141.86	582.37	(117.71)	2,811.22	218.09	352.50	261.07	521.40	656.47	1,101.06	1,244.79	1,606.65	9,381.97
Fees & Assessments	*3,655.44*	*1,741.74*	*4,217.08*	*1,589.28*	*1,540.93*	*1,729.92*	*2,807.15*	*1,165.12*	*1,248.95*	*(9,065.04)*	*976.24*	*1,910.55*	*12,517.36*
Subtotal - Corp OH O&M	60,048.77	56,632.72	62,813.87	68,964.97	68,210.47	61,836.47	58,229.84	46,171.22	45,735.42	39,818.58	44,918.25	50,751.73	663,733.31
Taxes Other than Income	2,428.18	2,104.73	5,183.72	1,369.25	1,420.27	1,265.96	1,338.59	1,254.01	1,103.92	1,426.41	1,066.30	1,216.69	21,180.03
Total Corporate Overhead	62,476.95	58,737.45	67,997.59	70,334.22	69,630.74	62,902.43	59,568.43	47,425.23	46,842.34	41,044.99	45,984.55	51,968.42	684,913.34

ISDTL_12R_AUDDTL
12-Month Rolling P&L
Natural Gas Marketing (PESCO)
12-Month Rolling Income Statement
December 31, 2018

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	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	Total
Other Support													
BU Depreciation, ARC & Amortization													
Depreciation	$13,376.92	$13,376.93	$13,376.94	$13,376.89	$13,376.93	$13,376.92	$13,327.63	$13,327.65	$13,327.65	$13,327.62	$13,327.74	$13,327.64	$160,227.46
Amortization	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	35,183.17	422,198.04
Total BU Depr., ARC & Amort.	48,560.09	48,560.10	48,560.11	48,560.06	48,560.10	48,560.09	48,510.80	48,510.82	48,510.82	48,510.79	48,510.91	48,510.81	582,425.50
BU Taxes Other than Income													
Payroll	17,950.53	14,827.84	23,814.85	13,404.92	14,628.88	15,156.62	8,187.47	12,909.90	9,500.73	15,153.31	10,859.68	17,890.54	174,235.27
Property	0.00	0.00	1,953.17	0.00	0.00	6,350.82	0.00	0.00	8,377.27	0.00	0.00	2,832.95	21,514.24
Revenue Related	0.00	0.00	0.00	0.00	0.00	2,785.20	0.00	0.00	0.00	0.00	0.00	0.00	2,785.20
Miscellaneous	5,985.62	7,127.23	52,170.48	8,336.46	12,759.57	(10,226.43)	1,467.48	3,779.67	2,530.86	18,233.46	4,520.06	11,287.84	118,072.32
Total BU Other Taxes	23,936.15	21,955.07	77,938.50	21,741.38	27,388.45	18,066.21	9,654.95	16,689.57	20,508.86	33,386.77	15,379.75	31,961.36	316,607.03
Other Income (Expense)													
Interest & dividend income	0.00	0.00	0.00	0.00	0.00	2,584.38	95.85	215.56	326.81	215.87	102.49	33,859.66	37,400.21
Other (see detail below)	(1,458.11)	(246.32)	(31,534.89)	(11.70)	(146.61)	1,444.77	(999.06)	(5,407.87)	(1,095.87)	(103.11)	(5,122.43)	(2,744.40)	(47,425.60)
Total Other Income (Expense)	(1,458.11)	(246.32)	(31,534.89)	(11.70)	(146.61)	4,029.15	(903.41)	(5,192.32)	(769.06)	112.56	(5,019.94)	31,115.26	(10,025.39)
Detail of "Other"													
Other income	0.00	0.00	0.00	0.00	0.00	11,537.00	0.00	0.00	0.00	0.00	0.00	0.00	11,537.00
Pension and OPRB expense	(106.12)	(83.33)	(251.62)	(147.09)	(147.09)	(147.09)	(147.09)	(147.09)	(138.99)	(146.19)	(146.19)	(146.19)	(1,754.28)
Other expenses	201.35	30.42	(505.45)	0.35	0.48	(129.60)	29.38	30.34	30.51	30.48	29.97	30.75	(220.99)
Charitable contributions	(1,500.00)	0.00	0.00	0.00	0.00	0.00	(1,000.00)	0.00	(1,000.00)	0.00	(5,025.25)	(2,500.00)	(11,025.25)
Penalties	(53.34)	(193.41)	(30,777.82)	135.01	0.00	(9,815.54)	118.85	(5,291.12)	12.61	12.60	19.04	(123.96)	(45,962.08)
Total other detail	(1,458.11)	(246.32)	(31,534.89)	(11.70)	(146.61)	1,444.77	(999.06)	(5,407.87)	(1,095.87)	(103.11)	(5,122.43)	(2,744.40)	(47,425.60)
Interest Charges													
Interest on LTD	12,360.64	12,926.71	13,035.84	15,946.67	16,428.47	17,232.45	14,097.84	14,097.84	14,097.84	12,505.39	13,440.62	14,266.00	170,457.11
Amortization of debt expense	215.84	215.84	215.84	264.61	264.61	272.11	230.09	228.89	228.89	203.63	203.69	209.27	2,753.31
Interest on short-term borrowing	7,584.11	6,223.67	7,245.18	9,227.18	8,728.67	9,534.06	9,222.22	9,603.20	9,863.88	10,327.09	9,756.47	11,167.54	108,583.23
Other	35.79	0.00	0.00	11.77	0.00	0.00	0.00	1,784.29	7.18	0.00	0.00	1,274.99	3,114.02
Total Interest Charges	20,216.18	19,366.22	20,496.84	25,452.23	25,421.75	27,138.62	23,550.15	25,714.22	24,197.77	23,036.11	23,400.78	26,918.80	284,907.67

Natural Gas Marketing (PESCO)

Income Statement Detail by Natural Acct (QTD/YTD/12ME)

December 31, 2017

Case No.: 17-1916-GA-CRS

Peninsula Energy Services Company, Inc.

Exhibit C-3 "Financial Statements"

	For the Three Months Ended				For the Twelve Months Ended						
	Current Yr	Prior Yr	Variance	% Var	Current Yr	Prior Yr	Variance	% Var	2015	Variance	% Var
Statement of Income											
Revenue	58,399,647	32,175,184	26,224,463	81.51%	184,519,140	95,413,872	89,105,268	93.39%	58,247,095	39,166,778	69.63%
Cost of Sales	61,936,352	31,533,319	30,403,032	96.42%	182,307,226	90,783,421	91,523,805	100.82%	52,659,933	38,123,488	72.40%
Gross Margin	(3,536,705)	641,865	(4,178,570)	(651.00%)	2,211,914	4,630,452	(2,418,537)	(52.23%)	3,587,161	1,043,290	29.08%
Operating Expenses											
Business Unit											
Payroll & benefits	767,776	520,133	247,643	47.61%	2,381,014	1,481,050	899,964	60.77%	956,854	524,196	54.78%
Other business unit expenses	487,230	247,070	240,161	97.20%	1,261,898	617,694	644,204	104.29%	283,733	333,961	117.70%
Depreciation, ARC & Amort.	139,057	0	139,057	0.00%	212,597	0	212,597	0.00%	0	0	0.00%
Other taxes	74,292	42,344	31,947	75.45%	253,220	101,504	151,715	149.47%	72,921	28,583	39.20%
Corporate Services	144,676	77,555	67,121	86.55%	746,245	270,472	475,773	175.90%	193,403	77,069	39.85%
Corporate Overhead	178,241	95,921	82,320	85.82%	504,185	295,512	208,673	70.61%	222,874	72,638	32.59%
Total Operating Expenses	1,791,273	983,023	808,249	82.22%	5,359,158	2,766,232	2,592,926	93.73%	1,729,785	1,036,447	59.92%
Operating Income Before Transaction/Transition Costs	(5,327,977)	(341,158)	(4,986,819)	(1,461.73%)	(3,147,244)	1,864,219	(5,011,464)	(268.82%)	1,857,376	6,843	0.37%
Operating Income	(5,327,977)	(341,158)	(4,986,819)	(1,461.73%)	(3,147,244)	1,864,219	(5,011,464)	(268.82%)	1,857,376	6,843	0.37%
Total other income (expense)	(12,318)	(1,205)	(11,112)	(922.06%)	(135,204)	(17,158)	(118,046)	(688.00%)	(2,442)	(14,716)	(602.69%)
Income (Loss) Before Interest Charges	(5,340,295)	(342,363)	(4,997,931)	(1,459.83%)	(3,282,448)	1,847,061	(5,129,510)	(277.71%)	1,854,934	(7,873)	(0.42%)
Total interest charges	69,739	24,499	45,240	184.66%	114,701	60,754	53,947	88.80%	24,848	35,906	144.50%
Income (Loss) Before Income Taxes	(5,410,034)	(366,862)	(5,043,172)	(1,374.68%)	(3,397,149)	1,786,307	(5,183,457)	(290.18%)	1,830,087	(43,779)	(2.39%)
Income Taxes											
Operating (excl ESOP deduction)	(1,297,384)	(148,857)	(1,148,527)	(771.57%)	(473,226)	689,149	(1,162,375)	(168.67%)	709,687	(20,538)	(2.89%)
Non-Operating (excl ITC)	(1,264)	(308)	(956)	(310.39%)	(4,744)	(4,882)	138	2.83%	(828)	(4,054)	(489.61%)
Total Income Taxes	(1,298,648)	(149,165)	(1,149,483)	(770.61%)	(477,970)	684,267	(1,162,237)	(169.85%)	708,859	(24,592)	(3.47%)
Net Income from Continuing Operations	(4,111,388)	(217,698)	(3,893,688)	(1,788.58%)	(2,919,179)	1,102,040	(4,021,219)	(364.89%)	1,121,228	(19,188)	(1.71%)
Net Income	(4,111,388)	(217,698)	(3,893,688)	(1,788.58%)	(2,919,179)	1,102,040	(4,021,219)	(364.89%)	1,121,228	(19,188)	(1.71%)

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CPK Comparative P&L QTD/YTD/12ME-Corp&SS separate 11:10 AM

Natural Gas Marketing (PESCO)

Income Statement Detail by Natural Acct (QTD/YTD/12ME)

December 31, 2017

	For the Three Months Ended				For the Twelve Months Ended						
	Current Yr	Prior Yr	Variance	% Var	Current Yr	Prior Yr	Variance	% Var	2015	Variance	% Var
Operating Expense Summary											
Business Unit Direct											
Payroll											
Salaries	471,122	322,146	148,976	46.24%	1,708,238	982,466	725,772	73.87%	621,239	361,226	58.15%
OT, On Call & Comp Time	355	0	355	0.00%	3,860	8	3,852	48,888.83%	296	(288)	(97.33%)
Bonus/Incentive Pay	74,003	81,565	(7,562)	(9.27%)	209,928	262,724	(52,796)	(20.10%)	172,276	90,448	52.50%
Short-term Cash Bonus	39,686	0	39,686	0.00%	39,686	0	39,686	0.00%	0	0	0.00%
Long-term Cash Bonus	61,105	0	61,105	0.00%	61,105	0	61,105	0.00%	0	0	0.00%
Other Bonuses	9,000	0	9,000	0.00%	9,000	0	9,000	0.00%	0	0	0.00%
Other	0	0	0	0.00%	0	0	0	0.00%	17,406	(17,406)	(100.00%)
Total Payroll	655,271	403,711	251,559	62.31%	2,031,817	1,245,198	786,619	63.17%	811,217	433,980	53.50%
Benefits											
Claims-Health & Dental	42,930	27,222	15,708	57.70%	153,748	77,721	76,025	97.82%	44,730	32,991	73.76%
Employee withholding	(13,522)	(7,612)	(5,910)	(77.64%)	(47,205)	(27,749)	(19,456)	(70.12%)	(17,399)	(10,350)	(59.49%)
Admin fees, workers comp & other	12,739	8,219	4,519	54.99%	47,295	23,936	23,359	97.59%	12,931	11,005	85.10%
401K	41,283	22,974	18,309	79.69%	130,525	75,794	54,731	72.21%	44,990	30,805	68.47%
Other benefits	29,076	65,619	(36,543)	(55.69%)	64,836	86,149	(21,314)	(24.74%)	56,317	29,833	52.97%
Other (InterCo/InterDist/InterDept/Cap)	0	0	0	0.00%	0	0	0	0.00%	4,068	(4,068)	(100.00%)
Total Benefits	112,506	116,422	(3,917)	(3.36%)	349,197	235,852	113,345	48.06%	145,637	90,215	61.95%
Departmental Expenses											
Travel, meals & training	38,051	46,616	(8,566)	(18.38%)	191,666	100,801	90,865	90.14%	39,884	60,907	152.68%
Cell phones	6,437	4,989	1,448	29.03%	22,246	15,695	6,551	41.74%	12,634	3,061	24.23%
Other	43,442	21,788	21,654	99.38%	139,054	68,269	70,785	103.69%	47,656	20,613	43.25%
Total Departmental Expenses	87,929	73,393	14,536	19.81%	352,966	184,765	168,201	91.03%	100,184	84,582	84.43%

Vehicle Expenses											
Fuel	3,984	3,822	162	4.24%	13,354	9,846	3,508	35.62%	8,157	1,690	20.71%
Depreciation	12,220	8,961	3,259	36.38%	44,452	31,759	12,693	39.97%	18,030	13,730	76.15%
Insurance	2,309	1,870	440	23.53%	8,521	6,726	1,795	26.69%	4,195	2,531	60.33%
Other	4,501	848	3,653	430.69%	10,347	4,849	5,498	113.38%	1,281	3,568	278.50%
Total Vehicle Expenses	23,015	15,500	7,514	48.48%	76,674	53,180	23,493	44.18%	31,662	21,518	67.96%
Facilities & Operating Systems											
Rent & Leases	30,041	7,777	22,264	286.29%	62,976	30,925	32,051	103.64%	30,387	538	1.77%
Utilities	2,740	2,531	208	8.23%	10,202	11,188	(986)	(8.81%)	7,961	3,227	40.53%
Other operating expenses	7,874	2,270	5,604	246.85%	17,992	7,906	10,086	127.57%	11,354	(3,448)	(30.36%)
Maintenance	140,025	50	139,976	281,924.87%	140,075	50	140,025	282,024.87%	276	(226)	(81.98%)
Total Facilities & Op Sys Exp	180,680	12,628	168,052	1,330.80%	231,245	50,069	181,177	361.86%	49,978	91	0.18%
Outside Services											
Legal	2,451	3,105	(654)	(21.05%)	6,598	37,453	(30,855)	(82.38%)	26,208	11,245	42.91%
Consulting	51,298	123,894	(72,595)	(58.63%)	392,923	270,626	122,297	45.19%	32,450	238,176	733.99%
Total Outside Services	53,750	127,099	(73,349)	(57.71%)	399,521	308,079	91,442	29.68%	58,658	249,422	425.22%
Sales, Advertising & Communications											
Sales	1,651	0	1,651	0.00%	1,751	0	1,751	0.00%	1,000	(1,000)	(100.00%)
Other	56,250	475	55,775	11,746.59%	57,471	2,859	54,612	1,910.18%	3,944	(1,085)	(27.50%)
Total Sales, Advertising & Communications	57,901	475	57,426	12,094.31%	59,222	2,859	56,363	1,971.43%	4,944	(2,085)	(42.17%)
Credit, Collections & Customer Service											
Bad Debts	32,682	13,692	18,970	138.54%	74,478	3,660	70,818	1,934.81%	26,831	(23,170)	(86.36%)
Collection agencies & credit reports	3,886	2,716	1,170	43.06%	14,466	8,267	6,199	74.99%	6,007	2,259	37.61%
Customer satisfaction & other	17,514	0	17,514	0.00%	17,514	0	17,514	0.00%	340	(340)	(100.00%)
Total Credit, Collections & Customer Servic	54,062	16,409	37,654	229.48%	106,458	11,927	94,532	792.60%	33,178	(21,251)	(64.05%)
Bank/Merchant Fees	29,894	1,566	28,328	1,808.82%	34,482	6,815	27,668	406.01%	5,130	1,685	32.84%
Miscellaneous											
Fees, Assessments & Discounts	0	0	0	0.00%	1,328	0	1,328	0.00%	0	0	0.00%
Total Miscellaneous	0	0	0	0.00%	1,328	0	1,328	0.00%	0	0	0.00%
Total BU Direct O&M	1,255,007	767,203	487,804	63.58%	3,642,912	2,098,744	1,544,168	73.58%	1,240,587	858,157	69.17%
BU Taxes Other than Income	74,292	42,344	31,947	75.45%	253,220	101,504	151,715	149.47%	72,921	28,583	39.20%
BU Depr, Amort & ARC	139,057	0	139,057	0.00%	212,597	0	212,597	0.00%	0	0	0.00%
Total BU Direct Operating Exp.	1,468,355	809,547	658,808	81.38%	4,108,728	2,200,248	1,908,480	86.74%	1,313,508	886,740	67.51%
Total Corporate Services	144,676	77,555	67,121	86.55%	746,245	270,472	475,773	175.90%	193,403	77,069	39.85%
Total Corporate Overhead	178,241	95,921	82,320	85.82%	504,185	295,512	208,673	70.61%	222,874	72,638	32.59%
Total Operating Expenses	1,791,273	983,023	808,249	82.22%	5,359,158	2,766,232	2,592,926	93.73%	1,729,785	1,036,447	59.92%

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CPK Comparative P&L QTD/YTD/12ME-Corp&SS separate 11:10 AM
Natural Gas Marketing (PESCO)
Income Statement Detail by Natural Acct (QTD/YTD/12ME)
December 31, 2017

	For the Three Months Ended				For the Twelve Months Ended						
	Current Yr	Prior Yr	Variance	% Var	Current Yr	Prior Yr	Variance	% Var	2015	Variance	% Var
Shared Services & Corporate Support											
Corporate Services											
Payroll	43,870	17,421	26,449	151.82%	250,382	62,667	187,715	299.54%	52,751	9,917	18.80%
Benefits	7,913	3,932	3,981	101.23%	52,067	11,673	40,394	346.05%	8,974	2,698	30.07%
Department Expenses	7,692	1,549	6,142	396.43%	25,739	5,508	20,231	367.32%	5,220	288	5.51%
Vehicle Expenses	46	43	3	7.14%	192	166	26	15.55%	1	165	11,358.62%
Facilities & Operating Systems	58,208	28,192	30,016	106.47%	222,400	105,756	116,644	110.30%	48,826	56,929	116.60%
Insurance	22,455	16,980	5,475	32.24%	78,329	57,057	21,272	37.28%	57,937	(880)	(1.52%)
Outside Services	1,706	8,191	(6,485)	(79.18%)	98,165	21,091	77,073	365.43%	13,675	7,417	54.24%
Subtotal - Corp. Svc. O&M	141,889	76,308	65,581	85.94%	727,273	263,918	463,355	175.57%	187,384	76,534	40.84%
Taxes Other than Income	2,787	1,247	1,540	123.51%	18,972	6,554	12,418	189.48%	6,019	535	8.88%
Total Corporate Services	144,676	77,555	67,121	86.55%	746,245	270,472	475,773	175.90%	193,403	77,069	39.85%
Corporate Overhead											
Payroll	109,489	47,946	61,543	128.36%	279,104	145,355	133,749	92.02%	108,284	37,071	34.23%
Benefits	15,217	7,482	7,735	103.38%	51,948	26,300	25,648	97.52%	20,998	5,302	25.25%
Department Expenses	9,649	10,437	(787)	(7.54%)	30,737	25,851	4,886	18.90%	12,178	13,674	112.28%
Vehicle Expenses	1,661	516	1,146	222.04%	4,901	1,724	3,177	184.28%	1,135	589	51.87%
Facilities & Operating Systems	269	222	47	21.16%	1,083	712	371	52.09%	389	323	82.94%
Insurance	122	107	15	13.82%	593	503	90	17.91%	253	249	98.32%
Outside Services	19,597	19,589	8	0.04%	77,982	66,492	11,490	17.28%	52,875	13,618	25.75%
Investor Relations	4,352	437	3,915	896.02%	18,307	1,929	16,378	849.02%	5,995	(4,066)	(67.82%)
Sales, Advertising & Communications	3,920	4,669	(749)	(16.05%)	10,819	11,003	(184)	(1.67%)	9,058	1,945	21.47%
Credit, Collections & Customer Service	0	3	(3)	(100.00%)	8	42	(42)	(100.00%)	30	12	39.54%
Fees & Assessments	9,887	2,284	7,603	332.83%	15,617	7,984	7,633	95.60%	6,602	1,382	20.93%
Subtotal - Corp. OH O&M	174,163	93,691	80,472	85.89%	491,091	287,895	203,196	70.58%	217,798	70,097	32.18%

Taxes Other than Income	4,079	2,230	1,849	82.90%	13,094	7,617	5,477	71.91%	5,076	2,541	50.05%
Total Corporate Overhead	178,241	95,921	82,320	85.82%	504,185	295,512	208,673	70.61%	222,874	72,638	32.59%

Natural Gas Marketing (PESCO)
Income Statement Detail by Natural Acct (QTD/YTD/12ME)
December 31, 2017

	For the Three Months Ended				For the Twelve Months Ended						
	Current Yr	Prior Yr	Variance	% Var	Current Yr	Prior Yr	Variance	% Var	2015	Variance	% Var
Other Support											
BU Depreciation, ARC & Amortization											
Depreciation	33,508	0	33,508	0.00%	36,681	0	36,681	0.00%	0	0	0.00%
Amortization	105,549	0	105,549	0.00%	175,916	0	175,916	0.00%	0	0	0.00%
Total BU Depr., ARC & Amort.	139,057	0	139,057	0.00%	212,597	0	212,597	0.00%	0	0	0.00%
BU Taxes Other than Income											
Payroll	34,985	24,541	10,444	42.56%	140,388	80,821	59,567	73.70%	52,892	27,928	52.80%
Property	(43,882)	17,704	(61,585)	(347.87%)	(6,796)	18,004	(24,800)	(137.75%)	300	17,704	5,901.20%
Revenue Related	0	0	0	0.00%	0	2,155	(2,155)	(100.00%)	19,579	(17,424)	(88.99%)
Miscellaneous	83,188	100	83,088	83,088.14%	119,628	525	119,103	22,686.20%	150	375	250.00%
Total BU Other Taxes	74,292	42,344	31,947	75.45%	253,220	101,504	151,715	149.47%	72,921	28,583	39.20%
Other Income (Expense)											
Other (see detail below)	(12,318)	(1,205)	(11,112)	(922.06%)	(135,204)	(17,158)	(118,046)	(688.00%)	(2,442)	(14,716)	(602.69%)
Total Other Income (Expense)	(12,318)	(1,205)	(11,112)	(922.06%)	(135,204)	(17,158)	(118,046)	(688.00%)	(2,442)	(14,716)	(602.69%)
Detail of "Other"											
Other expenses	214	120	94	78.35%	(358)	(729)	371	50.92%	357	(1,086)	(304.33%)
Charitable contributions	(3,500)	(1,000)	(2,500)	(250.00%)	(12,000)	(12,000)	0	0.00%	(2,500)	(9,500)	(380.00%)
Penalties	(9,032)	(325)	(8,707)	(2,675.57%)	(122,846)	(4,429)	(118,417)	(2,673.91%)	(299)	(4,130)	(1,382.68%)
Total other detail	(12,318)	(1,205)	(11,112)	(922.06%)	(135,204)	(17,158)	(118,046)	(688.00%)	(2,442)	(14,716)	(602.69%)
Interest Charges											
Interest on LTD	45,729	18,609	27,120	145.73%	78,211	47,078	31,132	66.13%	22,128	24,951	112.76%
Amortization of debt expense	799	328	471	143.79%	1,374	809	565	69.85%	111	698	626.15%
Interest on short-term borrowing	23,210	5,561	17,649	317.34%	35,116	12,867	22,250	172.92%	2,577	10,290	399.29%
Other	0	0	0	0.00%	0	0	0	0.00%	32	(32)	(100.00%)
Total Interest Charges	69,739	24,499	45,240	184.66%	114,701	60,754	53,947	88.80%	24,848	35,906	144.50%

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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): February 26, 2019

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	001-11590	51-0064146
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(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)

(Former name, former address and former fiscal year, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02. Results of Operations and Financial Condition.

On February 26, 2019, Chesapeake Utilities Corporation issued a press release announcing its financial results for the quarter and year ended December 31, 2018. A copy of the press release is attached as Exhibit 99.1 hereto and is incorporated by reference herein.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibit 99.1 - Press Release of Chesapeake Utilities Corporation, dated February 26, 2019.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned hereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

/s/ Beth W. Cooper

Beth W. Cooper

Executive Vice President, Chief Financial Officer, and
Assistant Corporate Secretary

Date: February 26, 2019

1-1-1-1

FOR IMMEDIATE RELEASE
February 26, 2019
NYSE Symbol: CPK

CHESAPEAKE UTILITIES CORPORATION REPORTS FOURTH QUARTER AND FISCAL YEAR 2018 RESULTS

- **GAAP 2018 EPS of $3.45 exceeded Company guidance**
- **GAAP earnings totaled $3.45 per share (diluted)** in 2018 compared to $3.55 per share in 2017. The 2017 earnings included the one-time positive impact of $0.87 per share for the United States Tax Cuts and Jobs Act ("TCJA")**
- **Adjusted (non-GAAP) earnings increased to $3.31 per share in 2018 from $2.89 in 2017**
- **Recently constructed pipeline projects generated $12.9 million in gross margin* in 2018 and are expected to generate $23.6 million in annual gross margin going forward**
- **Key regulatory initiatives as well as ongoing infrastructure improvement programs contributed $8.6 million of incremental gross margin in 2018**
- **Growth in the propane operations and Aspire Energy of Ohio LLC ("Aspire Energy") added $3.1 million of gross margin in 2018**
- **$9.6 million was passed on as savings to regulated energy customers as a result of lower federal income taxes from TCJA**

Dover, Delaware — Chesapeake Utilities Corporation (NYSE: CPK) ("Chesapeake Utilities" or the "Company") today announced financial results for the year and the fourth quarter ended December 31, 2018.
Reported net income for 2018 was $56.6 million, or $3.45 per share compared to $58.1 million, or $3.55 per share for 2017. Adjusted 2018 net income increased to $54.3 million, or $3.31 per share, from $47.3 million, or $2.89 per share in 2017. Continued growth across the Company's businesses, key regulatory initiatives and colder weather were the most significant contributors to higher earnings in 2018.

Fourth quarter 2018 GAAP net income was $17.8 million, or $1.08 per share compared to $26.1 million, or $1.59 per share in 2017. Adjusted fourth quarter 2018 net income increased to $18.2 million, or $1.10 per share, from $15.3 million, or $0.93 per share in 2017. Higher 2018 fourth quarter adjusted earnings reflect continued growth across the Company's businesses. A detailed discussion of operating results begins on page 3.

"Just two short months ago, I was appointed President and CEO of this very special company. I continue to be energized by everything I see, including the results discussed herein, our employees which drive our success, our commitment to providing safe, clean, reliable energy services to existing and new communities, and other potential growth opportunities," stated Jeffry M. Householder, President and Chief Executive Officer. "2018 was another remarkable year by any measure. 2018 EPS exceeded our guidance of 17 percent growth over 2017 adjusted earnings. Earnings were driven by our highest ever increase in gross margin, which reflected strong growth across our regulated and unregulated energy businesses. Given the opportunities in our existing businesses and ongoing projects and initiatives, we are well positioned for future growth. It is an exciting time to lead this Company forward," Mr. Householder added.

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Significant Items Impacting Earnings

Results for the year and fourth quarter of 2018 and 2017 were impacted by the following significant items:

For the year ended December 31,	2018		2017	
(in thousands, except per share data)	Net Income	EPS	Net Income	EPS
Reported (GAAP) Earnings	$ 56,580	$ 3.45	$ 58,124	$ 3.55
Unrealized mark-to-market ("MTM") activity	(3,706)	(0.23)	3,499	0.21
One-time impact from TCJA associated with deferred tax liability revaluation	—	—	(14,299)	(0.87)
Non-recurring separation expenses associated with a former executive	1,421	0.09	—	—
Adjusted (Non-GAAP) Earnings*	$ 54,295	$ 3.31	$ 47,324	$ 2.89

For the period ended December 31,	Fourth Quarter 2018		Fourth Quarter 2017	
(in thousands, except per share data)	Net Income	EPS	Net Income	EPS
Reported (GAAP) Earnings	$ 17,801	$ 1.08	$ 26,101	$ 1.59
Unrealized MTM activity	401	0.02	3,467	0.21
One-time impact from TCJA associated with deferred tax liability revaluation	—	—	(14,299)	(0.87)
Adjusted (Non-GAAP) Earnings	$ 18,202	$ 1.10	$ 15,269	$ 0.93

The Company's reported EPS was $3.45 for 2018 compared to $3.55 in 2017. 2018 adjusted (non-GAAP) EPS totaled $3.31, representing 14.5 percent growth over 2017 adjusted (non-GAAP) EPS of $2.89. Fourth quarter 2018 adjusted (non-GAAP) EPS of $1.10 reflects growth of 18.3 percent over fourth quarter adjusted (non-GAAP) EPS of $0.93 in 2017.

Hurricane Michael Update

In October 2018, Hurricane Michael passed through Florida Public Utilities Company's ("FPU") electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure resulting in 100 percent of its customers losing electrical service. FPU has restored service to those customers who were able to accept power following Hurricane Michael after a significant hurricane restoration effort. In conjunction with restoring these services, FPU expended over $60 million to restore service, which has been recorded as new plant and equipment or charged against FPU's accumulated depreciation and storm reserve. The Company has begun preparing the necessary regulatory filings to seek recovery for the costs incurred, including replenishment of the Company's storm reserve. In conjunction with the hurricane-related expenditures, the Company executed two 13-month unsecured term loans as temporary financing, each in the amount of $30 million. The interest cost associated with these loans is LIBOR plus 75 basis points. One of the term loans was executed in December of 2018 and the other was executed on January 31, 2019. The storm did not have a material impact on the Company's financial results in 2018 as services were restored to a majority of its customers, and is not expected to have a significant impact going forward as the Company will be seeking recovery of the storm costs through rates.

**This press release includes references to non-Generally Accepted Accounting Principles ("GAAP") financial measures, including gross margin, adjusted earnings and Adjusted EPS. A "non-GAAP financial measure" is generally defined as a numerical measure of a company's historical or future performance that includes or excludes amounts, or that is subject to adjustments, so as to be different from the most directly comparable measure calculated or presented in accordance with GAAP. Our management believes certain non-GAAP financial measures, when considered together with GAAP financial measures, provide information that is useful to investors in understanding period-over-period operating results separate and apart from items that may, or could, have a disproportionately positive or negative impact on results in any particular period.*

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The Company calculates "gross margin" by deducting the cost of sales from operating revenues. Cost of sales includes the purchased fuel cost for natural gas, electricity and propane, and the cost of labor spent on direct revenue-producing activities and excludes depreciation, amortization and accretion. Other companies may calculate gross margin in a different manner. Gross margin should not be considered an alternative to operating income or net income, both of which are determined in accordance with GAAP. The Company believes 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 the Company under its allowed rates for regulated operations and under its competitive pricing structures for unregulated businesses. The Company's management uses gross margin in measuring its business units' performance. This press release also includes gross margin that excludes the impact of unusual items, such as the pass-through to customers of lower federal income taxes resulting from TCJA. The Company calculates "adjusted earnings" by adjusting reported (GAAP) earnings to exclude the impact of certain significant non-cash items, including the impact of realized MTM gains (losses), and one-time charges, such as severance charges. "Adjusted EPS" is calculated by dividing adjusted earnings by the weighted average common shares outstanding.

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

Operating Results for the Years Ended December 31, 2018 and 2017

Consolidated Results

	Year Ended December 31,			
(in thousands)	**2018**	**2017**	**Change**	**Percent Change**
Gross margin before the TCJA impact	**$ 316,310**	$ 279,669	$ 36,641	13.1%
Pass-through of lower taxes to regulated energy customers	**(9,562)**	—	(9,562)	N/A
Gross margin	**306,748**	279,669	27,079	9.7%
Depreciation, amortization and property taxes	**56,948**	51,782	5,166	10.0%
Non-recurring executive separation expenses	**1,548**	—	1,548	N/A
Other operating expenses	**153,632**	140,467	13,165	9.4%
Operating income	**$ 94,620**	$ 87,420	$ 7,200	8.2%

Operating income, for the year ended December 31, 2018, increased by $7.2 million, or 8.2 percent, compared to the same period in 2017. This increase was driven by a $27.1 million, or 9.7 percent, increase in gross margin, which is net of $9.6 million of estimated customer refunds for lower taxes associated with the TCJA. The increased margin was partially offset by a $5.2 million increase in depreciation, amortization and property taxes and a $13.2 million increase in other operating expenses. The pass-through of lower taxes to customers is completely offset by an equivalent reduction in income tax expenses for the Regulated Energy segment. Excluding the estimated pass-through of lower taxes to customers, gross margin and operating income increased by $36.6 million (13.1 percent) and $16.8 million (19.2 percent), respectively.

Regulated Energy Segment

(in thousands)	Year Ended December 31, 2018	2017	Change	Percent Change
Gross margin before the TCJA impact	$ 233,015	$ 207,541	$ 25,474	12.3%
Pass-through of lower taxes to regulated energy customers	(9,562)	—	(9,562)	N/A
Gross margin	223,453	207,541	15,912	7.7%
Depreciation, amortization and property taxes	46,523	42,337	4,186	9.9%
Other operating expenses	97,715	90,620	7,095	7.8%
Operating income	$ 79,215	$ 74,584	$ 4,631	6.2%

Operating income for the Regulated Energy segment increased by $4.6 million, or 6.2 percent, for the year ended December 31, 2018 compared to the same period in 2017. This increase was driven by a $25.5 million increase in gross margin before the impact of the TCJA, which was partially offset by $4.2 million in higher depreciation and $7.1 million in other operating expenses associated with gross margin growth. Excluding the estimated pass-through of lower taxes to customers, operating income increased by $14.2 million, or 19.0 percent.

The key components of the increase in gross margin are shown below:

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

*Eastern Shore Natural Gas Company, the Company's interstate natural gas transmission subsidiary
**Peninsula Pipeline Company, Inc., the Company's Florida intrastate pipeline subsidiary
***As a result of the TCJA and in compliance with directives by federal and state regulatory commissions, the Company reserved or refunded an estimated $9.6 million during 2018. In some jurisdictions, refunds have been made to customers, while in other jurisdictions, the Company has established reserves until agreements are approved and permanent changes are made to customer rates. The reserves and lower customer rates are equal to the estimated reduction in federal income taxes due to the TCJA and have no material impact on after-tax earnings from the Regulated Energy segment.

The major components of the increase in other operating expenses are as follows:

(in thousands)	Other Operating Expenses
Depreciation, amortization and property taxes associated with recent capital investments	$ 4,186
Payroll expense (increased staffing and annual salary increases)	2,426
Outside services to support growth	2,182
Facilities costs to support growth and maintenance costs to maintain system integrity	1,661
Other operating expenses, including vehicle, other taxes and credit collections due to growth and timing of collections	869
Incentive compensation costs (based on actual results compared to targets and timing of accruals)	(737)
Regulatory expenses due to fewer proceedings in 2018	(661)
Other employee-related expenses	514
Early termination of facility lease due to consolidation of operations facilities	323
Cumulative change in other expenses	518
Year-over-year increase in other operating expenses	**$ 11,281**

Unregulated Energy Segment

	Year Ended December 31,			
(in thousands)	2018	2017	Change	Percent Change
Gross margin	$ **83,798**	$ 72,572	$ 11,226	15.5%
Depreciation, amortization and property taxes	**10,282**	9,287	995	10.7%
Other operating expenses	**56,615**	50,654	5,961	11.8%
Operating income	$ **16,901**	$ 12,631	$ 4,270	33.8%

Given the impact of MTM activity and increased infrastructure and risk management system costs, Peninsula Energy Services Company, Inc. ("PESCO")'s results continue to be reported separate from the rest of the Unregulated Energy segment:

Unregulated Energy Segment, excluding PESCO

	Year Ended December 31,			
(in thousands)	2018	2017	Change	Percent Change
Gross margin	$ **77,197**	$ **70,360**	$ 6,837	9.7%
Depreciation, amortization and property taxes	**9,678**	9,081	597	6.6%
Other operating expenses	**49,197**	45,504	3,693	8.1%
Operating income	$ **18,322**	$ 15,775	$ 2,547	16.1%

Operating income for the Unregulated Energy segment, excluding PESCO, increased by $2.5 million in 2018 compared to 2017. Gross margin increased by $6.8 million, or 9.7 percent, due primarily to higher performance from the propane operations and at Aspire Energy, as well as more normal weather. Other operating expenses increased by $3.7 million, and depreciation, amortization and property taxes increased by $597,000 as a result of the margin growth.

The major components of the increase in gross margin (excluding PESCO results) are shown below:

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

The key components of the increase in other operating expenses (excluding PESCO expenses) are as follows:

(in thousands)	Other Operating Expenses
Payroll expense (increased staffing and annual salary increases)	$ 1,923
Facilities and maintenance costs to support growth and on-going compliance activities	953
Depreciation, amortization and property taxes associated with recent capital investments	597
Other employee-related costs	586
Cumulative change in other expenses	231
Year-over-year increase in other operating expenses	$ 4,290

PESCO

(in thousands)	Year Ended December 31, 2018	2017	Change
Gross margin	**$ 6,601**	$ 2,212	$ 4,389
Depreciation, amortization and property taxes	**604**	206	398
Other operating expenses	**7,418**	5,150	2,268
Operating loss	**$ (1,421)**	$ (3,144)	$ 1,723

PESCO's operating results in 2018 improved by $1.7 million compared to 2017 due primarily to MTM gains recorded in 2018 compared to MTM losses recorded in 2017, partially offset by the extraordinary costs of meeting demand requirements in the Mid-Atlantic region during the first quarter associated with the 2018 Bomb Cyclone, capacity constraints and other market conditions. PESCO's other operating expenses increased by $2.3 million compared to the same period in 2017, reflecting increased staffing, infrastructure and risk management systems to support PESCO's growth. See a more detailed discussion later in the press release (page 19) and in the Company's 2018 Annual Report on Form 10-K.

Operating Results for the Quarters Ended December 31, 2018 and 2017

Consolidated Results

(in thousands)	Three Months Ended December 31, 2018	2017	Change	Percent Change
Gross margin before the TCJA impact	$ **87,051**	$ 75,020	$ 12,031	16.0%
Pass-through of lower taxes to regulated energy customers	**(1,981)**	—	(1,981)	N/A
Gross margin	**85,070**	75,020	10,050	13.4%
Depreciation, amortization and property taxes	**14,799**	13,367	1,432	10.7%
Other operating expenses	**41,341**	38,025	3,316	8.7%
Operating income	$ **28,930**	$ 23,628	$ 5,302	22.4%

Operating income during the fourth quarter of 2018 increased by $5.3 million, or 22.4 percent, compared to the same period in 2017. Pass-through of lower taxes to regulated energy customers, as a result of the TCJA, reduced margin and operating income by approximately $2.0 million, and were offset by an equal reduction in income taxes. Gross margin before the effect of the TCJA increased by $12.0 million, or 16.0 percent, and operating income increased by $7.3 million, or 30.8 percent. Depreciation expense increased by $1.4 million, and other operating expenses increased by $3.3 million, reflecting increased investment and costs to support growth.

Regulated Energy Segment

(in thousands)	Three Months Ended December 31, 2018	2017	Change	Percent Change
Gross margin before the TCJA impact	$ **62,509**	$ 56,394	$ 6,115	10.8%
Pass-through of lower taxes to regulated energy customers	**(1,981)**	—	(1,981)	N/A
Gross margin	**60,528**	56,394	4,134	7.3%
Depreciation, amortization and property taxes	**12,121**	10,926	1,195	10.9%
Other operating expenses	**26,122**	23,888	2,234	9.4%
Operating income	$ **22,285**	$ 21,580	$ 705	3.3%

Operating income for the Regulated Energy segment increased by $705,000, or 3.3 percent, in the fourth quarter of 2018 compared to the same period in 2017. This increase was driven by a $4.1 million increase in gross margin, offset by $3.4 million in higher depreciation and other operating expenses associated with the margin growth. Fourth quarter gross margin and operating income were also impacted by customer refunds of $2.0 million, due to the pass-through of lower taxes to regulated energy customers as a result of the TCJA. The decrease in gross margin and operating income from the customer refunds was completely offset by an equal reduction in income tax expense. Excluding the estimated pass-through to customers of lower taxes, operating income increased by $2.7 million, or 12.4 percent. This increase in operating income reflects continued growth in the natural gas distribution operations and expansions at Peninsula Pipeline and Eastern Shore, as shown in the table that follows.

The key components of the increase in gross margin are shown below:

(in thousands)	Margin Impact
Eastern Shore and Peninsula Pipeline service expansions	$ 3,743
Natural gas growth (excluding service expansions)	1,566
Florida GRIP	346
Florida electric reliability/modernization program	285
Other	175
Total	6,115
Less: Pass-through to regulated energy customers of lower taxes resulting from TCJA*	(1,981)
Quarter-over-quarter increase in gross margin	**$ 4,134**

*As a result of the TCJA and in compliance with directives by federal and state regulatory commissions, the Company reserved or refunded an estimated $2.0 million during the fourth quarter of 2018. In some jurisdictions, refunds have been made to customers, while in other jurisdictions, the Company has established reserves until final agreements are approved and permanent changes are made to customer rates. The reserves and lower customer rates are equal to the estimated reduction in federal income taxes due to the TCJA and have no material impact on after-tax earnings from the Regulated Energy segment.

The major components of the increase in other operating expenses are as follows:

(in thousands)	Other Operating Expenses
Outside services to support growth	$ 2,150
Depreciation, amortization and property taxes associated with recent capital projects	1,195
Incentive compensation costs (based on actual results compared to targets and timing of accruals)	(1,140)
Payroll expense (increased staffing and annual salary increases)	571
Other employee-related expenses	207
Cumulative change in other expenses	446
Quarter-over-quarter increase in other operating expenses	**$ 3,429**

Unregulated Energy Segment

	Three Months Ended December 31,			
(in thousands)	2018	2017	Change	Percent Change
Gross margin	**$ 24,649**	$ 18,745	$ 5,904	31.5%
Depreciation, amortization and property taxes	**2,645**	2,403	242	10.1%
Other operating expenses	**15,344**	14,337	1,007	7.0%
Operating income	**$ 6,660**	$ 2,005	$ 4,655	232.2%

As with full year results, PESCO's quarterly results are shown separate from the rest of the Unregulated Energy Segment.

Unregulated Energy Segment, excluding PESCO

(in thousands)	Three Months Ended December 31, 2018	2017	Change	Percent Change
Gross margin	**$ 22,560**	**$ 22,282**	$ 278	1.2 %
Depreciation, amortization and property taxes	**2,497**	2,308	189	8.2 %
Other operating expenses	**13,203**	12,641	562	4.4 %
Operating income	**$ 6,860**	$ 7,333	$ (473)	(6.5)%

Operating income for the Unregulated Energy segment, excluding PESCO, decreased by $473,000 for the three months ended December 31, 2018, compared to the same period in 2017. The decrease in operating income reflects a $278,000 increase in gross margin, offset by $562,000 in higher other operating expenses.

The major components of the increase in gross margin, excluding PESCO results, are shown below:

(in thousands)	Margin Impact
Unregulated Energy customer growth	$ 1,348
Propane operations - decreased retail margins per gallon for certain customer classes	(500)
Warmer weather in the Mid-Atlantic	(475)
Other	(95)
Quarter-over-quarter increase in gross margin	**$ 278**

Other operating expenses were higher as a result of additional personnel, and outside services to support growth in these businesses, offset by lower incentive compensation costs as a result of actual results relative to pre-established targets and the timing of associated accruals.

The major components of the increase in other operating expenses are as follows:

(in thousands)	Other Operating Expenses
Outside services and facilities maintenance costs	$ 674
Incentive compensation costs (based on period-over-period results compared to targets and the timing of accruals)	(643)
Payroll expense (increased staffing and annual salary increases)	495
Cumulative change in other expenses	36
Quarter-over-quarter increase in other operating expenses	**$ 562**

PESCO

(in thousands)	Three Months Ended December 31, 2018	2017	Change
Gross margin	$ 2,089	$ (3,537)	$ 5,626
Depreciation, amortization and property taxes	148	95	53
Other operating expenses	2,141	1,696	445
Operating loss	$ (200)	$ (5,328)	$ 5,128

For the three months ended December 31, 2018, PESCO's gross margin improved by $5.6 million, compared to the same period in 2017, due primarily to the absence of the unrealized MTM loss recorded in the fourth quarter of 2017. PESCO's operating expenses increased by $498,000, compared to the same period in 2017, reflecting increased planned expenses for staff, infrastructure and risk management systems to keep pace with growth. A more detailed discussion of PESCO's results for the fourth quarters of 2018 and 2017 is provided later in this release (page 19) and in the Company's 2018 Annual Report on Form 10-K.

Safe Harbor for Forward-Looking Statements

The Company makes statements in this Press Release that does not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as "project," "believe," "expect," "anticipate," "intend," "plan," "estimate," "continue," "potential," "forecast" or other similar words, or future or conditional verbs such as "may," "will," "should," "would" or "could." These statements represent the Company's intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. Forward-looking statements speak only as of the date they are made or as of the date indicated and we do not undertake any obligation to update forward-looking statements as a result of new information, future events or otherwise. These statements are subject to many risks and uncertainties. In addition to the risk factors described under *Item 1A, Risk Factors*, in the Company's 2018 Annual Report on Form 10-K, the following important factors, among others, could cause actual future results to differ materially from those expressed in the forward-looking statements:

- state and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed and the degree to which competition enters the electric and natural gas industries;
- the outcomes of regulatory, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the related costs are adequately covered by insurance or recoverable in rates;
- the impact of significant changes to current tax regulations and rates;
- the timing of certification authorizations associated with new capital projects and the ability to construct facilities at or below estimated costs;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now, or may in the future, own or operate;
- possible increased federal, state and local regulation of the safety of our operations;
- the economy in our service territories or markets, the nation, and worldwide, including the impact of economic conditions (which we do not control) on demand for electricity, natural gas, propane or other fuels;
- risks related to cyber-attacks or cyber-terrorism that could disrupt our business operations or result in failure of information technology systems;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- customers' preferred energy sources;
- industrial, commercial and residential growth or contraction in our markets or service territories;

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- the effect of competition on our businesses;
- the timing and extent of changes in commodity prices and interest rates;
- the effect of spot, forward and future market prices on our various energy businesses;
- the extent of our success in connecting natural gas and electric supplies to transmission systems, establishing and maintaining key supply sources; and expanding natural gas and electric markets;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the capital-intensive nature of our regulated energy businesses;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the ability to successfully execute, manage and integrate a merger, acquisition or divestiture of assets or businesses and the related regulatory or other conditions associated with the merger, acquisition or divestiture;
- the impact on our costs and funding obligations, under our pension and other post-retirement benefit plans, of potential downturns in the financial markets, lower discount rates, and costs associated with health care legislation and regulation;
- the ability to continue to hire, train and retain appropriately qualified personnel; and
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies.

Conference Call

Chesapeake Utilities Corporation will host a conference call on March 1, 2019 at 10:30 a.m. Eastern Time to discuss the Company's financial results for the year and quarter ended December 31, 2018. To participate in this call, dial 855.801.6270 and reference Chesapeake Utilities' 2018 Financial Results Conference Call. To access the replay recording of this call, please visit the Company's website at CPK Earnings Results or download the replay on your mobile device by accessing the Audiocast section of the Company's Investor Relations App.

About Chesapeake Utilities Corporation

Chesapeake Utilities is a diversified energy company engaged in natural gas distribution, transmission, gathering and processing, and marketing; electricity generation and distribution; propane gas operations; and other businesses. Information about Chesapeake Utilities and its family of businesses is available at http://www.chpk.com or through its Investor Relations App.

Please note that Chesapeake Utilities Corporation is not affiliated with Chesapeake Energy, an oil and natural gas exploration company headquartered in Oklahoma City, Oklahoma.

For more information, contact:

Beth W. Cooper
Executive Vice President, Chief Financial Officer, and Assistant Corporate Secretary
302.734.6799

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Financial Summary

(in thousands, except per-share data)

	Year Ended		Fourth Quarter	
For the Periods Ended December 31,	**2018**	**2017**	**2018**	**2017**
Gross Margin				
Regulated Energy	$ 223,453	$ 207,541	$ 60,528	$ 56,394
Unregulated Energy	83,798	72,572	24,649	18,745
Other businesses and eliminations	(503)	(444)	(107)	(119)
Total Gross Margin	$ 306,748	$ 279,669	$ 85,070	$ 75,020
Operating Income				
Regulated Energy	$ 79,215	$ 74,584	$ 22,285	$ 21,580
Unregulated Energy	16,901	12,631	6,660	2,005
Other businesses and eliminations	(1,496)	205	(15)	43
Total Operating Income	$ 94,620	$ 87,420	$ 28,930	$ 23,628
Other expense, net	(615)	(2,342)	(410)	(486)
Interest charges	16,431	12,645	4,456	3,513
Income taxes	20,994	14,309	6,263	(6,472)
Net Income	$ 56,580	$ 58,124	$ 17,801	$ 26,101
Earnings Per Share of Common Stock				
Basic	$ 3.46	$ 3.56	$ 1.09	$ 1.60
Diluted	$ 3.45	$ 3.55	$ 1.08	$ 1.59

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Financial Summary Highlights

Key variances for the year ended December 31, 2018 included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2017 Reported Results	$ 72,433	$ 58,124	$ 3.55
Adjusting for unusual items:			
Absence of the 2017 deferred tax revaluation benefit associated with the TCJA	—	(14,299)	(0.87)
Net impact of PESCO's MTM activity	10,423	7,602	0.46
One-time separation expenses associated with a former executive	(1,548)	(1,421)	(0.09)
Absence of Xeron expenses, including 2017 wind-down expenses	829	605	0.04
	9,704	(7,513)	(0.46)
Increased (Decreased) Gross Margins:			
Eastern Shore and Peninsula Pipeline service expansions*	9,709	7,082	0.43
Pass-through of lower taxes to regulated energy customers[1]	(9,562)	(6,975)	(0.42)
Natural gas growth (excluding service expansions)	5,911	4,311	0.26
Implementation of Eastern Shore settled rates*[2]	5,803	4,233	0.26
Impact on PESCO from Bomb Cyclone and pipeline capacity constraints	(5,545)	(4,044)	(0.25)
Colder weather	5,046	3,680	0.22
Unregulated Energy growth, excluding PESCO	3,140	2,290	0.14
Florida electric reliability/modernization program*	1,516	1,106	0.07
Florida GRIP*	1,277	932	0.06
Other margin for PESCO operations (net)	(489)	(357)	(0.02)
	16,806	12,258	0.75
Decreased (Increased) Other Operating Expenses[3]:			
Depreciation, asset removal and property taxes	(4,779)	(3,486)	(0.21)
Payroll expense (increased staffing and annual salary increases)	(4,349)	(3,172)	(0.19)
Facilities maintenance costs	(2,687)	(1,960)	(0.12)
Operating expenses to increase staffing, infrastructure and risk management systems necessary to support growth for PESCO[3]	(2,665)	(1,944)	(0.12)
Outside services	(2,182)	(1,592)	(0.10)
Vehicle, other taxes and credit collections	(1,551)	(1,131)	(0.07)
Other employee-related expenses	(1,100)	(802)	(0.05)
Incentive compensation costs	734	535	0.03
Outside regulatory costs and early termination of facility lease due to consolidation of operations facilities	238	173	0.01
	(18,341)	(13,379)	(0.82)
Interest charges	(3,786)	(2,762)	(0.17)
Income taxes - Regulated Energy [1]	—	6,975	0.42
Other income tax effects - primarily the impact of income rate tax changes on Unregulated businesses	—	2,323	0.14
Net Other changes	758	554	0.04
Year ended December 31, 2018 Reported Results	**$ 77,574**	**$ 56,580**	**$ 3.45**

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

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

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

*** See the Major Projects and Initiatives table later in this press release.**

Key variances for the quarter ended December 31, 2018 included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Fourth Quarter 2017 Reported Results	$ 19,629	$ 26,101	$ 1.59
Adjusting for unusual items:			
Absence of the Q4 2017 Unregulated Energy tax benefit associated with TCJA	—	(14,299)	(0.87)
Net impact of PESCO's MTM activity	5,216	3,859	0.23
	5,216	(10,440)	(0.64)
Increased (Decreased) Gross Margins:			
Eastern Shore and Peninsula Pipeline service expansions*	3,743	2,769	0.17
Pass-through of lower taxes to regulated energy customers[1]	(1,981)	(1,465)	(0.09)
Natural gas growth (excluding service expansions)	1,566	1,158	0.07
Unregulated energy growth, excluding PESCO	1,329	983	0.06
Implementation of Eastern Shore settled rates*[2]	(641)	(474)	(0.03)
Lower retail propane margins per gallon in certain customer classes	(500)	(370)	(0.02)
Warmer weather	(351)	(260)	(0.02)
Other margin for PESCO operations (net)	409	303	0.02
Florida GRIP*	346	256	0.02
Florida electric reliability/modernization program*	285	211	0.01
	4,205	3,111	0.19
(Increased) Decreased Other Operating Expenses[3]:			
Outside services and facilities maintenance costs	(2,898)	(2,143)	(0.13)
Incentive compensation costs (based on period-over-period results)	1,783	1,319	0.08
Depreciation, asset removal and property taxes	(1,379)	(1,020)	(0.06)
Payroll expense (increased staffing and annual salary increases)	(1,065)	(788)	(0.05)
Operating expenses to increase staffing, infrastructure and risk management systems necessary to support growth for PESCO[3]	(498)	(368)	(0.02)
Other employee-related expenses	(351)	(259)	(0.02)
	(4,408)	(3,259)	(0.20)
Interest Charges	(943)	(698)	(0.04)
Income taxes - Regulated Energy [1]	—	1,465	0.09
Other income tax effects	—	1,253	0.08
Net Other Changes	365	268	0.01
Fourth Quarter 2018 Reported Results	$ 24,064	$ 17,801	$ 1.08

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

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

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

*** See the Major Projects and Initiatives table later in this press release.**

The following information highlights certain key factors contributing to the Company's results for the year and quarter ended December 31, 2018:

Recently Completed and Ongoing Major Projects and Initiatives

The Company constantly seeks and develops additional projects and initiatives to provide solutions for our customers and further increase shareholder value. The following represent the major projects and initiatives recently completed and currently underway. In the future, the Company will add new projects to this table when such projects are initiated.

	Gross Margin for the Period				
	Year Ended December 31,		Three Months Ended December 31,		Estimate for Fiscal
Project / Initiative	**2018**	**2017**	**2018**	**2017**	**2019**
(in thousands)					
Florida GRIP	**$ 14,731**	$ 13,454	**$ 3,798**	$ 3,452	$ 16,276
Eastern Shore Rate Case [1]	**9,496**	3,693	**2,687**	2,673	9,800
Florida Electric Reliability/Modernization Pilot Program [1]	**1,610**	94	**379**	94	1,558
New Smyrna Beach, Florida[1]	**1,409**	235	**352**	235	1,409
2017 Eastern Shore System Expansion - including interim services [1]	**8,015**	483	**3,577**	483	15,709
Northwest Florida Expansion[1]	**3,485**	—	**1,307**	—	6,500
Western Palm Beach County, Florida Expansion[1]	**54**	—	**54**	—	1,250
Marlin Gas Services	**110**	—	**110**	—	4,475
Ohl propane acquisition (rolled into Sharp)	**—**	—	**—**	—	1,200
Total	**$ 38,910**	$ 17,959	**$ 12,264**	$ 6,937	$ 58,177

[1] Gross margin amounts included in this table have not been adjusted to reflect the impact of the TCJA. Any TCJA-related refunds and/or rate reductions implemented in the Company's regulated businesses were, or will be, offset by lower federal income taxes due to the TCJA.

Ongoing Growth Initiatives

Florida GRIP

GRIP is a natural gas pipe replacement program approved by the Florida Public Service Commission ("PSC"). Since the program's inception in August 2012, we have invested $127.0 million to replace 268 miles of qualifying distribution mains, including $13.3 million and $10.8 million during 2018 and 2017, respectively. GRIP generated additional gross margin of $1.3 million and $346,000 for the year and quarter ended December 31, 2018, respectively, compared to the same periods in 2017. There are approximately 79 remaining miles of main that will be replaced under this program, at an estimated cost of $35.0 million.

Regulatory Proceedings

Eastern Shore Rate Case

Eastern Shore's rate case settlement agreement became final on April 1, 2018, with settlement rates effective January 1, 2018. The final agreement increases Eastern Shore's annual operating income by $6.6 million, representing an estimated $9.8 million in additional margin from base rates, offset by the pass-through of an estimated $3.2 million in lower federal income tax expense for Eastern Shore resulting from the TCJA. For the year ended December 31, 2018, Eastern Shore recognized incremental gross margin of approximately $5.8 million. As of December 31, 2018, Eastern Shore has provided rate reductions to its

customers totaling approximately $3.3 million as a result of the new rates. Annual margin from the new rates in future years is estimated to be $9.8 million.

Florida Electric Reliability/Modernization Pilot Program
In December 2017, the Florida PSC approved a $1.6 million annualized rate increase effective January 2018, for the recovery of a limited number of investments and costs related to reliability, safety and modernization for our Florida electric distribution system. This increase will continue through at least the last billing cycle of December 2019. For the year and quarter ended December 31, 2018, additional margin of $1.5 million and $285,000, respectively, was generated by this program.

Major Projects and Initiatives Currently Underway

New Smyrna Beach, Florida Project
In the fourth quarter of 2017, we commenced construction of a 14-mile natural gas transmission pipeline to serve current and planned customer growth in the New Smyrna Beach service area. The project was partially placed into service at the end of 2017 and was fully placed into service during the fourth quarter of 2018. For the year and quarter ended December 31, 2018, the project generated incremental gross margin of approximately $1.2 million and $117,000 compared to the same periods in 2017. The project is expected to generate $1.4 million in annual gross margin going forward.

2017 Eastern Shore System Expansion Project
From November 2017 to December 2018, Eastern Shore substantially completed the construction of a system expansion that increased its capacity by 26 percent. The first phase of the project was placed into service in December 2017. For the quarter and year ended December 31, 2018, the project generated $3.1 million and $7.5 million, respectively, of incremental gross margin, including margin from interim services, compared to 2017. The project is expected to produce total annual margin of approximately $15.7 million in 2019, $15.8 million from 2020 through 2022, and $13.2 million thereafter.

Northwest Florida Expansion Project
Peninsula Pipeline completed construction of transmission lines, and the Company's Florida natural gas division completed construction of lateral distribution lines, to serve customers in Northwest Florida. The project was placed into service in May 2018, generating gross margin of $1.3 million and $3.5 million for the quarter and year ended December 31, 2018, respectively, and is expected to generate estimated annual gross margin of $6.5 million thereafter.

Western Palm Beach County, Florida Project
Peninsula Pipeline is constructing transmission lines to bring natural gas to our natural gas distribution system in West Palm Beach, Florida. The first phase of this project was placed into service in December 2018 and generated gross margin of $54,000 for the year and quarter ended December 31, 2018. The Company expects to complete this project in phases through early 2020 and estimates gross margin of $1.3 million for 2019 and annual gross margin of approximately $5.4 million, once the project is fully in service.

Marlin Gas Services
In December 2018, the Company acquired certain operating assets of Marlin Gas Transport, Inc., a supplier of mobile compressed natural gas utility and pipeline solutions, and a new subsidiary was created named Marlin Gas Services. The acquisition will enable us to offer solutions to address customer supply interruption scenarios and tailor other alternatives where pipeline supplies are not available. Results generated in 2018 were immaterial given the date of acquisition. The Company estimates that this acquisition will generate gross margin of approximately $4.5 million in 2019, with potential for additional growth in future years.

Ohl Propane Acquisition
In December 2018, Sharp acquired certain propane customers and operating assets of R. F. Ohl Fuel Oil, Inc. ("Ohl"). Ohl provided propane delivery service to approximately 2,500 residential and commercial customers in Pennsylvania, between two of Sharp's existing districts. The acquired customers and assets have been assimilated into Sharp. Results generated in 2018 were immaterial, given the date of acquisition.

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The Company estimates that this acquisition will generate gross margin of approximately $1.2 million in 2019, with potential for additional growth in future years.

Future Projects not included in the Table above

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

Weather and Consumption
The impact of colder temperatures on customer consumption during 2018 contributed $5.0 million in incremental gross margin compared to 2017. While 2018 was colder than 2017, it was still 1.1 percent warmer than normal (average across our service territories). Normal weather during 2018 would have generated $4.0 million in additional gross margin.

For the quarter ended December 31, 2018, warmer weather on the Delmarva Peninsula lowered gross margin by $351,000 compared to the same period in 2017. Normal weather during the fourth quarter would have generated $1.5 million in additional gross margin. The following table summarizes the heating degree-days ("HDD") and cooling degree-days ("CDD") information for the years and quarters ended December 31, 2018 and 2017 and shows variances between actual and "Normal" (10-year average) HDD and CDD for those periods.

HDD and CDD Information

For the Periods Ended December 31,	2018	2017	Variance	Q4 2018	Q4 2017	Variance
Delmarva						
Actual HDD	**4,251**	3,800	451	**1,522**	1,538	(16)
10-Year Average HDD ("Normal")	**4,379**	4,374	5	**1,533**	1,529	4
Variance from Normal	**(128)**	(574)		**(11)**	9	
Florida						
Actual HDD	**780**	533	247	**273**	235	38
10-Year Average HDD ("Normal")	**800**	818	(18)	**267**	263	4
Variance from Normal	**(20)**	(285)		**6**	(28)	
Ohio						
Actual HDD	**5,845**	5,126	719	**2,138**	2,057	81
10-Year Average HDD ("Normal")	**5,823**	5,914	(91)	**2,048**	2,048	—
Variance from Normal	**22**	(788)		**90**	9	
Florida						
Actual CDD	**3,105**	3,013	92	**401**	407	(6)
10-Year Average CDD ("Normal")	**2,889**	2,865	24	**296**	286	10
Variance from Normal	**216**	148		**105**	121	

Note: The Company continually refines and updates its weather calculations. These refinements may result in the annual impact varying from the aggregate of the quarterly variances previously disclosed.

Natural Gas Distribution Customer and Consumption Growth

Customer growth for the Company's natural gas distribution operations generated $3.9 million and $1.1 million in additional gross margin for the year and quarter ended December 31, 2018, respectively, compared to the same periods in 2017. The additional margin was generated from an increase of approximately 3.3 percent in the average number of residential customers served, growth in volumes delivered to commercial and industrial customers on the Delmarva Peninsula and in Florida, and new service initiated to customers in Northwest Florida.

Higher residential and commercial customer consumption increased gross margin by $2.0 million and $501,000 for the year and quarter ended December 31, 2018, respectively, compared to the same periods in 2017.

(in thousands)	Margin Increase	
For the Periods Ended December 31,	**2018**	**Q4 2018**
Customer growth:		
Residential	$ 1,604	$ 433
Commercial and industrial, excluding new service in Northwest Florida	1,322	296
New service in Northwest Florida	987	336
Total customer growth	3,913	1,065
Volume growth:		
Residential	655	207
Commercial and industrial	1,522	279
Other - including unbilled revenue	(179)	15
Total volume growth	1,998	501
Total natural gas distribution growth	$ 5,911	$ 1,566

Propane Operations

The Company's Florida and Mid-Atlantic propane distribution operations continue to pursue a multi-pronged growth plan, which includes: targeting retail and wholesale customer growth in existing markets, both organically as well as through acquisitions; incremental growth from recent and planned start-ups in new markets; targeting new community gas systems in high growth areas; further build-out of the Company's propane vehicular platform through AutoGas fueling stations; and optimization of its supply portfolio to generate incremental margin opportunities. Our propane operations and AutoGas segment install and support propane vehicle conversion systems for vehicle fleets, including converting fleets to bi-fuel propane-powered engines and providing on-site fueling infrastructure.

These operations generated $4.9 million and $68,000 in incremental margin for the year and quarter ended December 31, 2018, respectively, compared to the same periods in 2017. For the year ended December 31, 2018, $2.2 million of the margin increase reflected the impact of colder temperatures. The balance of the gross margin increase for the year reflected the impact of the growth strategies discussed above, including generating approximately a four percent increase in customers. Supply management initiatives have also increased retail propane margins from many customer classes and margin from wholesale propane sales.

PESCO

PESCO's gross margin for the year and quarter ended December 31, 2018 increased by $4.4 million and $5.6 million, respectively, compared to the same periods in 2017. The following table summarizes the changes in PESCO'S year-over-year margin for the year and quarter ended December 31, 2018:

For the periods ended December 31,	**2018**	**Q4 2018**
(in thousands)		
Net impact of PESCO's MTM activity	$ 10,423	$ 5,216
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [1]	(3,284)	—
Loss for the Mid-Atlantic retail portfolio caused by pipeline capacity constraints in January and warm weather in February 2018 [1]	(2,261)	—
Other margin for PESCO operations (net)	(489)	409
Total Change in Gross Margin for PESCO in 2018	$ 4,389	5,625

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

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

PESCO generated an operating loss of $200,000 for the quarter ended December 31, 2018, compared to a loss of $5.3 million during the prior year period. The improvement in quarter-over-quarter results reflects the absence of the MTM loss recorded in the fourth quarter of 2017.

Xeron

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

Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Income (Unaudited)
For the Periods Ended December 31, 2018 and 2017

(in thousands, except shares and per share data)

	Year Ended		Fourth Quarter	
	2018	2017	2018	2017
Operating Revenues				
Regulated Energy	$ 345,281	$ 326,310	$ 92,614	$ 87,957
Unregulated Energy	420,617	324,595	122,862	104,133
Other businesses and eliminations	(48,409)	(33,322)	(14,286)	(11,687)
Total Operating Revenues	717,489	617,583	201,190	180,403
Operating Expenses				
Regulated energy cost of sales	121,828	118,769	32,085	31,563
Unregulated energy and other cost of sales	288,913	219,145	84,034	73,819
Operations	138,441	125,994	36,637	34,218
Maintenance	14,387	12,701	3,968	3,331
Gain from a settlement	(130)	(130)	—	—
Depreciation and amortization	40,802	36,599	10,627	9,331
Other taxes	18,628	17,085	4,909	4,513
Total operating expenses	622,869	530,163	172,260	156,775
Operating Income	94,620	87,420	28,930	23,628
Other expense, net	(615)	(2,342)	(410)	(486)
Interest charges	16,431	12,645	4,456	3,513
Income Before Income Taxes	77,574	72,433	24,064	19,629
Income taxes	20,994	14,309	6,263	(6,472)
Net Income	$ 56,580	$ 58,124	$ 17,801	$ 26,101
Weighted Average Common Shares Outstanding:				
Basic	16,369,616	16,336,789	16,378,545	16,344,442
Diluted	16,419,870	16,383,352	16,430,594	16,397,332
Earnings Per Share of Common Stock:				
Basic	$ 3.46	$ 3.56	$ 1.09	$ 1.60
Diluted	$ 3.45	$ 3.55	$ 1.08	$ 1.59

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Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets (Unaudited)

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets (Unaudited)

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

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Chesapeake Utilities Corporation and Subsidiaries
Distribution Utility Statistical Data (Unaudited)

	For the Three Months Ended December 31, 2018				For the Three Months Ended December 31, 2017			
	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution
Operating Revenues *(in thousands)*								
Residential	$ 15,647	$ 1,313	$ 5,846	$ 9,450	$ 14,854	$ 1,435	$ 8,157	$ 10,166
Commercial	8,260	1,566	6,491	8,711	7,860	1,493	7,170	9,951
Industrial	2,274	3,117	5,995	411	2,236	1,676	5,921	1,609
Other (1)	5,426	883	3,901	298	5,090	1,039	(444)	(1,640)
Total Operating Revenues	$ 31,607	$ 6,879	$ 22,233	$ 18,870	$ 30,040	$ 5,643	$ 20,804	$ 20,086
Volumes (in Dts for natural gas and KWHs for electric)								
Residential	962,407	90,091	327,226	65,844	792,602	86,682	327,815	66,998
Commercial	947,924	1,192,733	417,254	69,464	829,713	1,165,579	436,272	74,689
Industrial	1,518,671	6,577,922	1,220,219	3,350	1,375,672	3,042,088	1,171,381	15,130
Other	23,313	—	919,192	1,686	29,142	—	593,768	1,885
Total	3,452,315	7,860,746	2,883,891	140,344	3,027,129	4,294,349	2,529,236	158,702
Average Customers								
Residential	72,219	16,703	56,181	24,573	69,532	15,967	54,704	24,648
Commercial	6,992	1,550	3,893	7,508	6,848	1,435	3,962	7,468
Industrial	162	17	2,380	2	155	80	2,186	2
Other	4	—	12		3	—	10	
Total	79,377	18,270	62,466	32,083	76,538	17,482	60,862	32,118

	For the Year Ended December 31, 2018				For the Year Ended December 31, 2017			
	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution
Operating Revenues *(in thousands)*								
Residential	$ 70,466	$ 5,086	$ 30,334	$ 44,788	$ 57,365	$ 5,600	$ 33,103	$ 44,082
Commercial	36,916	6,236	26,993	39,442	31,585	5,756	30,283	41,141
Industrial	8,289	10,911	22,296	1,543	7,619	6,535	21,647	3,561
Other (1)	928	3,108	1,494	(5,970)	3,504	3,858	(5,353)	(5,918)
Total Operating Revenues	$ 116,599	$ 25,341	$ 81,117	$ 79,803	$ 100,073	$ 21,749	$ 79,680	$ 82,866
Volumes (in Dts for natural gas and KWHs for electric)								
Residential	4,142,567	369,067	1,393,785	307,269	3,368,603	340,570	1,350,413	291,510
Commercial	3,792,220	4,719,725	1,722,081	302,687	3,274,975	5,156,823	1,863,147	304,235
Industrial	5,549,387	19,858,336	4,900,998	15,160	5,125,633	11,561,309	4,543,775	27,380
Other	80,254	—	2,338,815	7,402	95,415	—	1,875,761	7,511
Total	13,564,428	24,947,128	10,355,679	632,518	11,864,626	17,058,702	9,633,096	630,636
Average Customers								
Residential	71,322	16,450	55,701	24,686	68,699	15,796	54,410	24,574
Commercial	6,979	1,519	3,915	7,497	6,845	1,421	4,054	7,450
Industrial	157	16	2,312	2	147	79	2,078	2
Other	5	—	11	—	5	—	10	
Total	78,463	17,985	61,939	32,185	75,696	17,296	60,552	32,026

(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.

Exhibit C-1 "Annual Reports"
Exhibit C-2 "SEC Filings"

FOR IMMEDIATE RELEASE
May 8, 2019
NYSE Symbol: CPK

CHESAPEAKE UTILITIES CORPORATION REPORTS FIRST QUARTER 2019 RESULTS

- **Chesapeake Utilities delivers strong financial and operational results in the first quarter**
- **GAAP net income increased by 6.7 percent to $28.7 million or $1.74 per share* compared to $1.64 per share for the first quarter of 2018**
- **Adjusted (Non-GAAP)** earnings increased to $1.68 per share from $1.40 per share, representing 20.0 percent growth**
- **Gross margin** increased $10.1 million, or 11.1 percent**
- **Recently constructed pipeline projects contributed $4.3 million in gross margin and are expected to generate $24.0 million in gross margin for the year**
- **December 2018 acquisitions of Marlin and Ohl contributed $2.8 million in gross margin and $1.6 million in operating income for the quarter**

Dover, Delaware — Chesapeake Utilities Corporation (NYSE: CPK) ("Chesapeake Utilities" or the "Company") today announced first quarter financial results. The Company's net income for the quarter ended March 31, 2019 was $28.7 million, compared to $26.9 million for the same quarter of 2018. Earnings per share ("EPS") for the quarter ended March 31, 2019 were $1.74, compared to $1.64 per share for the same quarter of 2018.

The higher earnings reflected the positive impact of recently completed and ongoing pipeline expansion projects, accretion from the Marlin Gas Transport, Inc. ("Marlin Gas Transport") and R. F. Ohl Fuel Oil, Inc. ("Ohl") acquisitions, organic growth in the natural gas distribution operations and higher propane retail margins per gallon. Earnings also increased as a result of an order from the Florida Public Service Commission ("PSC") authorizing the Company to retain a portion of the tax savings associated with lower federal tax rates resulting from the United States Tax Cuts and Jobs Act ("TCJA") for certain of the Company's natural gas distribution operations. These increases were partially offset by a $2.5 million margin decrease associated with lower energy consumption due to warmer weather in Florida and the absence of the "Bomb Cyclone" weather impact that sharply increased first quarter 2018 consumption within the Delmarva propane and natural gas distribution operations. A detailed discussion of operating results begins on page 3.

"2019 is off to a great start, as demonstrated by our strong financial results and continued growth across our business segments. In particular, our performance reflects increased contributions from natural gas service expansions, the Marlin Gas Transport and Ohl acquisitions, higher retail propane margins and the favorable outcomes of several regulatory initiatives. Our employees' ingenuity, dedication and commitment to our growth strategy propelled our success during the quarter," stated Jeff Householder, President and Chief Executive Officer of Chesapeake Utilities Corporation. "We are excited about the future growth potential from these recent acquisitions and expansions. We also continue to evaluate additional attractive growth opportunities, with the goal of transforming such opportunities into new investments that generate increased earnings growth and value for our shareholders."

Significant Items Impacting Earnings

Results for the three months ended March 31, 2019 and 2018 were impacted by the following significant items:

For the Three Months Ended March 31,	**2019**		**2018**	
(in thousands, except per share data)	**Net Income**	**EPS**	**Net Income**	**EPS**
Reported (GAAP) Earnings	**$ 28,664**	**$ 1.74**	**$ 26,855**	**$ 1.64**
Change in unrealized mark-to-market ("MTM") activity	80	—	(4,008)	(0.24)
2018 portion of the retained tax savings for certain Florida natural gas distribution operations associated with the TCJA income tax rate reduction	(990)	(0.06)	—	—
Adjusted (Non-GAAP) Earnings**	**$ 27,754**	**$ 1.68**	**$ 22,847**	**$ 1.40**

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

***This press release includes references to non-Generally Accepted Accounting Principles ("GAAP") financial measures, including gross margin, adjusted earnings and Adjusted EPS. A "non-GAAP financial measure" is generally defined as a numerical measure of a company's historical or future performance that includes or excludes amounts, or that is subject to adjustments, so as to be different from the most directly comparable measure calculated or presented in accordance with GAAP. Our management believes certain non-GAAP financial measures, when considered together with GAAP financial measures, provide information that is useful to investors in understanding period-over-period operating results separate and apart from items that may, or could, have a disproportionately positive or negative impact on results in any particular period.*

The Company calculates "gross margin" by deducting the cost of sales from operating revenue. Cost of sales includes the purchased fuel cost for natural gas, electricity and propane, and the cost of labor spent on direct revenue-producing activities and excludes depreciation, amortization and accretion. Other companies may calculate gross margin in a different manner. Gross margin should not be considered an alternative to operating income or net income, both of which are determined in accordance with GAAP. The Company believes 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 the Company under its allowed rates for regulated operations and under its competitive pricing structures for unregulated businesses. The Company's management uses gross margin in measuring its business units' performance. The Company calculates "adjusted earnings" by adjusting reported (GAAP) earnings to exclude the impact of certain significant non-cash items, including the impact

of unrealized MTM gains (losses) and one-time charges, such as severance charges, and any prior year tax savings retained by our regulated businesses as a result of current year regulatory authorizations. The Company calculates "adjusted EPS" by dividing adjusted earnings by the weighted average common shares outstanding.

Operating Results for the Quarter Ended March 31, 2019 and 2018

Consolidated Results

(in thousands)	Three Months Ended March 31, 2019	2018	Change	Percent Change
Gross margin	**$ 101,397**	$ 91,299	$ 10,098	11.1%
Depreciation, amortization and property taxes	**15,504**	13,697	1,807	13.2%
Other operating expenses	**41,900**	37,196	4,704	12.6%
Operating income	**$ 43,993**	$ 40,406	$ 3,587	8.9%

Operating income during the first quarter of 2019 increased by $3.6 million, or 8.9 percent, compared to the same period in 2018. The increase in operating income reflects continued strong growth across the Company, with contributions from existing businesses, recent expansion investments, regulatory initiatives, the successful integration and margin generated from Ohl and the particularly strong performance of Marlin Gas Services, LLC ("Marlin"), the Company's newly created subsidiary that acquired certain operating assets of Marlin Gas Transport.

Regulated Energy Segment

(in thousands)	Three Months Ended March 31, 2019	2018	Change	Percent Change
Gross margin	**$ 67,102**	$ 61,162	$ 5,940	9.7%
Depreciation, amortization and property taxes	**12,531**	11,156	1,375	12.3%
Other operating expenses	**24,830**	23,295	1,535	6.6%
Operating income	**$ 29,741**	$ 26,711	$ 3,030	11.3%

Operating income for the Regulated Energy segment increased by $3.0 million, or 11.3 percent, in the first quarter of 2019 compared to the same period in 2018. This increase was driven by a $5.9 million increase in gross margin, offset by $1.4 million in higher depreciation, amortization and property taxes and $1.5 million in higher other operating expenses associated with the margin growth. The increase in operating income reflects continued growth in the natural gas operations and expansion projects completed by Peninsula Pipeline Company, Inc. ("Peninsula Pipeline") and Eastern Shore Natural Gas Company ("Eastern Shore"), the Company's intrastate and interstate transmission subsidiaries, respectively. Further, during the quarter, the Florida PSC issued a final order allowing the Company to retain tax savings associated with lower federal tax rates for certain of the Company's natural gas distribution operations. As a result, $1.3 million in reserves for customer refunds recorded in 2018, were reversed in 2019. Additionally, growth in the business and accrual timing resulted in an increase in incentive compensation expense of $653,000 in the first quarter 2019 compared to the same period in 2018.

The key components of the increase in gross margin are shown below:

(in thousands)	Margin Impact
Eastern Shore and Peninsula Pipeline service expansions	$ 4,266
Natural gas distribution - customer growth (excluding service expansions)	1,451
2018 retained tax savings for certain Florida natural gas distribution operations	1,321
Impact of weather on customer consumption (primarily in Florida)	(1,093)
Natural gas distribution - change in customer consumption (non-weather)	(485)
Conversion of Sandpiper Energy Inc. ("Sandpiper") customers to natural gas	382
Florida Gas Reliability and Infrastructure Program ("GRIP")	223
Other immaterial variances	(125)
Quarter-over-quarter increase in gross margin	**$ 5,940**

The major components of the increase in other operating expenses are as follows:

(in thousands)	Other Operating Expenses
Depreciation, amortization and property taxes primarily associated with recent growth projects	$ 1,375
Incentive compensation costs (based on timing and period-over-period results)	653
Outside services, facilities and maintenance costs	(609)
Payroll expense (increased staffing and annual salary increases)	608
Benefits and other employee-related expenses[1]	551
Other immaterial variances	332
Quarter-over-quarter increase in other operating expenses	**$ 2,910**

[1] Since the Company self-insures for healthcare costs, benefits costs fluctuate depending upon filed claims.

Unregulated Energy Segment

	Three Months Ended March 31,			
(in thousands)	2019	2018	Change	Percent Change
Gross margin	**$ 34,402**	$ 30,301	$ 4,101	13.5%
Depreciation, amortization and property taxes	**2,939**	2,505	434	17.3%
Other operating expenses	**16,336**	14,112	2,224	15.8%
Operating income	**$ 15,127**	$ 13,684	$ 1,443	10.5%

Given the impact of MTM activity on the first quarter 2018 results of Peninsula Energy Services Company, Inc. ("PESCO"), the Company continues to present PESCO's results separate from the rest of the Unregulated Energy segment:

Unregulated Energy Segment, excluding PESCO

(in thousands)	Three Months Ended March 31, 2019	2018	Change	Percent Change
Gross margin	$ 32,542	$ 29,126	$ 3,416	11.7%
Depreciation, amortization and property taxes	2,792	2,357	435	18.5%
Other operating expenses	14,113	12,321	1,792	14.5%
Operating income	$ 15,637	$ 14,448	$ 1,189	8.2%

Excluding PESCO, operating income for the Unregulated Energy segment increased by $1.2 million for the three months ended March 31, 2019, compared to the same period in 2018. The increased operating income was driven by a $3.4 million increase in gross margin, partially offset by $1.8 million in higher operating expenses and $435,000 in higher depreciation and taxes.

The major components of the $3.4 million increase in gross margin are shown below:

(in thousands)	Margin Impact
Marlin (acquired assets of Marlin Gas Transport in December 2018)	$ 2,329
Propane Operations	
Decrease in weather-related customer consumption due to the absence of the 2018 Bomb Cyclone	(1,307)
Increased retail margins per gallon	1,259
Customer growth, increased sales volumes (non-weather-related) and other factors	482
Ohl acquisition (assets acquired in December 2018)	476
Lower wholesale propane margins and sales	(453)
Aspire Energy of Ohio, LLC ("Aspire Energy")	
Rate increases	779
Increased customer consumption	397
Other immaterial variances	(546)
Quarter-over-quarter increase in gross margin	$ 3,416

The major components of the increase in other operating expenses are as follows:

(in thousands)	Other Operating Expenses
Operating expenses associated with operating Marlin and Ohl (Asset acquisitions in December 2018	$ 1,157
Incentive compensation costs (based on timing and period-over-period results)	466
Outside services and facilities maintenance costs	286
Depreciation, asset removal and property tax costs due to new capital investments	187
Benefits and other employee-related expenses[1]	133
Other immaterial variances	(2)
Quarter-over-quarter increase in other operating expenses	$ 2,227

[1] Since the Company self-insures for healthcare costs, benefits costs fluctuate depending upon filed claims.

PESCO

(in thousands)	Three Months Ended March 31, 2019	2018	Change	Percent Change
Gross margin	$ 1,860	$ 1,175	$ 685	58.3 %
Depreciation, amortization and property taxes	147	148	(1)	(0.7)%
Other operating expenses	2,223	1,791	432	24.1 %
Operating loss	$ (510)	$ (764)	$ 254	33.2 %

For the three months ended March 31, 2019, PESCO's gross margin was higher by $685,000 compared to the same period in 2018. Operating expenses increased by $432,000, reflecting increased staffing, infrastructure and risk management systems necessary to support growth. Overall, PESCO's quarter-over-quarter performance improved by $254,000.

Matters included in this release may include forward-looking statements that involve risks and uncertainties. Actual results may differ materially from those in the forward-looking statements. Please refer to the Safe Harbor for Forward-Looking Statements in the Company's 2018 Annual Report on Form 10-K for further information on the risks and uncertainties related to the Company's forward-looking statements.

Conference Call

Chesapeake Utilities will host a conference call on Friday, May 10, 2019 at 10:30 a.m. Eastern Time to discuss the Company's financial results for the three months ended March 31, 2019. To participate in this call, dial 855.801.6270 and reference Chesapeake Utilities' 2019 First Quarter Results Conference Call. To access the replay recording of this call, the accompanying transcript, and other pertinent quarterly information, use the link CPK - Conference Call Audio Replay, or visit the Investors/Events and Presentations section of Company's website at www.chpk.com.

About Chesapeake Utilities Corporation

Chesapeake Utilities is a diversified energy company engaged in natural gas distribution, transmission and marketing; electricity generation and distribution; propane gas distribution; and other businesses. Information about Chesapeake Utilities and its family of businesses is available at http://www.chpk.com or through its Investor Relations (IR) App.

Please note that Chesapeake Utilities Corporation is not affiliated with Chesapeake Energy, an oil and natural gas exploration company headquartered in Oklahoma City, Oklahoma.

For more information, contact:

Beth W. Cooper
Executive Vice President, Chief Financial Officer and Assistant Corporate Secretary
302.734.6799

Financial Summary

(in thousands, except per share data)

	Three Months Ended March 31,	
	2019	**2018**
Gross Margin		
Regulated Energy segment	**$ 67,102**	$ 61,162
Unregulated Energy segment	**34,402**	30,301
Other businesses and eliminations	**(107)**	(164)
Total Gross Margin	**$ 101,397**	$ 91,299
Operating Income		
Regulated Energy segment	**$ 29,741**	$ 26,711
Unregulated Energy segment	**15,127**	13,684
Other businesses and eliminations	**(875)**	11
Total Operating Income	**43,993**	40,406
Other income (expense), net	**(45)**	68
Interest Charges	**5,710**	3,664
Pre-tax Income	**38,238**	36,810
Income Taxes	**9,574**	9,955
Net Income	**$ 28,664**	$ 26,855
Earnings Per Share of Common Stock		
Basic	**$ 1.75**	$ 1.64
Diluted	**$ 1.74**	$ 1.64

Financial Summary Highlights

Key variances, between the three months ended March 31, 2018 and 2019, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
First Quarter of 2018 Reported Results	**$ 36,810**	**$ 26,855**	**$ 1.64**
Adjusting for Unusual Items:			
Net impact of PESCO's MTM activity	(5,591)	(4,088)	(0.24)
Impact of weather on customer consumption	(2,523)	(1,891)	(0.12)
2018 retained tax savings for certain Florida natural gas operations	1,321	990	0.06
	(6,793)	(4,989)	(0.30)
Increased (Decreased) Gross Margins:			
Absence of the 2018 Bomb Cyclone and capacity constraints cost for PESCO	5,545	4,157	0.25
Eastern Shore and Peninsula Pipeline service expansions*	4,266	3,198	0.19
Margin contribution from Marlin and Ohl (assets acquired in December 2018)*	2,805	2,103	0.13
Natural gas distribution - customer growth (excluding service expansions)	1,451	1,088	0.06
Higher propane retail margins per gallon	1,259	944	0.06
Unregulated Energy customers' consumption growth	879	659	0.04
Aspire Energy rate increases	779	584	0.04
Other margin for PESCO operations	731	548	0.03
Natural gas distribution - change in customer consumption (non-weather)	(485)	(364)	(0.02)
Lower wholesale propane margins and sales	(453)	(340)	(0.02)
Conversion of Sandpiper customers to natural gas	382	287	0.02
Florida GRIP*	223	167	0.01
	17,382	13,031	0.79
Decreased (Increased) Other Operating Expenses:			
Depreciation, asset removal and property tax costs due to growth investments	(1,560)	(1,169)	(0.07)
Incentive compensation costs (based on timing and period-over-period results)	(1,931)	(1,448)	(0.09)
Operating expenses for Marlin and Ohl (assets acquired in December 2018)	(1,157)	(867)	(0.05)
Benefits and other employee-related expenses	(732)	(549)	(0.03)
Payroll expense (increased staffing and annual salary increases)	(673)	(504)	(0.03)
Operating expenses to support growth for PESCO	(431)	(323)	(0.02)
	(6,484)	(4,860)	(0.29)
Interest charges	(2,046)	(1,534)	(0.09)
Change in effective tax rate	—	768	0.05
Net other changes	(631)	(607)	(0.06)
	(2,677)	(1,373)	(0.10)
First Quarter of 2019 Reported Results	**$ 38,238**	**$ 28,664**	**$ 1.74**

***See the Major Projects and Initiatives table later in this press release.**

Recently Completed and Ongoing Major Projects and Initiatives

The Company constantly pursues and develops additional projects and initiatives in order to further increase shareholder value and serve existing and new customers. The following represent the major projects/initiatives recently completed and currently underway. In the future, the Company will add new projects and initiatives to this table once they are substantially final.

	Gross Margin for the Period				
	Three Months Ended		Year Ended	Estimate for	
Project/Initiative	March 31,		December 31,	Fiscal	
in thousands	2019	2018	2018	2019	2020
Florida GRIP [1]	$ 3,565	$ 3,342	$ 13,323	$ 14,204	$ 15,565
2017 Eastern Shore System Expansion Project - including interim services	4,800	2,263	9,238	16,183	15,799
Tax benefit retained by certain Florida entities[2]	2,115	—	—	3,199	1,879
Northwest Florida Expansion	1,307	—	3,485	6,500	6,500
Western Palm Beach County, Florida Expansion	161	—	54	605	4,711
Marlin	2,329	—	110	5,100	6,000
Ohl propane acquisition (rolled into Sharp)	476	—	—	1,200	1,236
Del-Mar Energy Pathway Project - including interim services	165	—	—	725	3,039
Total	$ 14,918	$ 5,605	$ 26,210	$ 47,716	$ 54,729

(1) All periods shown have been adjusted to reflect the lower customer rates as a result of the TCJA. Lower customer rates are offset by the corresponding decrease in federal income tax expense and have no negative impact on net income.

(2) The amount disclosed for the first quarter of 2019 includes tax savings of $1.3 million for the year ended December 31, 2018, due to an order by the Florida PSC allowing reversal of a TCJA refund reserve, recorded in 2018, which increased gross margin for the quarter by that amount.

GRIP

Florida GRIP is a natural gas pipe replacement program approved by the Florida PSC that allows automatic recovery, through rates, of costs associated with the replacement of mains and services. Since the program's inception in August 2012, the Company has invested $131.4 million of capital expenditures to replace 268 miles of qualifying distribution mains, including $4.1 million during the first three months of 2019. GRIP generated additional gross margin of $223,000 for the three months ended March 31, 2019 compared to the same period in 2018.

Major Projects and Initiatives Currently Underway

2017 Eastern Shore System Expansion Project

Eastern Shore has substantially completed the construction of a system expansion project which increased its capacity by 26 percent. The few remaining segments are expected to be placed into service in various phases during the second quarter of 2019. The project generated $2.5 million in incremental gross margin during the three months ended March 31, 2019 compared to the same period in 2018. The project is expected to produce gross margin of approximately $16.2 million this year, $15.8 million annually from 2020 through 2022, and $13.2 million annually thereafter.

Northwest Florida Expansion Project

In May 2018, Peninsula Pipeline completed construction of transmission lines, and the Company's Florida natural gas division completed construction of lateral distribution lines, to serve customers in Northwest Florida. The project generated incremental gross margin of $1.3 million for the three months ended March 31, 2019. The estimated annual gross margin from this project for 2019 and future years is $6.5 million, with the opportunity for additional margin as the remaining capacity is sold.

Western Palm Beach County Belvedere, Florida Project

Peninsula Pipeline is constructing four transmission lines to bring natural gas to the Company's distribution system in West Palm Beach, Florida. The first phase of this project was placed into service in December 2018 and generated $161,000 in additional gross margin for the three months ended March 31, 2019. The Company expects to complete the remainder of the project in phases through early 2020 and estimates that it will generate gross margin of $605,000 in 2019 and approximately $4.7 million in future years once fully in service.

Marlin

In December 2018, the Company acquired certain operating assets of Marlin Gas Transport, a supplier of mobile compressed natural gas utility and pipeline solutions, and created Marlin, a new subsidiary which offers compressed natural gas solutions to supply interruption scenarios and provides other unique applications where pipeline supplies are unavailable or inadequate to meet customer requirements. Marlin generated $2.3 million of gross margin for the three months ended March 31, 2019. Based on Marlin's strong first quarter results, we have increased our 2019 full year margin estimate for this business from $4.5 million to $5.1 million and established our preliminary 2020 estimate for gross margin of $6.0 million.

Ohl Propane Acquisition

In December 2018, Sharp acquired certain propane customers and operating assets of Ohl. Located between two of Sharp's existing districts, Ohl provided propane distribution service to approximately 2,500 residential and commercial customers in Pennsylvania. The customers and assets acquired from Ohl have been assimilated into Sharp. The operations acquired from Ohl generated $476,000 of incremental gross margin for the three months ended March 31, 2019. The Company estimates that this acquisition will generate additional gross margin of approximately $1.2 million for Sharp in 2019, with the potential for additional growth in future years.

Del-Mar Energy Pathway Project

In September 2018, Eastern Shore filed for FERC authorization to construct the Del-Mar Energy Pathway project to provide an additional 14,300 dekatherms per day of capacity to four customers. The benefits of this project include additional natural gas transmission pipeline infrastructure in eastern Sussex County, Delaware, and the initial extension of Eastern Shore's pipeline system into Somerset County, Maryland. Interim services in advance of this project generated $165,000 for the three months ended March 31, 2019. The estimated annual gross margin from this project is approximately $725,000 in 2019, $3.0 million in 2020, $4.6 million in 2021 and $5.1 million annually thereafter. Eastern Shore anticipates that this project will be fully in-service by mid-2021, contingent upon FERC granting its authorization for the project by August 2019.

Regulatory Initiatives

Florida Tax Savings Related to TCJA

In the first quarter of 2019, the Florida PSC issued orders authorizing certain of the Company's natural gas distribution operations to retain a portion of the tax savings associated with the lower federal tax rates resulting from the TCJA. The Company expects these savings to continue in future years.

Other major factors influencing gross margin

Weather and Consumption

Weather conditions accounted for a $2.5 million decrease in gross margin during the first quarter of 2019, compared to the same period in 2018. While period-over-period heating degree-days ("HDD") were essentially flat on the Delmarva Peninsula, extreme conditions during the 2018 "Bomb Cyclone" drove weather-related consumption in the first quarter of 2018 compared to the same period in 2019. This decrease in consumption accounted for $1.1 million in lower first quarter 2019 gross margin for the propane operations and $310,000 for the natural gas distribution operations. Weather in Florida was approximately 26 percent warmer in the first quarter of 2019, compared to the same period in 2018, and reduced consumption by propane, electric and natural gas distribution customers which resulted in decreased margin of

approximately $951,000. The following table summarizes HDD and cooling degree day ("CDD") variances from the 10-year average HDD/CDD ("Normal") for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31,		
	2019	2018	Variance
Delmarva			
Actual HDD	**2,322**	2,295	27
10-Year Average HDD ("Normal")	**2,362**	2,354	8
Variance from Normal	**(40)**	(59)	
Florida			
Actual HDD	**361**	490	(129)
10-Year Average HDD ("Normal")	**518**	517	1
Variance from Normal	**(157)**	(27)	
Ohio			
Actual HDD	**2,996**	2,991	5
10-Year Average HDD ("Normal")	**3,045**	3,069	(24)
Variance from Normal	**(49)**	(78)	
Florida			
Actual CDD	**134**	139	(5)
10-Year Average CDD ("Normal")	**97**	89	8
Variance from Normal	**37**	50	

Natural Gas Distribution Margin Growth

New customer growth in the Company's natural gas distribution operations generated $1.5 million of additional margin, which was partially offset by $485,000 in lower margin due to fewer volumes sold to commercial and industrial customers in Florida and at Sandpiper. The details for the three months ended March 31, 2019, are provided in the following table:

(in thousands)	Three Months Ended March 31, 2019
Customer Growth:	
Residential	$ 637
Commercial and industrial, excluding new service in Northwest Florida	529
New service in Northwest Florida	285
Total Customer Growth	1,451
Non-Weather Change in Customer Consumption:	
Residential	(89)
Commercial and industrial	(396)
Total Decline in Customer Consumption	(485)
Total (or net) Increase in Natural Gas Distribution Margin	$ 966

The additional margin from new customers reflects an increase of approximately 3.9 percent in the average number of residential customers served on the Delmarva Peninsula, approximately 3.2 percent growth in residential customers served in Florida, new service to customers in Northwest Florida, as well as an increase in the number of commercial and industrial customers served.

Propane Operations

Gross margin generated by our propane operations increased by $305,000 during the three months ended March 31, 2019, compared to the same period in 2018. The following table summarizes the year-over year changes in gross margin for the propane business for the quarter ended March 31, 2019:

	Three Months Ended March 31, 2019
(in thousands)	
Decrease in customer consumption due to warmer weather	$ (1,307)
Increased retail margins per gallon	1,259
Customer growth, increased sales volumes (non-weather-related) and other factors	482
Ohl acquisition (assets acquired in December 2018)	476
Lower wholesale propane margins and sales	(453)
Other	(152)
2019 Change in gross margin by our propane operations	**$ 305**

Aspire Energy

Gross margin generated by Aspire Energy increased by $796,000 during the three months ended March 31, 2019, compared to the same period in 2018. The increase reflects $779,000 of rate increases and $397,000 of consumption growth, which was offset by a $380,000 decrease in gross margin due to various factors.

PESCO

PESCO's gross margin for the three months ended March 31, 2019 was higher by $685,000, compared to the same period in 2018. The following table summarizes the changes in PESCO'S year-over-year margin for the three months ended March 31, 2019:

	Three Months Ended March 31, 2019
(in thousands)	
Net impact of PESCO's MTM activity	$ (5,591)
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [1]	3,284
Mid-Atlantic retail portfolio loss due to pipeline capacity constraints in the first quarter of 2018 [1]	2,261
Other margin for PESCO operations (net)	731
2019 Change in PESCO gross margin	**$ 685**

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

Capital Investment Growth and Financing

Capital expenditures totaled $33.8 million for the three months ended March 31, 2019. The following table shows the 2019 capital expenditure budget of $168.2 million by segment and by business line:

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

The capital expenditure projection is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts.

Impact of Hurricane Michael

In October 2018, Hurricane Michael passed through Florida Public Utilities Company's ("FPU") electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure, resulting in 100 percent of its Northwest Florida customers losing electrical service. FPU exerted extraordinary hurricane restoration efforts and restored service to those customers who were able to accept it. Through March 31, 2019, FPU has spent approximately $65.0 million to restore service, which was recorded as new plant and equipment or charged against FPU's accumulated depreciation and storm reserve. The Company is in the process of preparing the necessary regulatory filings to seek recovery of the costs incurred. In conjunction with the hurricane-related expenditures, the Company executed two 13-month unsecured term loans as temporary financing, each in the amount of $30.0 million. The interest cost associated with these loans is LIBOR plus 75 basis points. One of the term loans was executed in December 2018, and the other was executed in January 2019. The storm did not have a material impact on the margin from these operations, as services were restored to a majority of the Company's customers. Pending the outcome of the regulatory filings associated with the storm, the Company's results for the first quarter included higher interest expense of $435,000, or $326,000 on an after-tax basis ($0.02 per share) associated with the intermediate term loans discussed above.

The Company's target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. The Company's equity to total capitalization ratio, including short term borrowings, was 46 percent as of March 31, 2019. Excluding the funds expended for Hurricane Michael restoration activities, the Company's equity to total capitalization ratio, including short-term borrowings, would have been approximately 49 percent. The Company seeks to align permanent financing with the in-service dates of its capital projects. The Company may utilize more temporary short-term debt, when the financing cost is attractive, as a bridge to the permanent long-term financing.

Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Income (Unaudited)

(in thousands, except shares and per share data)

	Three Months Ended March 31,	
	2019	2018
Operating Revenues		
Regulated Energy	$ 103,618	$ 109,393
Unregulated Energy and other	123,998	129,963
Total Operating Revenues	227,616	239,356
Operating Expenses		
Regulated Energy cost of sales	36,516	48,231
Unregulated Energy and other cost of sales	89,703	99,826
Operations	37,144	32,702
Maintenance	3,681	3,593
Depreciation and amortization	11,074	9,704
Other taxes	5,505	4,894
Total operating expenses	183,623	198,950
Operating Income	43,993	40,406
Other income (expense), net	(45)	68
Interest charges	5,710	3,664
Income Before Income Taxes	38,238	36,810
Income taxes	9,574	9,955
Net Income	$ 28,664	$ 26,855
Weighted Average Common Shares Outstanding:		
Basic	16,384,927	16,351,338
Diluted	16,432,852	16,402,985
Earnings Per Share of Common Stock:		
Basic	$ 1.75	$ 1.64
Diluted	$ 1.74	$ 1.64

Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Balance Sheets (Unaudited)

Assets	March 31, 2019	December 31, 2018
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	$ 1,346,221	$ 1,297,416
Unregulated Energy	241,126	237,682
Other businesses and eliminations	30,282	34,585
Total property, plant and equipment	1,617,629	1,569,683
Less: Accumulated depreciation and amortization	(312,949)	(294,295)
Plus: Construction work in progress	90,453	108,584
Net property, plant and equipment	1,395,133	1,383,972
Current Assets		
Cash and cash equivalents	7,975	6,089
Trade and other receivables (less allowance for uncollectible accounts of $1,054 and $1,108, respectively)	74,098	85,404
Accrued revenue	20,747	27,499
Propane inventory, at average cost	6,865	9,791
Other inventory, at average cost	8,122	7,127
Regulatory assets	7,913	4,796
Storage gas prepayments	1,327	6,603
Income taxes receivable	9,059	15,300
Prepaid expenses	7,192	10,079
Derivative assets, at fair value	9,221	13,165
Other current assets	1,121	5,684
Total current assets	153,640	191,537
Deferred Charges and Other Assets		
Goodwill	25,785	25,837
Other intangible assets, net	5,909	6,207
Investments, at fair value	7,509	6,711
Operating lease right-of-use assets [(1)]	12,523	—
Regulatory assets	77,101	72,422
Other assets	5,197	6,985
Total deferred charges and other assets	134,024	118,162
Total Assets	$ 1,682,797	$ 1,693,671

[(1)] *During the first quarter of 2019, the Company adopted a new lease accounting standard, resulting in additional assets and liabilities (both current and non-current portions) totaling $12.5 million shown on the balance sheet at March 31, 2019.*

Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities	March 31, 2019	December 31, 2018
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Preferred stock, par value $0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	$ —	$ —
Common stock, par value $0.4867 per share (authorized 50,000,000 shares)	7,980	7,971
Additional paid-in capital	255,307	255,651
Retained earnings	284,111	261,530
Accumulated other comprehensive loss	(3,739)	(6,713)
Deferred compensation obligation	4,376	3,854
Treasury stock	(4,376)	(3,854)
Total stockholders' equity	543,659	518,439
Long-term debt, net of current maturities	285,998	316,020
Total capitalization	829,657	834,459
Current Liabilities		
Current portion of long-term debt	71,509	11,935
Short-term borrowing	276,393	294,458
Accounts payable	75,277	129,804
Customer deposits and refunds	29,710	34,155
Accrued interest	4,505	2,317
Dividends payable	6,067	6,060
Accrued compensation	8,506	13,923
Regulatory liabilities	15,085	7,883
Derivative liabilities, at fair value	6,798	14,871
Other accrued liabilities [1]	14,719	12,828
Total current liabilities	508,569	528,234
Deferred Credits and Other Liabilities		
Deferred income taxes	160,912	156,820
Regulatory liabilities	132,686	135,039
Environmental liabilities	7,370	7,638
Other pension and benefit costs	29,822	28,513
Operating lease - liabilities [1]	10,873	—
Deferred investment tax credits and other liabilities	2,908	2,968
Total deferred credits and other liabilities	344,571	330,978
Total Capitalization and Liabilities	$ 1,682,797	$ 1,693,671

[1] During the first quarter of 2019, the Company adopted a new lease accounting standard, resulting in additional assets and liabilities (both current and non-current portions) totaling $12.5 million shown on the balance sheet at March 31, 2019.

Chesapeake Utilities Corporation and Subsidiaries
Distribution Utility Statistical Data (Unaudited)

	For the Three Months Ended March 31, 2019				For the Three Months Ended March 31, 2018			
	Delmarva NG Distribution	*Chesapeake* Utilities Florida NG Division	FPU NG Distribution	FPU Electric Distribution	Delmarva NG Distribution	Chesapeake Utilities Florida NG Division	FPU NG Distribution	FPU Electric Distribution
Operating Revenues *(in thousands)*								
Residential	$ 29,971	$ 1,785	$ 10,720	$ 9,859	$ 35,314	$ 1,761	$ 11,182	$ 11,533
Commercial	13,141	1,738	7,707	7,816	15,830	1,722	8,331	9,157
Industrial	2,388	3,266	5,994	610	2,306	1,871	6,536	400
Other [1]	(822)	1,111	(635)	(3,907)	(1,743)	510	(2,836)	(2,349)
Total Operating Revenues	$ 44,678	$ 7,900	$ 23,786	$ 14,378	$ 51,707	$ 5,864	$ 23,213	$ 18,741
Volume (in Dts for natural gas and MWHs for electric)								
Residential	2,220,375	132,872	505,326	65,511	2,240,555	140,759	523,062	78,528
Commercial	1,653,320	1,248,764	504,046	61,829	1,705,426	1,239,936	535,544	67,740
Industrial	1,511,308	7,333,850	1,347,237	7,750	1,509,039	2,334,243	1,304,530	4,520
Other	17,859	—	555,391	—	12,533	—	468,556	1,896
Total	5,402,862	8,715,486	2,912,000	135,090	5,467,553	3,714,938	2,831,692	152,684
Average Customers								
Residential	73,976	16,988	56,829	24,379	71,233	16,223	55,280	24,644
Commercial[2]	7,148	1,529	3,897	7,232	7,024	1,460	3,927	7,481
Industrial[2]	168	17	2,415	2	153	73	2,251	2
Other	9	—	12	—	6	—	17	—
Total	81,301	18,534	63,153	31,613	78,416	17,756	61,475	32,127

(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 or changes in taxes, such as the TCJA, which are passed through to customers. This amount also includes the reserve for estimated customer refunds associated with the TCJA.

(2) Certain volumes and customers have been reclassified when compared to the prior year for consistency with current year presentation.

Exhibit C-1 "Annual Reports"
Exhibit C-2 "SEC Filings"

FOR IMMEDIATE RELEASE
February 28, 2018
NYSE Symbol: CPK

CHESAPEAKE UTILITIES CORPORATION REPORTS FOURTH QUARTER AND FISCAL YEAR 2017 RESULTS

- **2017 net income totaled $58.1 million or $3.55 per share, including a one-time $0.87 per share deferred income tax benefit associated with the Tax Cuts and Jobs Act of 2017 ("TCJA") and a $0.21 per share unrealized mark-to-market ("MTM") loss on financial derivatives contracts**
- **Fourth quarter 2017 net income totaled $26.1 million, or $1.59 per share, including the one-time deferred income tax benefit and unrealized MTM loss**
- **Strong growth in natural gas distribution and transmission, propane and CHP plant operations generated $21.3 million in incremental gross margin* for 2017**
- **The first segment of Eastern Shore's $117 million pipeline expansion project was placed into service during the fourth quarter**

Dover, Delaware — Chesapeake Utilities Corporation (NYSE: CPK) ("Chesapeake Utilities" or the "Company") today announced financial results for the year and the fourth quarter ended December 31, 2017. The Company's net income for the year was $58.1 million, or $3.55 per share, an increase of $13.4 million, or $0.69 per share, compared to 2016. The higher net income and earnings per share ("EPS") reflected continued customer growth in the Company's natural gas and propane distribution operations and expansion of its gas transmission operations, full year contributions from Eight Flags Energy LLC's ("Eight Flags") Combined Heat and Power ("CHP") plant, increased profitability for the propane operations and for Aspire Energy of Ohio, LLC ("Aspire Energy"), a partial year's impact of new base rates for Eastern Shore Natural Gas Company ("Eastern Shore"), and the favorable impact of Federal tax law changes on the revaluation of net deferred tax assets and liabilities of the Company's unregulated businesses. A detailed discussion of operating results begins on page 3.

"2017 was an exceptional year for the Company," stated Michael P. McMasters, President and Chief Executive Officer. "Recently completed growth projects, in addition to numerous other strategic growth initiatives across all of our businesses, generated our eleventh record year of earnings. Construction of Eastern Shore's largest ever expansion project is underway with expected completion in phases throughout 2018, and in Florida construction is underway on several pipeline and distribution projects to serve growth in new and existing market areas," he added. "Our employees continue to identify and evaluate new growth opportunities while profitably managing current projects, maintaining operating efficiency and providing safe, reliable service to our customers. Changing regulatory and energy environments and customer energy options create new challenges and opportunities that our team recognizes and embraces. We continually refine our strategic focus to harvest benefits from the challenges of accelerating change and to increase our portfolio of growth opportunities and profitable capital investments in 2018 and beyond," he concluded.

Significant Items Impacting Earnings

Results for the year and fourth quarter of 2017 were impacted by the following significant items:

For the period ended December 31,	**2017**		**Fourth Quarter**	
(in thousands, except per share data)	**Net Income**	**EPS**	**Net Income**	**EPS**
Reported (GAAP) Earnings	**$ 58,124**	**$ 3.55**	**$ 26,101**	**$ 1.59**
Tax reform impact	(14,299)	(0.87)	(14,299)	(0.87)
Unrealized MTM loss	3,499	0.21	3,467	0.21
Adjusted (Non-GAAP) Earnings*	**$ 47,324**	**$ 2.89**	**$ 15,269**	**$ 0.93**

Excluding the tax reform impact and the unrealized MTM loss, earnings for the year and fourth quarter would have been $2.89 and $0.93 per share, respectively.

As a result of the TCJA, the Company's 2017 annual and fourth quarter EPS included a $0.87 per share non-cash benefit from the revaluation of the Company's net deferred tax assets and liabilities associated with the Company's unregulated businesses. We are awaiting formal notice from the federal and state commissions that regulate our gas and electric distribution and transmission businesses on the applicability and timing of the implementation of the tax law changes in regard to customer rates as well as the applicability, timing, and treatment of net deferred tax assets and liabilities. We will provide updates as we receive formal notices and rate orders from the regulatory authorities. The Company estimates that, beginning in 2018, the TCJA corporate federal income tax rate will increase annual EPS between $0.10 and $0.15, primarily from unregulated businesses, assuming normal weather and business conditions, and absent the impact of fair value MTM accounting.

Peninsula Energy Services Company, Inc. ("PESCO") utilizes financial derivatives contracts to lock in the gross margin associated with physical gas purchased and pipeline capacity used for meeting expected demand under PESCO's various contracts, including its asset management contracts. Whenever possible, PESCO utilizes hedge accounting to better match hedged items and hedging instruments. However, in those situations where hedge accounting is not appropriate, the Company utilizes MTM accounting. As a result of the significant regional natural gas price movement at the end of the year, PESCO recognized an unrealized MTM loss of $0.21 per share that reflected the fair value of the financial derivative contracts on December 31, 2017. Derivatives accounting has no impact on the economic gain or loss from PESCO's

purchase or sale contracts, even though MTM accounting may create mismatched gains or losses in different reporting periods.

For the fourth quarter of 2017, the Company reported net income of $26.1 million, or $1.59 per share, an increase of $14.2 million, or $0.86 per share, compared to the same quarter in 2016. Fourth quarter 2017 results also included the $0.87 gain from the tax law changes and the $0.21 charge for PESCO's unrealized MTM loss.

**This press release includes references to non-Generally Accepted Accounting Principles ("GAAP") financial measures, including gross margin and Adjusted EPS. A "non-GAAP financial measure" is generally defined as a numerical measure of a company's historical or future performance that includes or excludes amounts, or that is subject to adjustments, so as to be different from the most directly comparable measure calculated or presented in accordance with GAAP. Our management believes certain non-GAAP financial measures, when considered together with GAAP financial measures, provide information that is useful to investors in understanding period-over-period operating results separate and apart from items that may, or could, have a disproportionately positive or negative impact on results in any particular period.*

The Company calculates "gross margin" by deducting the cost of sales from operating revenue. Cost of sales includes the purchased fuel cost for natural gas, electricity and propane, and the cost of labor spent on direct revenue-producing activities and excludes depreciation, amortization and accretion. Other companies may calculate gross margin in a different manner. Gross margin should not be considered an alternative to operating income or net income, both of which are determined in accordance with GAAP. The Company believes 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 the Company under its allowed rates for regulated operations and under its competitive pricing structures for unregulated businesses. The Company's management uses gross margin in measuring its business units' performance. The Company believes that gross margin is a useful and meaningful measure for investors as it excludes the impact of several unusual items, including fair value accounting, timing adjustments associated with energy-related transactions and the impact of tax reform, which will not impact future results in the same magnitude. The Company calculates Adjusted EPS by excluding the impact of certain significant new non-cash items, including the impact of the revaluation of the Company's unregulated energy segment's deferred assets and liabilities, due to the TCJA changes, and the timing related to the unrealized MTM loss.

Operating Results for the Years Ended December 31, 2017 and 2016

Operating income increased by $1.7 million to $85.8 million for 2017. This increase was driven by an $18.9 million, or seven percent, increase in gross margin, which was partially offset by a $17.2 million increase in operating expenses, due to a $5.1 million increase in depreciation, asset removal, amortization and property taxes and a $12.0 million increase in other operating expenses to support growth. Excluding the unrealized MTM loss, gross margin grew by $24.6 million, or nine percent, and operating income rose $7.5 million, or nine percent, for 2017 versus 2016.

Regulated Energy

Operating income for the Regulated Energy segment increased by $3.3 million in 2017 compared to 2016. This increase was driven by an $11.5 million increase in gross margin, which was partially offset by $8.2

million in higher operating expenses associated with the margin growth. The significant components of the gross margin increase included:

- $3.7 million of incremental revenue from the implementation of new base rates for Eastern Shore, which were effective August 1, 2017;
- $2.8 million in additional margin from customer growth in the Company's natural gas distribution businesses (excluding service expansions);
- $2.1 million generated from recently completed natural gas transmission expansions, which are more fully discussed in the "Major Projects and Initiatives" section later in this press release;
- $1.9 million generated from additional GRIP investments in the Florida natural gas distribution operations;
- $831,000 generated as a result of the rate case settlement by the Company's Delaware natural gas distribution operations; and
- $537,000 from new natural gas transmission and distribution services provided to Eight Flags' CHP plant.

The significant drivers of the $8.2 million increase in operating expenses included:

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

Unregulated Energy

Operating income for the Unregulated Energy segment for 2017 was $12.5 million, a decrease of $1.4 million, or ten percent, compared to the same period in 2016. The decreased operating income was the net result of increased growth in all the unregulated energy businesses, which was more than offset by PESCO's unrealized MTM loss. Excluding the impact of the unrealized MTM loss, gross margin grew by $13.4 million, or 20.6 percent, and operating income rose by $4.4 million, or 31.9 percent, during 2017 compared to 2016. In particular, PESCO's gross margin and operating income, exclusive of the unrealized MTM loss, grew by $3.4 million, or 72.7 percent, and $772,000, or 41.4 percent, respectively.

The significant components of the gross margin increase included:

- $4.4 million in additional margin from Eight Flags' CHP plant, reflecting a full year of operations in 2017 compared to slightly more than six months in 2016;
- $3.4 million in margin growth for PESCO, generated primarily from natural gas sales to end users within one Columbia Gas of Ohio customer pool under a supplier agreement, which expired on March 31, 2017, as well as increased margin from commercial and industrial customers served in Florida;
- $2.8 million in additional margin from the propane distribution operations, composed of:
  - $951,000 from higher propane sales, due to colder weather in December;

  - $678,000 of additional gross margin from wholesale propane sales, due to increased volumes and favorable supply management activities by the Company's Delmarva propane operations and higher throughput margins from the Florida propane operations; and
  - $645,000 of additional retail gross margin, also attributable to favorable supply management activities.
- $2.3 million of additional margin from Aspire Energy as a result of:
  - $1.2 million associated with higher volumes, primarily as a result of customer growth for the local distribution companies served and colder temperatures in December; and
  - $1.1 million of additional gross margin as a result of pricing amendments to long-term gas sales agreements.
- $658,000 of gross margin due to the absence of Xeron Inc.'s ("Xeron") operating loss recorded in 2016; partially offset by
- $5.8 million associated with PESCO's unrealized MTM loss, which was based upon fair value accounting at year end. A more detailed discussion of the unrealized MTM loss is provided in the Major Projects and Initiatives Section under "PESCO".

The significant components of the $9.0 million increase in operating expenses included:

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

Operating Results for the Quarters Ended December 31, 2017 and 2016

The Company's operating income for the fourth quarter of 2017 was $23.3 million, an increase of $1.4 million, or 6.6 percent, compared to the same quarter in 2016. Excluding PESCO's unrealized MTM loss, gross margin grew by $10.6 million, or 15.1 percent, and operating income rose by $7.2 million, or approximately 33.0 percent, for the fourth quarter of 2017 versus the same quarter in 2016.

Regulated Energy Segment

Operating income for the Regulated Energy segment increased by $4.1 million to $21.2 million for the fourth quarter of 2017, compared to the same quarter in 2016. The increased operating income resulted from a $5.8 million increase in gross margin, partially offset by a $1.7 million increase in operating expenses. The significant components of the gross margin increase included:

- $2.7 million generated from implementation of new base rates for Eastern Shore;
- $840,000 in increased customer consumption of energy as a result of colder weather experienced during the fourth quarter of 2017;
- $791,000 in additional margin from customer growth in our natural gas distribution businesses (excluding service expansions);

- $639,000 generated from recently completed natural gas transmission expansions;
- $413,000 in margin recognized from the settled Delaware division rate case and the absence of the associated rate refund reserve recorded in the fourth quarter of 2016; and
- $283,000 generated by additional GRIP investments in the Florida natural gas distribution operations.

The significant components of the $1.7 million increase in operating expenses included:

- $2.0 million in higher staffing and associated costs for additional personnel to support growth;
- $649,000 in higher depreciation expense, amortization, asset removal and property tax costs associated with capital investments; offset by
- $459,000 in lower outside services expenses; and
- $254,000 in lower benefits and employee-related costs during the quarter.

Unregulated Energy Segment

Operating income for the Unregulated Energy segment for the fourth quarter of 2017 was $2.0 million, a decrease of $2.6 million compared to operating income for the same quarter in 2016. The decreased operating income reflects an $837,000 decrease in gross margin and a $1.8 million increase in operating expenses. Excluding the unrealized MTM loss previously mentioned, gross margin grew by $4.9 million, or 25.2 percent, and operating income increased by $3.2 million, or 69.1 percent, during the fourth quarter of 2017 compared to the same quarter in 2016.

Significant sources of higher gross margin included:

- $1.6 million in margin growth from PESCO, generated primarily from sales in the Appalachian Basin;
- $1.4 million in higher gross margin from the propane operations, consisting primarily of:
  - $694,000 from higher customer consumption of propane due to colder temperatures; and
  - $527,000 in higher gross margin from retail propane sales, due primarily to favorable supply management activities.
- $1.2 million from Aspire Energy, primarily as a result of:
  - $750,000 in higher volumes of natural gas delivered due to colder temperatures in December 2017; and
  - $351,000 in additional gross margin as a result of pricing amendments to long-term gas sales agreements and additional management fees.
- $590,000 of gross margin due to the absence of Xeron's operating loss recorded in the fourth quarter of 2016; offset by
- $5.8 million for PESCO's unrealized MTM loss, based upon fair value accounting at year end.

The significant components of the $1.8 million increase in operating expenses included:

- $1.5 million in higher staffing and associated costs for additional personnel to support growth; and
- $353,000 in higher depreciation, amortization and property tax costs due to increased capital investments and amortization of intangible assets acquired as part of acquisitions consummated in 2017.

Matters discussed in this release may include forward-looking statements that involve risks and uncertainties. Actual results may differ materially from those in the forward-looking statements. Please refer

to the Safe Harbor for Forward-Looking Statements in the Company's 2017 Annual Report on Form 10-K for further information on the risks and uncertainties related to the Company's forward-looking statements.

Conference Call

Chesapeake Utilities Corporation will host a conference call on March 2, 2018 at 10:30 a.m. Eastern Time to discuss the Company's financial results for the year and quarter ended December 31, 2017. To participate in this call, dial 855.801.6270 and reference Chesapeake Utilities' 2017 Financial Results Conference Call. To access the replay recording of this call, please visit the Company's website at http://investor.chpk.com/results.cfm or download the replay on your mobile device by accessing the Audiocast section of the Company's IR App.

About Chesapeake Utilities Corporation

Chesapeake Utilities is a diversified energy company engaged in natural gas distribution, transmission, gathering and processing, and marketing; electricity generation and distribution; propane gas distribution; and other businesses. Information about Chesapeake Utilities and its family of businesses is available at http://www.chpk.com or through its IR App.

Please note that Chesapeake Utilities Corporation is not affiliated with Chesapeake Energy, an oil and natural gas exploration company headquartered in Oklahoma City, Oklahoma.

For more information, contact:

Beth W. Cooper
Senior Vice President & Chief Financial Officer
302.734.6799

Financial Summary

(in thousands, except per-share data)

For the Periods Ended December 31,	Year Ended 2017	Year Ended 2016	Fourth Quarter 2017	Fourth Quarter 2016
Gross Margin				
Regulated Energy	$ 207,541	$ 196,080	$ 56,394	$ 50,633
Unregulated Energy	72,572	64,962	18,745	19,582
Other businesses and eliminations	(444)	(225)	(119)	(58)
Total Gross Margin	$ 279,669	$ 260,817	$ 75,020	$ 70,157
Operating Income				
Regulated Energy	$ 73,160	$ 69,851	$ 21,245	$ 17,191
Unregulated Energy	12,477	13,844	1,974	4,577
Other businesses and eliminations	206	401	44	51
Total Operating Income	$ 85,843	$ 84,096	$ 23,263	$ 21,819
Other (expense) income	(765)	(441)	(121)	(372)
Interest charges	12,645	10,639	3,513	2,643
Income taxes	14,309	28,341	(6,472)	6,941
Net Income	$ 58,124	$ 44,675	$ 26,101	$ 11,863
Earnings Per Share of Common Stock				
Basic	$ 3.56	$ 2.87	$ 1.60	$ 0.73
Diluted	$ 3.55	$ 2.86	$ 1.59	$ 0.73

Financial Summary Highlights

Key variances for the year ended December 31, 2017 included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2016 Reported Results	$ 73,016	$ 44,675	$ 2.86
Adjusting for unusual items:			
Federal tax reform impact	—	14,299	0.87
PESCO - unrealized MTM loss	(5,783)	(3,499)	(0.21)
Impact of winding down of Xeron operations and absence of 2016 loss	745	451	0.03
Weather impact	578	350	0.02
	(4,460)	11,601	0.71
Increased (Decreased) Gross Margins:			
Eight Flags' CHP plant	4,901	2,965	0.19
Implementation of new base rates for Eastern Shore*	3,693	2,234	0.14
PESCO - margin from operations	3,365	2,036	0.13
Natural gas growth (excluding service expansions)	2,818	1,705	0.11
Service expansions*	2,062	1,248	0.08
GRIP*	1,902	1,151	0.07
Aspire Energy rates and management fees	1,125	680	0.04
Customer consumption (non-weather)	721	436	0.03
Implementation of Delaware division settled rates	831	503	0.03
Wholesale propane sales and margins	678	410	0.03
Retail propane margins	645	390	0.02
Sandpiper margins associated with conversions	291	176	0.01
	23,032	13,934	0.88
(Increased) Decreased Other Operating Expenses:			
Higher payroll expense	(6,487)	(3,925)	(0.25)
Higher depreciation, asset removal and property tax costs due to new capital investments	(5,120)	(3,098)	(0.20)
Eight Flags' operating expenses	(2,920)	(1,767)	(0.11)
Higher benefit and other employee-related expenses	(1,485)	(899)	(0.06)
Higher regulatory expenses associated with rate filings	(1,005)	(608)	(0.04)
Higher taxes other than property and income taxes	(739)	(447)	(0.03)
Lower credit, collections & customer service expenses	515	311	0.02
Lower outside services and facilities maintenance costs	417	252	0.02
Higher vehicle expenses	(372)	(225)	(0.01)
Higher sales and advertising expenses	(259)	(157)	(0.01)
	(17,455)	(10,563)	(0.67)
Increase in outstanding shares from the September 2016 public offering	—	—	(0.16)
Interest charges	(2,006)	(1,214)	(0.08)
Change in other expense	(191)	(115)	(0.01)
Change in effective tax rate prior to tax reform	—	(500)	(0.03)
Net other changes	497	306	0.05
Year ended December 31, 2017 Reported Results	$ 72,433	$ 58,124	$ 3.55

*** See the Major Projects and Initiatives table later in this press release.**

Key variances for the quarter ended December 31, 2017 included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Fourth Quarter of 2016 Reported Results	$ 18,804	$ 11,863	$ 0.73
Adjusting for unusual items:			
Federal tax reform impact	—	14,299	0.87
PESCO - unrealized MTM loss	(5,765)	(3,467)	(0.21)
Weather impact	1,885	1,133	0.07
Impact of winding down of Xeron operations and absence of 2016 loss	1,086	653	0.04
	(2,794)	12,618	0.77
Increased (Decreased) Gross Margins:			
Implementation of new base rates for Eastern Shore*	2,673	1,607	0.10
PESCO - margin from operations	1,587	954	0.06
Natural gas growth (excluding service expansions)	791	476	0.03
Service expansions*	639	384	0.02
Retail propane margins	527	317	0.02
Delaware division rate case*	413	248	0.02
Aspire Energy rates and management fees	396	238	0.01
GRIP*	283	170	0.01
Eight Flags' CHP*	180	108	0.01
	7,489	4,502	0.28
(Increased) Decreased Other Operating Expenses:			
Higher payroll expense	(3,497)	(2,103)	(0.13)
Higher depreciation, asset removal and property tax costs due to new capital investments	(999)	(601)	(0.04)
Lower outside services and facilities maintenance costs	865	520	0.03
Lower benefit and other employee-related expenses	172	104	0.01
Higher regulatory expenses	(150)	(90)	(0.01)
Lower Eight Flags' operating expenses	99	60	—
	(3,510)	(2,110)	(0.14)
Interest Charges	(870)	(523)	(0.03)
Change in effective tax rate prior to tax reform	—	(581)	(0.04)
Net Other Changes	510	332	0.02
Fourth Quarter of 2017 Reported Results	**$ 19,629**	**$ 26,101**	**$ 1.59**

*** See the Major Projects and Initiatives table later in this press release.**

The following information highlights certain key factors contributing to the Company's results for the year and quarter ended December 31, 2017:

Major Projects and Initiatives

The following table summarizes gross margin (dollars in thousands) for the Company's existing and future major projects and initiatives. Gross margin reflects operating revenue less cost of sales, excluding depreciation, amortization and accretion:

	Gross Margin for the Period							
	Year Ended December 31,			Three Months Ended December 31,			Estimate for	
	2017	2016	Variance	2017	2016	Variance	2018	2019
Existing Major Projects and Initiatives								
Capital Investment Projects	$ 38,251	$ 29,819	$ 8,432	$ 9,887	$ 9,218	$ 669	$ 34,041	$ 34,137
Eastern Shore Rate Case [1]	3,693	—	3,693	2,673	—	2,673	9,800	9,800
Settled Delaware Division Rate Case	2,318	1,487	831	553	140	413	2,250	2,250
Electric Limited Proceeding	94	—	94	94	—	—	1,558	1,558
Total Existing Major Projects and Initiatives	$ 44,356	$ 31,306	$ 13,050	$ 13,207	$ 9,358	$ 3,755	$ 47,649	$ 47,745
Future Major Projects and Initiatives								
Capital Investment Projects								
2017 Eastern Shore System Expansion	$ 433	$ —	$ 433	$ 433	$ —	$ 433	$ 9,708	$ 15,799
Northwest Florida Expansion	—	—	—	—	—	—	3,484	6,032
Other Florida Pipeline Expansions	—	—	—	—	—	—	635	1,131
Total Future Major Projects and Initiatives	$ 433	$ —	$ 433	$ 433	—	$ 433	$ 13,827	$ 22,962
Total	$ 44,789	$ 31,306	$ 13,483	$ 13,640	$ 9,358	$ 4,188	$ 61,476	$ 70,707

[1]Eastern Shore filed an uncontested settlement agreement in December 2017, which is pending final approval by the Federal Energy Regulatory Commission ("FERC").

Major Projects and Initiatives Recently Completed

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

	Gross Margin for the Period					
	Year Ended December 31,			Three Months Ended December 31,		
	2017	2016	Variance	2017	2016	Variance
Capital Investment Projects:						
Service Expansions:						
Short-term contracts (Delaware)	$ 6,522	$ 11,454	$ (4,932)	$ 1,330	$ 3,184	$ (1,854)
Long-term contracts (Delaware)	8,141	1,815	6,326	2,274	449	1,825
Long-term contracts (Florida)	235	—	235	235	—	235
Total Service Expansions	14,898	13,269	1,629	3,839	3,633	206
Florida GRIP	13,454	11,552	1,902	3,452	3,169	283
Eight Flags' CHP Plant	9,899	4,998	4,901	2,596	2,416	180
Total Capital Investment Projects	$ 38,251	$ 29,819	$ 8,432	$ 9,887	$ 9,218	$ 669

Service Expansions

White Oak Mainline Expansion Project

In August 2014, Eastern Shore entered into a precedent agreement with an electric power generator in Kent County, Delaware, to provide a 20-year OPT<90 natural gas transmission service for 45,000 Dts/day. In July 2016, the FERC authorized Eastern Shore to construct and operate the project, which consists of 5.4 miles of 16-inch pipeline looping and new compression capability in Delaware. Eastern Shore provided interim services to this customer until construction was completed and long-term service commenced in March 2017. This service generated an additional gross margin of $85,000 during the year ended December 31, 2017 compared to 2016. There was no incremental margin during the fourth quarter as the permanent services replaced the interim services. Service provided under the 20-year agreement generated gross margin of $7.5 million during 2017 and is expected to generate between $5.8 million and $7.8 million annually through the remaining term of the agreement.

TETLP Upgrades

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

2016 Eastern Shore System Reliability Project

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

New Smyrna Beach, Florida Project

In the fourth quarter of 2017, Peninsula Pipeline Company, Inc. ("Peninsula Pipeline"), the Company's wholly-owned Florida intrastate pipeline subsidiary, started construction of a 14-mile transmission pipeline in Volusia County, Florida, that interconnects with Florida Gas Transmission Company's ("FGT") pipeline. Peninsula Pipeline entered into a 20-year agreement with Florida Public Utilities ("FPU"), which provides FPU with capacity to serve its current and planned customer growth. Peninsula Pipeline recognized $235,000 of gross margin from this expansion during the year and quarter ended December 31, 2017, and expects to recognize gross margin of approximately $1.4 million annually thereafter.

GRIP

GRIP is a natural gas pipe replacement program approved by the Florida Public Service Commission ("PSC"), designed to expedite the replacement of qualifying distribution mains and services (any material other than coated steel or plastic) to enhance the reliability and integrity of the Florida natural gas distribution systems. This program allows recovery, through regulated rates, of capital and other program-related costs, inclusive of a return on investment, associated with the replacement of the mains and services. Since the program's inception in August 2012, the Company has invested $113.6 million to replace 247 miles of qualifying distribution mains, including $10.8 million and $26.0 million during 2017 and 2016, respectively. GRIP generated additional gross margin of $1.9 million and $283,000 for the year and quarter ended December 31, 2017, compared to the same periods in 2016, respectively.

Eight Flags' CHP Plant

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

The CHP plant is powered by natural gas transported by FPU, through its distribution system, and by Peninsula Pipeline. For the year and quarter ended December 31, 2017, Eight Flags and other affiliates of Chesapeake Utilities generated $4.9 million and $180,000, respectively, in additional gross margin as a result of these services. The increase for the year ended December 31, 2017, includes $537,000 in gross margin from FPU and Peninsula Pipeline.

Regulatory Proceedings

Eastern Shore Rate Case

In December 2017, Eastern Shore filed an uncontested settlement agreement for its January 2017 base rate case filing with the FERC. Under the terms of the settlement agreement, Eastern Shore will recover the costs of its 2016 System Reliability Project, along with the cost of investments and expenses associated with various expansion, reliability and safety initiatives. Pursuant to the settlement agreement, which is now subject to the FERC's review and action, Eastern Shore will record and recognize an increase in annual base rates of approximately $9.8 million, prior to any federal tax reform impact. The settlement agreement prescribes the methodology for adjusting these rates as a result of tax reform. For the twelve and three months ended December 31, 2017, Eastern Shore recognized incremental gross margin of $3.7 million and $2.7 million, respectively.

Delaware Division Rate Case

In December 2016, the Delaware PSC approved a settlement agreement, which, among other things, provided for an increase in the Company's Delaware division revenue requirement of $2.3 million and a rate of return on common equity of 9.75 percent. The new authorized rates went into effect on January 1, 2017. For the year and three months ended December 31, 2017, the Company recorded incremental gross margin of approximately $831,000 and $413,000, respectively, related to the rate case.

Electric Limited Proceeding

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

Major Projects and Initiatives Currently Underway

2017 Expansion Project

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

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Northwest Florida Expansion Project

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

(Palm Beach County) Belvedere, Florida Project

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

Other Natural Gas Growth - Distribution Operations

Customer growth for the Delmarva natural gas distribution operations generated $1.6 million and $594,000 in additional gross margin for the year and quarter ended December 31, 2017, respectively, compared to the same periods in 2016. The average number of residential customers on the Delmarva Peninsula increased by 3.8 percent in 2017 compared to 2016.

Florida natural gas distribution operations generated $1.2 million and $197,000 in additional gross margin for the year and quarter ended December 31, 2017, respectively, compared to the same periods in 2016, with approximately two-thirds of the margin growth generated from commercial and industrial customers and one-third of the margin growth generated from new residential customers.

Weather and Consumption

Colder temperatures during the fourth quarter of 2017 increased customer consumption and generated $1.9 million in additional gross margin compared to 2016. Although 2017 was warmer than the prior year, colder temperatures in the fourth quarter generated additional margin for the year of $578,000. Compared to normal, weather for the quarter and year ended 2017 was warmer, which reduced gross margin by $2.0 million and by $1.0 million for the year and fourth quarter, respectively. The following table summarizes the heating degree-days ('HDD") and cooling degree-days ("CDD") information for the years and quarters ended December 31, 2017 and 2016 and shows variances between actual and "Normal" (10-year average) HDD and CDD for those periods.

HDD and CDD Information

For the Periods Ended December 31,	2017	2016	Variance	Q4 2017	Q4 2016	Variance
Delmarva						
Actual HDD	**3,800**	3,979	(179)	**1,538**	1,389	149
10-Year Average HDD ("Normal")	**4,374**	4,453	(79)	**1,529**	1,533	(4)
Variance from Normal	**(574)**	(474)		**9**	(144)	
Florida						
Actual HDD	**533**	672	(139)	**235**	158	77
10-Year Average HDD ("Normal")	**818**	828	(10)	**263**	275	(12)
Variance from Normal	**(285)**	(156)		**(28)**	(117)	
Ohio						
Actual HDD	**5,126**	5,529	(403)	**2,057**	1,936	121
10-Year Average HDD ("Normal")	**5,914**	5,918	(4)	**2,048**	2,055	(7)
Variance from Normal	**(788)**	(389)		**9**	(119)	
Florida						
Actual CDD	**3,013**	3,152	(139)	**407**	360	47
10-Year Average CDD ("Normal")	**2,865**	2,820	45	**286**	272	14
Variance from Normal	**148**	332		**121**	88	

Note: The Company continually refines and updates its weather calculations. These refinements may result in the annual impact varying from the aggregate of the quarterly variances previously disclosed.

Propane Results

The Company's Florida and Delmarva Peninsula propane distribution operations continue to pursue a multi-pronged growth strategy, which includes targeting retail and wholesale customer growth in existing markets, both organically and through acquisitions; incremental growth from recent and planned start-ups in new markets, targeting new community gas systems in high growth areas; further build-out of the Company's propane vehicular platform through its Alliance AutoGas fueling stations; and optimization of its supply portfolio to generate incremental margin opportunities. Over the years, the Company has been focused on meeting customer energy demand. It has created a portfolio of offerings regardless of whether the customer is served via a pipeline or through an individual tank. Alliance AutoGas is the Company's most recent offering that meets customers' demands for clean-burning fuel alternatives.

These operations generated $2.8 million and $1.4 million in incremental margin for the year and quarter ended December 31, 2017, respectively, compared to the same periods in 2016. Higher volume due to colder weather in the latter part of December 2017 was the most significant driver for the quarter. In addition, successful marketing initiatives led to increased volumes sold and revenues from service contracts. Supply management initiatives, including favorable hedging of propane purchases, have facilitated improvement in retail propane margins as well as opportunities to generate incremental margin from wholesale sales.

The following tables summarize gross margin for the Company's propane distribution operations for the year and quarter ended December 31, 2017:

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

For the Quarter Ended	**12/31/2017**
Additional customer consumption - weather	$ 694
Higher retail propane margins per gallon	527
Increased customer consumption driven by growth and other factors	97
Other	82
	$ 1,400

PESCO

PESCO markets and sells natural gas to wholesale, industrial and commercial customers and manages natural gas storage and transportation assets in several regions. PESCO also provides management of storage and transportation assets for natural gas producers and regulated utilities. These management transactions typically involve the release of storage and/or transportation capacity in combination with either an obligation to purchase and/or deliver natural gas.

In conjunction with the active management of these contracts, PESCO generates financial margin by identifying market opportunities and simultaneously entering into natural gas purchase/sale, storage or transportation contracts and/or financial derivatives contracts. The financial derivatives contracts consist primarily of exchange-traded futures that are used to manage volatility in natural gas market prices. Volatility in PESCO's recorded gross margin and operating income can occur over periods of time due to changes in the value of financial derivatives contracts prior to the time of the settlement of the financial derivatives and the purchase or sale of the underlying physical commodity. Derivatives accounting does not impact the economic gains or losses arising from the purchase/sale contracts. PESCO's results may also fluctuate based on the actual demand of its customers, relative to its initial estimates of their demand, and PESCO's ability to manage its supply portfolio considering weather and other factors, including pipeline constraints.

In April 2017, PESCO entered into 3-year asset management agreements with the Company's Delmarva Peninsula natural gas distribution operations, whereby PESCO manages a portion of their natural gas transportation and storage capacity. In the fourth quarter, PESCO executed financial derivatives contracts to lock in margin associated with a specified quantity of natural gas to be delivered in the first quarter of 2018. As regional natural gas prices rose suddenly at the end of the fourth quarter, the financial derivatives contracts were valued based on MTM accounting at year end, and an unrealized loss was recorded. Upon their settlement during the first quarter of 2018, these derivatives contracts will be matched against the physical contracts with the margin realized at that time.

For the year and quarter ended December 31, 2017, PESCO's gross margin decreased by $2.4 million and $4.2 million, respectively, largely due to the $5.8 million of unrealized MTM loss related to financial derivatives contracts that were valued at the end of the year. This loss was offset by $3.4 million and $1.6 million for the year and quarter ended December 31, 2017, respectively, from: (a) additional gross margin generated primarily from natural gas sales to end users within one Columbia Gas of Ohio customer pool under a supplier agreement, which expired on March 31, 2017, and (b) increased margin from commercial and industrial customers served in Florida.

PESCO utilizes hedge accounting to better match the hedged items and the hedging instruments, when appropriate, and, in those situations where hedge accounting is not appropriate, the Company utilizes MTM accounting. The Company will be adopting the updated hedge accounting standard in 2018, which it expects will reduce the MTM volatility in PESCO's results due to better alignment of risk management activities and financial reporting, risk component hedging and certain other simplifications of hedge accounting guidance. PESCO's results for the year and fourth quarter of 2017, adjusted for the unrealized MTM loss were as follows:

For the period ended December 31, (in thousands)	Gross Margin 2017	Gross Margin Fourth Quarter	Operating Income 2017	Operating Income Fourth Quarter
As Reported	**$ 2,212**	**$ (3,537)**	**$ (3,147)**	**$ (5,328)**
Unrealized MTM loss	5,783	5,765	5,783	5,765
Adjusted totals excluding unrealized MTM loss	**$ 7,995**	**$ 2,228**	**$ 2,636**	**$ 437**

Xeron

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

Positioning the Company for Future Growth

Resource Allocation

To support and continue its growth, the Company has expanded, and will continue to expand, its resources and capabilities. Eastern Shore continues to significantly expand its transmission system, and has therefore increased its staffing. Growth in non-regulated energy businesses, including Aspire Energy, PESCO and Eight Flags, requires additional staff as well as corporate resources to support the increased level of business operations. Finally, to allow the Company to continue to identify and move growth initiatives forward and to manage their integration into Chesapeake Utilities' growing portfolio, resources have been added in the Company's corporate shared services departments. In the twelve and three months ended December 31, 2017, the Company's staffing and associated costs increased by $8.0 million and $3.3 million, or 10.4 percent and 4.4 percent, respectively, compared to the same periods in 2016. The Company requested recovery of most of Eastern Shore's increased staffing costs in its 2017 rate case filing, for which we have filed an uncontested settlement agreement with the FERC. The Company is prudently managing the pace and magnitude of the investments being made, while ensuring that it appropriately expands its human resources and systems capabilities to manage current growth and to identify and capitalize on future growth opportunities. In support of these financial goals, the Company continues to pursue investments that are typically earnings accretive within the first twelve months.

Financing the Growth

Chesapeake Utilities' target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. This target capital structure ensures that the Company maintains a strong balance sheet to support continued growth. Over the past several years, the Company has been deploying increased amounts of capital on new projects, many of which have longer construction periods. The Company seeks to align the permanent financing of these capital projects with the in-service dates to the extent feasible.

Accordingly, the Company has utilized increasing amounts of short-term debt to fund these projects. In 2016, shortly after the completion of Eight Flags' CHP plant and several other key growth projects, the Company completed a $59.8 million public offering of its common stock, pursuant to which the number of

outstanding shares increased by 960,488. This increase in outstanding shares lowered EPS by approximately $0.16 per share for the twelve months ended December 31, 2017.

As several large projects were completed in 2017, the Company also refinanced $70.0 million of short-term debt as 3.25 percent senior notes. While very competitively priced, the refinancing resulted in increased interest expense of $1.6 million, or $0.06 per share. The Company has also recently executed a $100 million shelf agreement with New York Life Investors LLC, pursuant to which $100 million of new senior notes will be issued in two tranches in 2018 at an average interest rate of 3.53 percent. The Company expects to access additional permanent capital to align the financing with new investments and to maintain a solid balance sheet to support future capital deployment.

Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Income (Unaudited)
For the Periods Ended December 31, 2017 and 2016

(in thousands, except shares and per share data)

	Year Ended		Fourth Quarter	
	2017	2016	2017	2016
Operating Revenues				
Regulated Energy	$ 326,310	$ 305,689	$ 87,957	$ 79,059
Unregulated Energy	324,595	203,778	104,133	67,417
Other businesses and eliminations	(33,322)	(10,607)	(11,687)	(4,602)
Total Operating Revenues	617,583	498,860	180,403	141,874
Operating Expenses				
Regulated energy cost of sales	118,769	109,609	31,563	28,425
Unregulated energy and other cost of sales	219,145	128,434	73,819	43,291
Operations	127,571	117,571	34,582	32,200
Maintenance	12,701	12,391	3,331	3,466
Gain from a settlement	(130)	(130)	—	—
Depreciation and amortization	36,599	32,159	9,331	8,667
Other taxes	17,085	14,730	4,513	4,006
Total operating expenses	531,740	414,764	157,139	120,055
Operating Income	85,843	84,096	23,263	21,819
Other expense	(765)	(441)	(121)	(372)
Interest charges	12,645	10,639	3,513	2,643
Income Before Income Taxes	72,433	73,016	19,629	18,804
Income taxes	14,309	28,341	(6,472)	6,941
Net Income	$ 58,124	$ 44,675	$ 26,101	$ 11,863
Weighted Average Common Shares Outstanding:				
Basic	16,336,789	15,570,539	16,344,442	16,302,021
Diluted	16,383,352	15,613,091	16,397,332	16,349,110
Earnings Per Share of Common Stock:				
Basic	$ 3.56	$ 2.87	$ 1.60	$ 0.73
Diluted	$ 3.55	$ 2.86	$ 1.59	$ 0.73

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets (Unaudited)

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities	As of December 31, 2017	2016
(in thousands, except shares and per share data)		
Capitalization		
Preferred stock, par value $0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	$ —	$ —
Common stock, par value $0.4867 per share (authorized 50,000,000 shares)	7,955	7,935
Additional paid-in capital	253,470	250,967
Retained earnings	229,141	192,062
Accumulated other comprehensive loss	(4,272)	(4,878)
Deferred compensation obligation	3,395	2,416
Treasury stock	(3,395)	(2,416)
Total stockholders' equity	486,294	446,086
Long-term debt, net of current maturities	197,395	136,954
Total capitalization	683,689	583,040
Current Liabilities		
Current portion of long-term debt	9,421	12,099
Short-term borrowing	250,969	209,871
Accounts payable	74,688	56,935
Customer deposits and refunds	34,751	29,238
Accrued interest	1,742	1,312
Dividends payable	5,312	4,973
Accrued compensation	13,112	10,496
Regulatory liabilities	6,485	1,291
Derivative liabilities, at fair value	6,247	773
Other accrued liabilities	10,273	7,063
Total current liabilities	413,000	334,051
Deferred Credits and Other Liabilities		
Deferred income taxes	135,850	222,894
Regulatory liabilities	140,978	43,064
Environmental liabilities	8,263	8,592
Other pension and benefit costs	29,699	32,828
Deferred investment tax credits and Other liabilities	5,955	4,750
Total deferred credits and other liabilities	320,745	312,128
Total Capitalization and Liabilities	$ 1,417,434	$ 1,229,219

Chesapeake Utilities Corporation and Subsidiaries
Distribution Utility Statistical Data (Unaudited)

	For the Three Months Ended December 31, 2017				For the Three Months Ended December 31, 2016			
	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution
Operating Revenues *(in thousands)*								
Residential	$ 14,854	$ 1,435	$ 8,157	$ 10,166	$ 12,767	$ 1,312	$ 7,442	$ 9,548
Commercial	7,860	1,493	7,170	9,951	6,697	1,323	7,657	9,890
Industrial	2,236	1,676	5,921	1,609	2,146	1,666	5,185	1,343
Other (1)	5,090	1,039	(444)	(1,640)	2,574	1,040	348	(2,095)
Total Operating Revenues	$ 30,040	$ 5,643	$ 20,804	$ 20,086	$ 24,184	$ 5,341	$ 20,632	$ 18,686
Volumes (in Dts for natural gas and MWHs for electric)								
Residential	792,602	86,682	327,815	66,998	732,491	82,560	314,989	61,963
Commercial	829,713	1,165,579	436,272	74,689	867,780	1,942,337	499,922	71,258
Industrial	1,375,672	3,042,088	1,171,381	15,130	1,352,489	2,600,411	1,106,017	12,230
Other	29,142	—	593,768	1,885	24,514	—	451,014	1,906
Total	3,027,129	4,294,349	2,529,236	158,702	2,977,274	4,625,308	2,371,942	147,357
Average Customers								
Residential	69,532	15,967	54,704	24,648	66,867	15,453	53,555	24,351
Commercial	6,848	1,435	3,962	9,301	6,746	1,399	4,200	7,420
Industrial	155	80	2,186	2	131	73	1,864	2
Other	3	—	3	—	6	—	2	—
Total	76,538	17,482	60,855	33,951	73,750	16,925	59,621	31,773

	For the Year Ended December 31, 2017				For the Year Ended December 31, 2016			
	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution	Delmarva NG Distribution	Chesapeake Utilities' Florida NG Division	FPU NG Distribution	FPU Electric Distribution
Operating Revenues *(in thousands)*								
Residential	$ 57,365	$ 5,600	$ 33,103	$ 44,082	$ 49,841	$ 5,289	$ 28,040	$ 46,459
Commercial	31,585	5,756	30,283	41,141	27,274	5,171	28,569	41,704
Industrial	7,619	6,535	21,647	3,561	7,420	6,474	20,583	3,497
Other (1)	3,504	3,858	(5,353)	(5,918)	1,409	3,704	(2,266)	(7,505)
Total Operating Revenues	$ 100,073	$ 21,749	$ 79,680	$ 82,866	$ 85,944	$ 20,638	$ 74,926	$ 84,155
Volumes (in Dts for natural gas and MWHs for electric)								
Residential	3,368,603	340,570	1,350,413	291,510	3,227,594	342,964	1,308,906	303,654
Commercial	3,274,975	5,156,823	1,863,147	304,235	3,407,184	6,060,468	2,133,842	304,458
Industrial	5,125,633	11,561,309	4,543,775	27,380	5,032,872	11,005,835	4,294,573	29,700
Other	95,415	—	1,875,761	7,511	92,807	—	846,115	8,484
Total	11,864,626	17,058,702	9,633,096	630,636	11,760,457	17,409,267	8,583,436	646,296
Average Customers								
Residential	68,699	15,796	54,410	24,574	66,175	15,340	53,300	24,289
Commercial	6,845	1,421	4,054	7,908	6,746	1,393	4,236	7,404
Industrial	147	79	2,078	2	125	73	1,786	2
Other	5	—	3	—	5	—	2	—
Total	75,696	17,296	60,545	32,484	73,051	16,806	59,324	31,695

(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.

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended: December 31, 2017

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

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "accelerated filer," "large accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company"	Smaller reporting company	☐
		Emerging growth company	☐

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

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

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2017, the last business day of its most recently completed second fiscal quarter, based on the last trade price on that date, as reported by the New York Stock Exchange, was approximately $1.2 billion.

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

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2018 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III, which Proxy Statement shall be filed with the Securities and Exchange Commission within 120 days after the end of registrant's fiscal year ended December 31, 2017.

CHESAPEAKE UTILITIES CORPORATION

FORM 10-K

YEAR ENDED DECEMBER 31, 2017

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GLOSSARY OF DEFINITIONS

AFUDC: Allowance for funds used during construction

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

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

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

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

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

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

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

CGC: Consumer Gas Cooperative, an Ohio natural gas cooperative

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

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

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

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

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

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

CHP: Combined heat and power plant

CIAC: Contributions from customers that are used to construct facilities

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

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

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

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

CP: Certificate of Public Convenience and Necessity

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

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

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

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

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

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

DNREC: Delaware Department of Natural Resources and Environmental Control

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

Dts/d: Dekatherms per day

Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned interstate natural gas transmission subsidiary of Chesapeake Utilities

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

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

EPA: United States Environmental Protection Agency

ESG: Eastern Shore Gas Company and its affiliates

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

FASB: Financial Accounting Standards Board

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

FDEP: Florida Department of Environmental Protection

FDOT: Florida Department of Transportation

FGT: Florida Gas Transmission Company

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

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

Fort Meade: Fort Meade natural gas division of FPU

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

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

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

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

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

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

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

GSR: Gas Service Rates

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

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

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

ICE: Intercontinental Exchange is an electronic trading platform

IGC: Indiantown Gas Company, a division of FPU

IRS: *Internal Revenue Service*

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

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

MDE: Maryland Department of Environment

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

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

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

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

MTM: Fair value (mark-to-market) accounting required for derivatives in accordance with ASC 815

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

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

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

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

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

NYSE: *New York Stock Exchange*

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

OTC: Over-the-counter

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

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

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

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

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

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

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

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

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

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

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

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

Revolver: Our unsecured revolving credit facility with the Lenders

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

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

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

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

SEC: Securities and Exchange Commission

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

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

Sharpgas: Sharpgas, Inc., a subsidiary of Sharp

SICP: 2013 Stock and Incentive Compensation Plan

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

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

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

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

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

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

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

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

PART I

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

Safe Harbor for Forward-Looking Statements

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

- state and federal legislative and regulatory initiatives (including deregulation) that affect cost and investment recovery, have an impact on rate structures, and affect the speed and the degree to which competition enters the electric and natural gas industries;
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recoverable in rates;
- the impact of significant changes to current tax regulations and rates;
- the timing of certification authorizations associated with new capital projects;
- the ability to construct facilities at or below estimated costs;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now, or may in the future, own or operate;
- possible increased federal, state and local regulation of the safety of our operations;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- long-term global climate change, which could adversely affect customer demand or cause extreme weather conditions that disrupt the Company's operations;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- customers' preferred energy sources;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the effect of competition on our businesses;
- the timing and extent of changes in commodity prices and interest rates;
- the ability to establish new, and maintain key, supply sources;
- the effect of spot, forward and future market prices on our various energy businesses;
- the extent of our success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the capital-intensive nature of our regulated energy businesses;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger; acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the impact on our costs and funding obligations, under our pension and other post-retirement benefit plans, of potential downturns in the financial markets, lower discount rates, and costs associated with the Patient Protection and Affordable Care Act;
- the ability to continue to hire, train and retain appropriately qualified personnel;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- the timing and success of technological improvements; and
- risks related to cyber-attacks or cyber-terrorism that could disrupt our business operations or result in failure of information technology systems.

ITEM 1. BUSINESS.

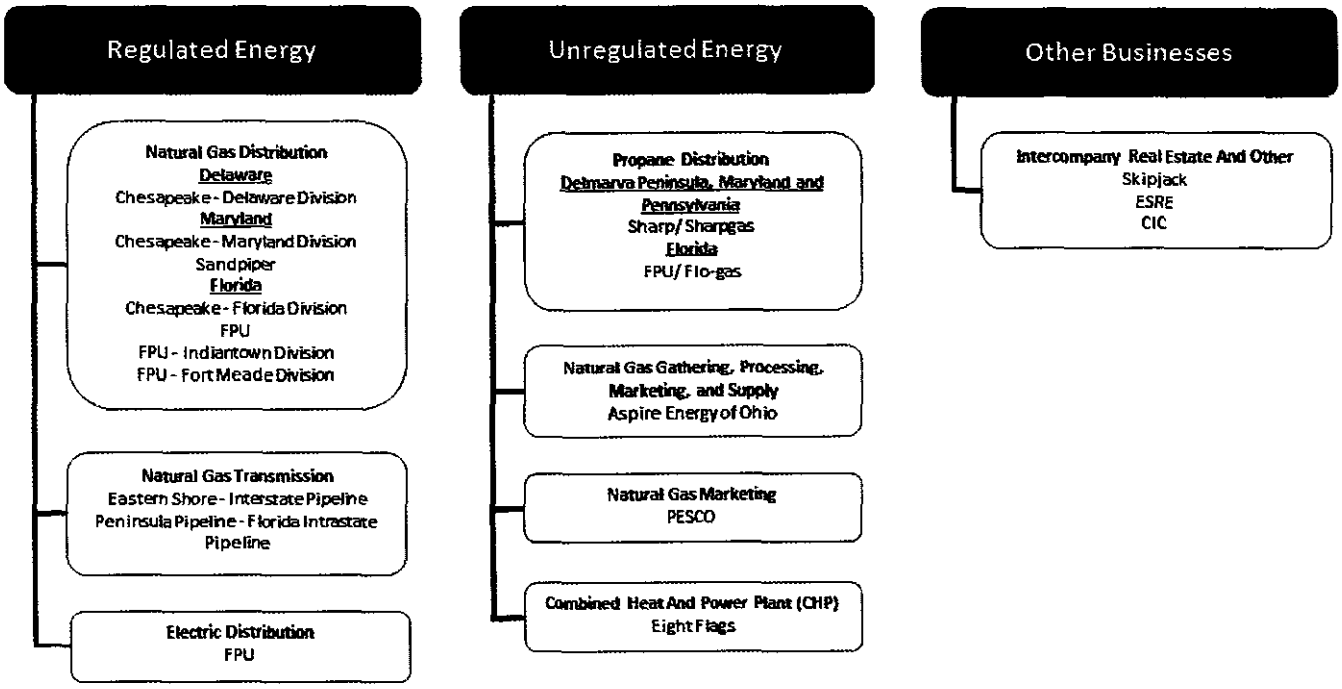
CORPORATE OVERVIEW

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

OPERATING SEGMENTS

We operate within two reportable segments: Regulated Energy and Unregulated Energy. The remainder of our operations is presented as "Other businesses and eliminations."

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



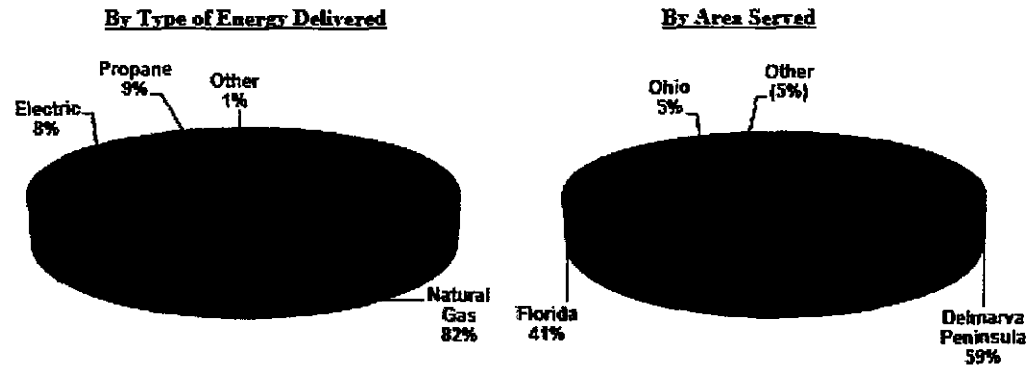
The following table shows operating income for the year ended December 31, 2017, and total assets as of December 31, 2017, for our operating segments and other businesses and eliminations:

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

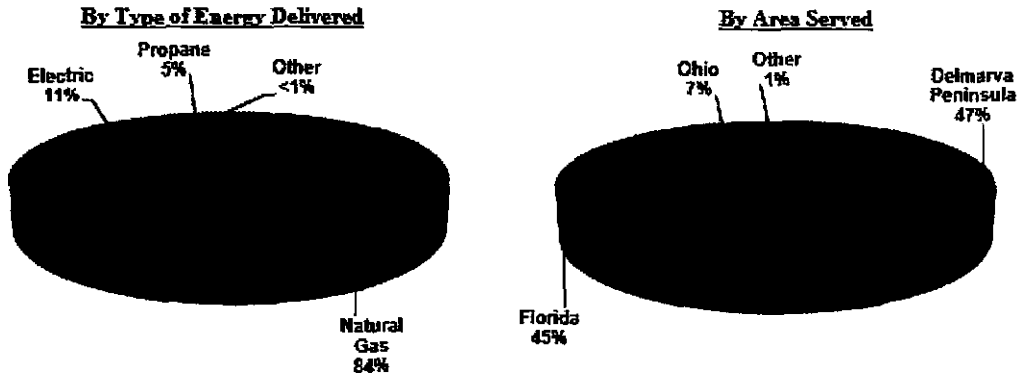
Additional financial information by business segment is set forth in *Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation,* and *Item 8, Financial Statements and Supplementary Data* (see Note 5, *Segment Information,* in the consolidated financial statements).

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

Operating Income by Energy Delivered and Area Served



Average Investment by Energy Delivered and Area Served [1]



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

REGULATED ENERGY

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

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

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

Operational Highlights

The following table presents operating revenues, volumes and the average number of customers by customer class for our natural gas and electric distribution operations for the year ended December 31, 2017:

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

[1] Operating Revenues from "Other" sources include unbilled revenue, under (over) recoveries of fuel cost, conservation revenue, other miscellaneous charges, fees for billing services provided to third parties, and adjustments for pass-through taxes.
[2] Florida natural gas distribution includes Chesapeake Utilities' Florida Division, FPU and FPU's Indiantown and Fort Meade divisions.
[3] Average number of customers is based on twelve-month average for the year ended December 31, 2017.

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

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

[1] Eastern Shore's service to our local distribution affiliates is based on FERC-approved rates and is an integral component of the cost associated with providing natural gas supplies for those affiliates. We eliminate operating revenues of Eastern Shore against the cost of sales of those affiliates in our consolidated financial information; however, our local distribution affiliates include this amount in their purchased fuel cost and recover it through fuel cost recovery mechanisms.
[2] Operating revenues from "Other" sources are from the rental of gas properties and reserve for rate case refund.

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

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

Weather

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

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

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

Regulatory Matters

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

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

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

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

[3] Allowed after-tax return on equity.

[4] The terms of the settlement agreement for the FPU electric division limited proceeding with the Florida PSC prescribed an authorized return on equity range of 9.25 to 11.25 percent, with a mid-point of 10.25 percent. The FPU electric division cannot file for a base rate increase prior to December 2019, unless its allowed return on equity is below the authorized range and it experiences an unanticipated and unforeseen event that impacts the annual revenue requirement in excess of $800,000 within any contiguous four-month period.

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

[6] The table reflects rate increases and rates of return approved prior to the enactment of the TCJA on December 22, 2017. See *Item 8, Financial Statements and Supplementary Data* (Note 18, *Rates and Other Regulatory Activities* and Note 11, *Income Taxes* in the consolidated financial statements) for further discussion on the impact of this legislation on our regulated businesses.

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

In addition to the base rates approved by the PSCs, certain of our local distribution utilities have additional surcharge mechanisms that were separately approved by their respective PSC. The most notable surcharge mechanisms include Delaware's surcharge to increase the

availability of natural gas in portions of eastern Sussex County, Delaware; Maryland's surcharge designed to recover the costs associated with conversions to natural gas and to improve infrastructure in Worcester County, Maryland; and Florida's GRIP surcharge designed to recover capital and other costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains.

TCJA

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

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

Competition

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

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

Supplies, Transmission and Storage

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

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

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

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

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

Sandpiper is a party to a capacity, supply and operating agreement with EGWIC to purchase propane, with a contract ending in May 2019. Sandpiper's current annual commitment is estimated at approximately 2.7 million gallons. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices. Sandpiper also has 1,950 Dts of maximum daily firm transportation capacity available from Eastern Shore through contracts expiring on various dates between 2018 and 2027.

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

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

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

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

Eastern Shore has three agreements with Transco for a total of 7,292 Dts/d of firm daily storage injection and withdrawal entitlements and total storage capacity of 288,003 Dts. These agreements expire on various dates between 2018 and 2023. Eastern Shore retains these firm storage services in order to provide swing transportation service and firm storage service to customers requesting such services.

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

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

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

UNREGULATED ENERGY

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

Propane Distribution

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

Propane Distribution - Operational Highlights

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

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

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

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

Propane Distribution - Competition

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

Propane Distribution - Supplies, Transportation and Storage

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

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

Propane Distribution Weather

Revenues from our propane distribution sales activities are affected by seasonal variations in temperature and weather conditions. Weather conditions and their severity directly influence the volume of propane used by our metered customers or sold and delivered to our bulk customers, with demand increasing substantially during the winter months when propane is used for heating. Sustained warmer-than-normal temperatures will tend to reduce propane use, while sustained colder-than-normal temperatures will tend to increase consumption.

Propane and Crude Oil Wholesale Marketing

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

Natural Gas Marketing

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

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

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

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

Unregulated Natural Gas Infrastructure Services

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

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

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

Eight Flags

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

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

OTHER BUSINESSES AND ELIMINATIONS

Overview

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

ENVIRONMENTAL COMPLIANCE

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

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

EMPLOYEES

As of December 31, 2017, we had a total of 945 employees, 118 of whom are union employees represented by two labor unions: the International Brotherhood of Electrical Workers and Commercial Workers Union. The collective bargaining agreements with these labor unions expire in 2019.

EXECUTIVE OFFICERS

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

Name	Age	Position
Michael P. McMasters	59	President (March 2010 - present) Chief Executive Officer (January 2011 - present) Director (March 2010 - present) Executive Vice President (September 2008 - February 2010) Chief Operating Officer (September 2008 - December 2010) Chief Financial Officer (January 1997 - September 2008) *Mr. McMasters also previously served as Senior Vice President, Vice President, Treasurer, Director of Accounting and Rates and Controller.*
Beth W. Cooper	51	Senior Vice President (September 2008 - present) Chief Financial Officer (September 2008 - present) Assistant Secretary (March 2015-present) Corporate Secretary (June 2005 - March 2015) Vice President (June 2005 - September 2008) Treasurer (March 2003 - May 2012) *Ms. Cooper also previously served as Assistant Vice President, Assistant Treasurer, Director of Internal Audit and Director of Strategic Planning.*
Elaine B. Bittner	48	Senior Vice President of Strategic Development (May 2013 - present) Chief Operating Officer - Sharp, Aspire Energy and PESCO (May 2014 - Present) Vice President of Strategic Development (June 2010 - May 2013) Vice President, Eastern Shore (May 2005 - June 2010) *Ms. Bittner also previously served as Director of Eastern Shore, Director of Customer Services and Regulatory Affairs for Eastern Shore and Director of Environmental Affairs and Environmental Engineer.*
Stephen C. Thompson	57	Senior Vice President (September 2004 - present) President, Eastern Shore (January 1997 - present) President and Chief Operating Officer, Sandpiper (May 2014 - present) Vice President (May 1997 - September 2004) *Mr. Thompson also previously served as Director of Gas Supply and Marketing for Eastern Shore, Superintendent of Eastern Shore and Regional Manager for Florida distribution operations.*
Jeffry M. Householder	60	President of Florida Public Utilities Company (June 2010 - present) *Prior to joining Chesapeake Utilities, Mr. Householder operated a consulting practice that provided business development and regulatory services to utilities, propane retailers and industrial clients.*
James F. Moriarty	60	Senior Vice President (February 2017 - present) General Counsel & Corporate Secretary (March 2015 - present) Vice President (March 2015 - February 2017) *Prior to joining Chesapeake Utilities, Mr. Moriarty was a Partner at Locke Lord LLP and Fulbright & Jaworski, LLP, both international law firms with offices in Washington, D.C.*

AVAILABLE INFORMATION AND CORPORATE GOVERNANCE DOCUMENTS

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

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

- Business Code of Ethics and Conduct applicable to all employees, officers and directors;

- Code of Ethics for Financial Officers;
- Corporate Governance Guidelines;
- Charters for the Audit Committee, Compensation Committee, Investment Committee, and Corporate Governance Committee of the Board of Directors; and
- Corporate Governance Guidelines on Director Independence.

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

CERTIFICATION TO THE NYSE

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

ITEM 1A. RISK FACTORS.

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

FINANCIAL RISKS

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

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

In addition, our ability to obtain adequate and cost-effective capital depends on our credit ratings, which are greatly affected by our financial performance and the liquidity of financial markets. A downgrade in our current credit ratings could adversely affect our access to capital markets, as well as our cost of capital. If we are not able to access capital at competitive rates, our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth may be limited.

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

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

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

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

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

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

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

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

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

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

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

An increase in interest rates, without the recovery of the higher cost of debt in the sales and/or transportation rates we charge our utility customers, could adversely affect future earnings. An increase in short-term interest rates could negatively affect our results of operations, which depend on short-term lines of credit to finance accounts receivable and storage gas inventories and to temporarily finance capital expenditures. Reference should be made to *Item 7A, Quantitative and Qualitative Disclosures About Market Risk* for additional information.

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

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

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

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

provisional amounts that we have recorded that may materially impact our provision for income taxes in the period in which adjustments are made.

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

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

Our stock price is subject to volatility.

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

OPERATIONAL RISKS

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

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

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

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

Electric. While there is active wholesale power sales competition in Florida, our retail electric business through FPU has remained substantially free from direct competition from other electric service providers. Generally, however, our retail electric business through FPU remains subject to competition from other energy sources. Changes in the competitive environment caused by legislation, regulation, market conditions, or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect our results of operations, cash flows and financial condition.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

addition, falling propane prices may result in inventory write-downs, as required by GAAP, if the market price of propane falls below our weighted average cost of inventory, which could adversely affect net income.

REGULATORY, LEGAL AND ENVIRONMENTAL RISKS

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

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

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

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

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

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

Costs of compliance with environmental laws may be significant.

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

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

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

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

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

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

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

There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The adoption of this type of legislation by Congress, or similar legislation by states, or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas and propane or impact the prices we charge to our customers. The direction of future U.S. climate change regulation is difficult to predict given the current uncertainties surrounding the policies of the Trump Administration. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions. Even if federal efforts in this area slow, states may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our products. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Key Properties

We own approximately 1,517 miles of natural gas distribution mains (together with related service lines, meters and regulators) located in Kent, New Castle and Sussex Counties, Delaware; and Caroline, Cecil, Dorchester, Wicomico and Worcester Counties, Maryland. We own approximately 2,906 miles of natural gas distribution mains (and related equipment) in Broward, Citrus, DeSoto, Gadsden, Gilchrist, Hillsborough, Holmes, Jackson, Liberty, Marion, Martin, Nassau, Osceola, Palm Beach, Pasco, Polk, Seminole, Suwannee, Union, Volusia and Washington Counties, Florida. In addition, we have adequate gate stations to handle receipt of the gas into each of the distribution systems. We also own facilities in Delaware and Maryland, which we use for propane-air injection during periods of peak demand.

Through Eastern Shore, we own and operate approximately 457 miles of natural gas transmission pipeline, extending from supply interconnects at Daleville, Honey Brook and Parkesburg, Pennsylvania; and Hockessin, Delaware, to 96 delivery points in southeastern Pennsylvania, Delaware and the eastern shore of Maryland. Through Peninsula Pipeline, we own and operate approximately 44 miles of natural gas transmission pipeline in Indian River, Palm Beach, Polk and Suwannee Counties, Florida. We also own approximately 45 percent of the 16-mile natural gas pipeline extending from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. The remaining 55 percent of the natural gas pipeline is owned by Peoples Gas.

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

We own approximately 338 miles of underground propane distribution mains in Delaware; Dorchester, Princess Anne, Queen Anne's, Somerset, Talbot, Wicomico and Worcester Counties, Maryland; Chester and Delaware Counties, Pennsylvania; and Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Marion, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

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

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

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

All of the assets owned by FPU are subject to a lien in favor of the holders of its first mortgage bond securing its indebtedness under its Mortgage Indenture and Deed of Trust. These assets are not subject to any other lien as all other debt is unsecured. FPU owns offices and facilities in the following locations: Alachua, Brevard, Broward, Hendry, Jackson, Levy, Martin, Nassau, Okeechobee, Palm Beach and Volusia Counties, Florida. The FPU assets subject to the lien also include: 1,970 miles of natural gas distribution mains (and related equipment) in its service areas; 20 miles of electric transmission line located in Nassau County, Florida; 896 miles of electric distribution line located in Calhoun, Jackson, Liberty and Nassau Counties in Florida; propane storage facilities with a total capacity of 1.2 million gallons, located in south and central Florida; and 83 miles of underground propane distribution mains in Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Marion, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

ITEM 3. LEGAL PROCEEDINGS.

LEGAL PROCEEDINGS

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

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

COMMON STOCK PRICE RANGES, COMMON STOCK DIVIDENDS AND STOCKHOLDER INFORMATION:

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

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
2017					
	March 31	**$ 70.70**	**$ 63.00**	**$ 69.20**	**$ 0.3050**
	June 30	**$ 77.75**	**$ 68.65**	**$ 74.95**	**$ 0.3250**
	September 30	**$ 81.95**	**$ 74.80**	**$ 78.25**	**$ 0.3250**
	December 31	**$ 86.35**	**$ 75.00**	**$ 78.55**	**$ 0.3250**
2016					
	March 31	$ 67.36	$ 52.25	$ 62.97	$ 0.2875
	June 30	$ 66.19	$ 56.56	$ 66.18	$ 0.3050
	September 30	$ 67.88	$ 59.12	$ 61.06	$ 0.3050
	December 31	$ 70.00	$ 57.63	$ 66.95	$ 0.3050

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

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

FPU's first mortgage bonds, which are due in 2022, contain a similar restriction that limits the payment of dividends by FPU. Refer to *Item 8, Financial Statements and Supplementary Data* (see Note 12, *Long-Term Debt,* in the consolidated financial statements) for additional information.

PURCHASES OF EQUITY SECURITIES BY THE ISSUER

The following table sets forth information on purchases by us or on our behalf of shares of our common stock during the quarter ended December 31, 2017.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
October 1, 2017 through October 31, 2017 [1]	373	$ 78.90	—	—
November 1, 2017 through November 30, 2017	—	—	—	—
December 1, 2017 through December 31, 2017	—	—	—	—
Total	373	$ 78.90	—	—

[1] In October 2017, we purchased shares of common stock on the open market for the purpose of reinvesting the dividend on shares held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Non-Qualified Deferred Compensation Plan. The Non-Qualified Deferred Compensation Plan is discussed in detail in *Item 8, Financial Statements and Supplementary Data* (see Note 16, *Employee Benefit Plans*, in the consolidated financial statements). During the quarter, 373 shares were purchased through the reinvestment of dividends.

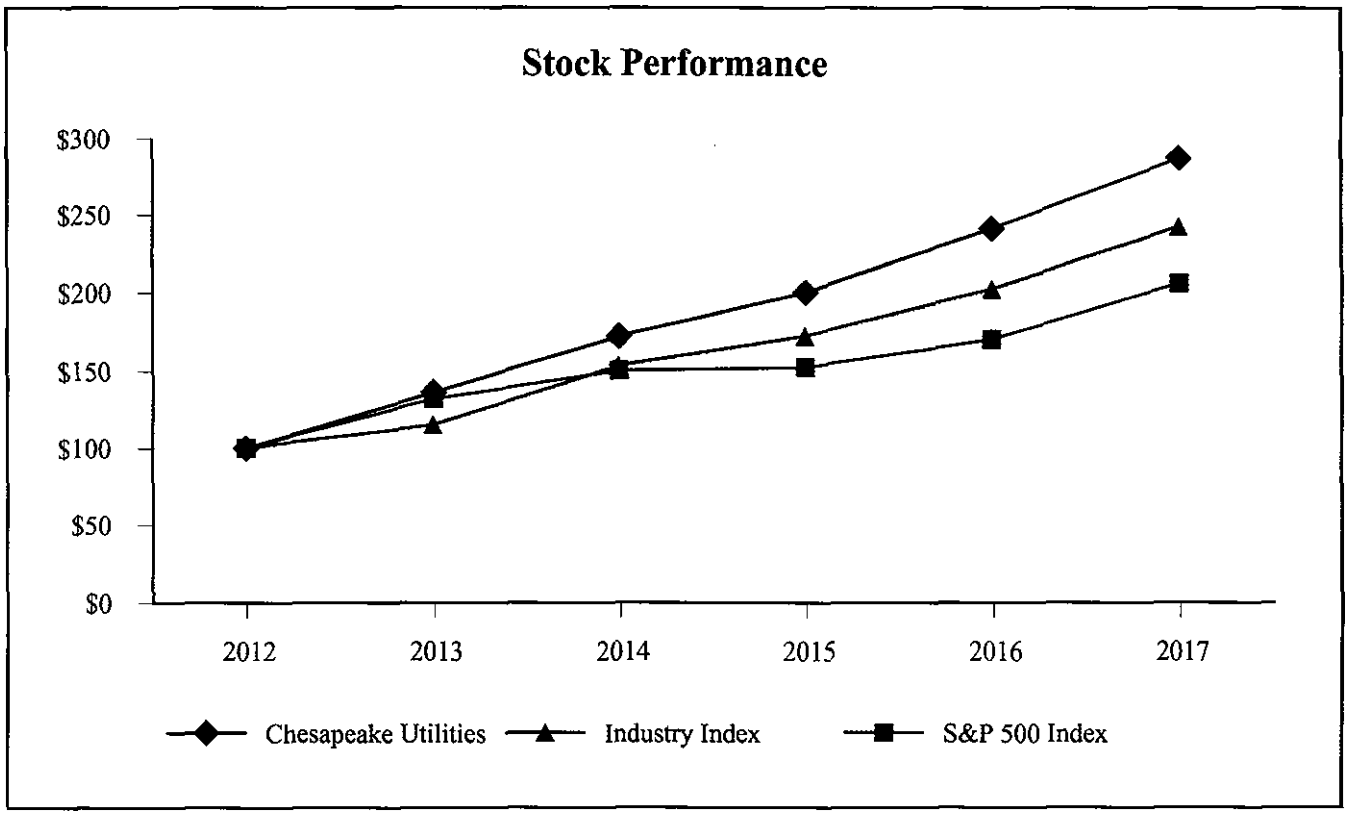
[2] Except for the purpose described in footnote [1], we have no publicly announced plans or programs to repurchase our shares.

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

COMMON STOCK PERFORMANCE GRAPH

The stock performance graph and table below compares cumulative total stockholder return on our common stock during the five fiscal years ended December 31, 2017, with the cumulative total stockholder return of the S&P 500 Index and the cumulative total stockholder return of select peers, which include the following companies: Atmos Energy Corporation; Chesapeake Utilities Corporation; Black Hills Corporation; New Jersey Resources Corporation; NiSource, Inc.; Northwest Natural Gas Company; Northwestern Corporation; RGC Resources, Inc.; South Jersey Industries, Inc.; Spire, Inc.; Unitil Corporation; Vectren Corporation; and WGL Holdings, Inc.

The comparison assumes $100 was invested on December 31, 2012 in our common stock and in each of the foregoing indices and assumes reinvested dividends. The comparisons in the graph below are based on historical data and are not intended to forecast the possible future performance of our common stock.



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

ITEM 6. SELECTED FINANCIAL DATA

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

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

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

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

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

(2) Shares and per share amounts for all periods presented reflect the three-for-two stock split declared on July 2, 2014, effected in the form of a stock dividend, and distributed on September 8, 2014.

(3) Dividend yield (annualized) is calculated by multiplying the fourth quarter dividend by four (4), then dividing that amount by the closing common stock price at December 31.

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

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

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

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

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

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

INTRODUCTION

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

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

The key elements of this strategy include:

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

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

OVERVIEW AND HIGHLIGHTS

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

2017 compared to 2016

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

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2016 Reported Results	$ 73,016	$ 44,675	$ 2.86
Adjusting for unusual items:			
Federal tax reform impact	—	14,299	0.87
PESCO - unrealized MTM loss	(5,783)	(3,499)	(0.21)
Impact of winding down of Xeron operations and absence of 2016 loss	745	451	0.03
Weather impact	578	350	0.02
	(4,460)	11,601	0.71
Increased (Decreased) Gross Margins:			
Eight Flags' CHP plant	4,901	2,965	0.19
Implementation of new base rates for Eastern Shore*	3,693	2,234	0.14
PESCO - margin from operations	3,365	2,036	0.13
Natural gas growth (excluding service expansions)	2,818	1,705	0.11
Service expansions*	2,062	1,248	0.08
GRIP*	1,902	1,151	0.07
Aspire Energy rates and management fees	1,125	680	0.04
Customer consumption (non-weather)	721	436	0.03
Implementation of Delaware Division settled rates	831	503	0.03
Wholesale propane sales and margins	678	410	0.03
Retail propane margins	645	390	0.02
Sandpiper SIR	291	176	0.01
	23,032	13,934	0.88
(Increased) Decreased Other Operating Expenses:			
Higher payroll expense	(6,487)	(3,925)	(0.25)
Higher depreciation, asset removal and property tax costs due to new capital investments	(5,120)	(3,098)	(0.20)
Eight Flags' operating expenses	(2,920)	(1,767)	(0.11)
Higher benefit and other employee-related expenses	(1,485)	(899)	(0.06)
Higher regulatory expenses associated with rate filings	(1,005)	(608)	(0.04)
Higher taxes other than property and income	(739)	(447)	(0.03)
Lower credit, collections & customer service expenses	515	311	0.02
Lower outside services and facilities maintenance costs	417	252	0.02
Higher vehicle expenses	(372)	(225)	(0.01)
Higher sales and advertising expenses	(259)	(157)	(0.01)
	(17,455)	(10,563)	(0.67)
Increase in outstanding shares from the September 2016 public offering	—	—	(0.16)
Interest charges	(2,006)	(1,214)	(0.08)
Change in other expense	(191)	(115)	(0.01)
Change in effective tax rate prior to tax reform	—	(500)	(0.03)
Net other changes	497	306	0.05
Year ended December 31, 2017 Reported Results	**$ 72,433**	**$ 58,124**	**$ 3.55**

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

2016 compared to 2015

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

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

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

SUMMARY OF KEY FACTORS

Major Projects and Initiatives

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

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

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

Major Projects and Initiatives Recently Completed

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

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

Service Expansions

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

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

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

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

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

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

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

Regulatory Proceedings

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

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

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

Major Projects and Initiatives Currently Underway

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

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

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

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

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

Weather and Consumption

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

HDD and CDD Information

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

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

Propane Results

Our Florida and Delmarva Peninsula propane distribution operations continue to pursue a multi-pronged growth strategy, which includes targeting retail and wholesale customer growth in existing markets, both organically as well as through acquisitions; incremental growth from recent and planned start-ups in new markets, targeting new community gas systems in high growth areas; further build-out of our propane vehicular platform through AutoGas fueling stations; and optimization of our supply portfolio to generate incremental margin opportunities. Over the years, we have focused on meeting customer energy demand, and we have created a portfolio of offerings regardless of whether the customer is served via a pipeline or through an individual tank. AutoGas is our most recent offering that meets customers' varying demands.

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

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

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

PESCO

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

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

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

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

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

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

Xeron

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

Positioning the Company for Future Growth

Resource Allocation

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

Financing the Growth

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

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

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

REGULATED ENERGY

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

2017 compared to 2016

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

Gross Margin

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

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

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

Implementation of Eastern Shore Rates

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

Natural Gas Growth (Excluding Service Expansions)

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

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

Service Expansions

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

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

Additional Revenue from GRIP in Florida

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

Implementation of Delaware Division Rates

Our Delaware Division generated additional gross margin of $831,000 as a result of its rate case settlement. See *Note 18, Rates and Other Regulatory Activities*, to the consolidated financial statements for additional details.

Service to Eight Flags

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

Other Operating Expenses

Other operating expenses increased by $8.2 million. The significant components of the increase in other operating expenses included:

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

2016 compared to 2015

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

Gross Margin

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

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

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

Service Expansions

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

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

Additional Revenue from GRIP in Florida

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

Natural Gas Growth (excluding service expansions)

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

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

Implementation of Delaware Division Rates

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

Service to Eight Flags

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

Sandpiper SIR

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

Operating Expenses

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

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

UNREGULATED ENERGY

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

2017 Compared to 2016

Operating income for the Unregulated Energy segment for 2017 was $12.5 million, a decrease of $1.4 million compared to 2016. The decreased operating income was due to an increase in gross margin of $7.6 million, which was offset by an increase of $9.0 million in operating expenses. Gross margin and operating income, excluding the impact of the unrealized MTM loss on energy-related derivatives, grew by $13.4 million, or 20.6 percent, and $4.4 million, or 31.9 percent, respectively, during 2017 compared to 2016.

Gross Margin

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

(in thousands)	
Gross margin for the year ended December 31, 2016	$ 64,962
Factors contributing to the gross margin increase for the year ended December 31, 2017:	
PESCO - unrealized MTM loss	(5,783)
Eight Flags' CHP plant	4,365
PESCO - margin from operations	3,365
Customer consumption - weather and other	2,144
Pricing amendments to Aspire Energy's long-term agreements	1,125
Higher wholesale propane sales and margins	678
Wind-down of Xeron operations	658
Improved retail propane margins	645
Other	413
Gross margin for the year ended December 31, 2017	$ 72,572

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

Eight Flags

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

Natural Gas Marketing - PESCO

PESCO's gross margin decreased by $2.4 million due primarily to:

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

Customer Consumption - Weather and Other

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

Pricing Amendments to Aspire Energy's Long-Term Agreements

An increase in gross margin of $1.1 million due to favorable pricing amendments to several long-term sales agreements.

Wholesale Propane Sales and Margins

Gross margin increased by $678,000, due primarily to increased volumes and favorable supply management activities for the Delmarva Peninsula propane distribution operations, as well as higher throughput margins in Florida. Growth of the wholesale business is a component of our propane growth strategy.

Wind-down of Xeron operations

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

Retail Propane Margins

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

Other Operating Expenses

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

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

2016 Compared to 2015

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

Gross Margin

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

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

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

Aspire Energy

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

Eight Flags' CHP Plant

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

Decreased Retail Propane Margins

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

Decreased Customer Consumption - Weather and Other

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

Natural Gas Marketing - PESCO

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

Lower Margins for Xeron

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

Operating Expenses

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

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

OTHER INCOME (EXPENSE)

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

INTEREST EXPENSE

2017 Compared to 2016

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

2016 Compared to 2015

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

INCOME TAXES

2017 Compared to 2016

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

2016 Compared to 2015

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

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

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

The 2018 budget, excluding acquisitions, includes the remaining capital expenditures associated with Eastern Shore's 2017 System Expansion Project; Florida's Northwest Florida Expansion Project; additional expansions of our natural gas distribution and transmission systems; continued natural gas infrastructure improvement activities; expenditures for continued replacement under the Florida GRIP; information technology systems; new buildings and facilities; and other strategic initiatives and investments.

The capital expenditure projection is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts. On average, over the last five years, our actual capital expenditures have averaged 91 percent of the initial budgeted capital expenditures for those years.

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

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated energy operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors.

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

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

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

Included in the long-term debt balances at December 31, 2017, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($620,000 excluding current maturities and $2.1 million including current maturities). At the

closing of the ESG acquisition in May 2013, Sandpiper entered into this agreement, which has a six-year term. The capacity portion of this agreement is accounted for as a capital lease.

As of December 31, 2017, we did not have any restrictions on our cash balances. Chesapeake Utilities' Senior Notes and FPU's first mortgage bonds contain a restriction that limits the payment of dividends or other restricted payments in excess of certain pre-determined thresholds. As of December 31, 2017, $209.7 million of Chesapeake Utilities' cumulative consolidated net income and $104.9 million of FPU's cumulative net income were free of such restrictions.

Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. We have maintained a ratio of equity to total capitalization, including short-term borrowings, between 50 percent and 56 percent during the past three years. In September 2016, we completed a public offering of 960,488 shares of our common stock at a public offering price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 million, which were added to our general funds and used to repay a portion of our short-term debt under unsecured lines of credit. Our equity to total capitalization ratio, including short-term borrowings, was 52 percent as of December 31, 2017.

As described below under "Short-Term Borrowings," we entered into the Credit Agreement and the Revolver with the Lenders in October 2015, which increased our borrowing capacity by $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we also entered into long-term shelf agreements for the potential private placement of unsecured senior debt as further described below under the heading "Shelf Agreements."

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

Shelf Agreements

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

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

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

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

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

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

Short-Term Borrowings

Our outstanding short-term borrowings at December 31, 2017 and 2016 were $251.0 million and $209.9 million, respectively, at weighted average interest rates of 2.42 percent and 1.43 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. In November 2017, we entered into a new $40.0 million credit

facility with a new lender. As of December 31, 2017, we had five unsecured bank credit facilities with four financial institutions totaling $220.0 million in available credit. In addition, since October 2015, we have $150.0 million of additional short-term debt capacity available under the Revolver with five participating Lenders. The terms of the Revolver are described in further detail below. None of the unsecured bank lines of credit requires compensating balances. We are currently authorized by our Board of Directors to borrow up to $275.0 million of short-term borrowing. As of February 27, 2018 the Board increased this limit from $275.0 million to $350.0 million.

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

Our outstanding short-term borrowings at December 31, 2017 and 2016 included $10.3 million and $8.6 million, respectively, of book overdrafts. Book overdrafts are not actual borrowings under the credit facilities; however, these book overdrafts, if presented, would be funded through the credit facilities and, therefore, were included in the short-term borrowings.

As of December 31, 2017, we had issued $5.0 million in letters of credit to various counterparties under the Revolver. Although the letters of credit are not included in the outstanding short-term borrowings and we do not anticipate they will be drawn upon by the counterparties, the letters of credit reduce the available borrowings under the Revolver.

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

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

Cash Flows

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

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

Cash Flows Provided by Operating Activities

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

We normally generate a large portion of our annual net income and related increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas and propane delivered by our natural gas and propane distribution operations and our natural gas supply, gathering and processing operation to customers during the peak heating season.

In addition, our natural gas and propane inventories, which usually peak in the fall months, are largely drawn down in the heating season and provide a source of cash as the inventory is used to satisfy winter sales demand.

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

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

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

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

Cash Flows Used in Investing Activities

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

- Cash paid for capital expenditures increased by $5.4 million to $175.3 million for 2017, compared to $169.9 million in 2016.
- Net cash of $11.9 million was used to acquire assets in various transactions during 2017, including ARM, Chipola and Central Gas; there were no corresponding transactions in 2016.

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

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

Cash Flows Provided by Financing Activities

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

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

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

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

CONTRACTUAL OBLIGATIONS

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

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

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

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

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

(4) We have recorded long-term liabilities of $3.4 million at December 31, 2017 for unfunded post-employment and post-retirement benefit plans. The amounts specified in the table are based on expected payments to current retirees and assume a retirement age of 62 for currently active employees. There are many factors that would cause actual payments to differ from these amounts, including early retirement, future health care costs that differ from past experience and discount rates implicit in calculations. See *Item 8, Financial Statements and Supplementary Data,* Note 16, *Employee Benefit Plans,* for additional information on the plans.

(5) We have recorded long-term liabilities of $18.4 million at December 31, 2017 for two qualified, defined benefit pension plans. The assets funding these plans are in a separate trust and are not considered assets of ours or included in our balance sheets. The Contractual Obligations table above includes $1.9 million reflecting the payments we expect to make to the trust funds in 2017. Additional contributions may be required in future years based on the actual return earned by the plan assets and other actuarial assumptions, such as the discount rate and long-term expected rate of return on plan assets. See *Item 8, Financial Statements and Supplementary Data,* Note 16, *Employee Benefit Plans,* for further information on the plans. Additionally, the Contractual Obligations table above includes deferred compensation obligations totaling $6.7 million, funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the consolidated balance sheets. We assume a retirement age of 65 for purposes of distribution from this account.

OFF-BALANCE SHEET ARRANGEMENTS

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

We have issued letters of credit totaling $5.0 million related to the electric transmission services for FPU's northwest electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, and to our current and previous primary insurance carrier. These letters of credit have varying expiration dates extending through November 4, 2018. There were no draws on these letters of credit as of December 31, 2017. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future. Additional information is presented in *Item 8, Financial Statements and Supplementary Data,* Note 20, *Other Commitments and Contingencies* in the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

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

Regulatory Assets and Liabilities

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

Valuation of Environmental Liabilities and Related Regulatory Assets

As more fully described in Item 8, *Financial Statements and Supplementary Data,* Note 19, *Environmental Commitments and Contingencies*, in the consolidated financial statements, we are currently participating in the investigation, assessment or remediation of seven former MGP sites for which we have sought or will seek regulatory approval to recover through rates the estimated costs of remediation and related activities. Amounts have been recorded as environmental liabilities based on estimates of future costs to remediate these sites, which are provided by independent consultants.

Derivative Instruments

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

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

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

Additional information about our derivative instruments is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 7, *Derivative Instruments,* in the Consolidated Financial Statements.

Operating Revenues

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

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

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

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

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

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

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

Allowance for Doubtful Accounts

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

Goodwill and Other Intangible Assets

We test goodwill for impairment at least annually in December. The annual impairment testing for 2017 indicated no impairment of goodwill. Additional information is presented in Item 8, *Financial Statements and Supplementary Data,* Note 10, *Goodwill and Other Intangible Assets,* in the consolidated financial statements.

Other Assets Impairment Evaluations

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

Pension and Other Postretirement Benefits

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. The assumed discount rates and the expected returns on plan assets are the assumptions that generally have the most significant impact on the pension costs and liabilities. The assumed discount rates, the assumed health care cost trend rates and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. Additional information is presented in Item 8, *Financial Statements and Supplementary Data,* Note 16, *Employee Benefit Plans,* in the consolidated financial statements, including plan asset investment allocation, estimated future benefit payments, general descriptions of the plans, significant assumptions, the impact of certain changes in assumptions, and significant changes in estimates.

For 2017, actuarial assumptions include expected long-term rates of return on plan assets of 6.00 percent and 6.50 percent for Chesapeake Utilities' pension plan and FPU's pension plan, respectively, and discount rates of 3.50 percent and 3.75 percent for Chesapeake Utilities' and FPU's plans, respectively. The discount rate for each plan was determined by management considering high-quality corporate bond rates, such as the Prudential curve index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected lives of the plans and the availability of the lump-sum payment option. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately $7,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $9,000.

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

Tax-Related Contingency

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

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

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

INTEREST RATE RISK

Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt at December 31, 2017 consists of fixed-rate Senior Notes and $8.0 million of fixed-rate secured debt. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowings based in part on the fluctuation in interest rates. Additional information about our long-term debt is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 12, *Long-term Debt,* in the consolidated financial statements.

COMMODITY PRICE RISK

Regulated Energy Segment

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

Unregulated Energy Segment

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

We can store up to approximately 6.8 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate the risk of propane commodity price fluctuations on the inventory valuation, we have adopted a Risk Management Policy that allows our propane distribution operation to enter into fair value hedges, cash flows hedges or other economic hedges of our inventory.

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

PESCO is a party to natural gas swap and futures contracts. These contracts provide PESCO with the right to purchase natural gas at a fixed price at future dates. Upon expiration, the contracts can be settled financially without taking delivery of natural gas, or PESCO can procure natural gas for its customers.

PESCO is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids and natural gas deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts.

The following table reflects the changes in the fair market value of financial derivatives contracts related to natural gas and propane purchases and sales from December 31, 2016 to December 31, 2017:

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

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

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

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

WHOLESALE CREDIT RISK

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

Additional information about our derivative instruments is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 7, *Derivative Instruments,* in the Consolidated Financial Statements.

INFLATION

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. While the impact of inflation has remained low in recent years, natural gas and propane prices are subject to rapid fluctuations. In the regulated natural gas and electric distribution operations, fluctuations in natural gas and electricity prices are passed on to customers through the fuel cost recovery mechanism in our tariffs. To help cope with the effects of inflation on our capital investments and returns, we periodically seek rate increases from regulatory commissions for our regulated operations and closely monitor the returns of our unregulated energy business operations. To compensate for fluctuations in propane gas prices, we adjust propane sales prices to the extent allowed by the market.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation

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

We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation and Subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement schedule listed in Item 15(a)2 (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework: (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework: (2013)* issued by COSO.

Basis for Opinion

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Baker Tilly Virchow Krause, LLP

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

Philadelphia, Pennsylvania
February 28, 2018

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Income

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

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Comprehensive Income

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

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

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

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

	As of December 31,	
Capitalization and Liabilities	**2017**	**2016**
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Preferred stock, par value $0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	$ —	$ —
Common stock, par value $0.4867 per share (authorized 50,000,000 shares)	**7,955**	7,935
Additional paid-in capital	**253,470**	250,967
Retained earnings	**229,141**	192,062
Accumulated other comprehensive loss	**(4,272)**	(4,878)
Deferred compensation obligation	**3,395**	2,416
Treasury stock	**(3,395)**	(2,416)
Total stockholders' equity	**486,294**	446,086
Long-term debt, net of current maturities	**197,395**	136,954
Total capitalization	**683,689**	583,040
Current Liabilities		
Current portion of long-term debt	**9,421**	12,099
Short-term borrowing	**250,969**	209,871
Accounts payable	**74,688**	56,935
Customer deposits and refunds	**34,751**	29,238
Accrued interest	**1,742**	1,312
Dividends payable	**5,312**	4,973
Accrued compensation	**13,112**	10,496
Regulatory liabilities	**6,485**	1,291
Derivative liabilities, at fair value	**6,247**	773
Other accrued liabilities	**10,273**	7,063
Total current liabilities	**413,000**	334,051
Deferred Credits and Other Liabilities		
Deferred income taxes	**135,850**	222,894
Regulatory liabilities	**140,978**	43,064
Environmental liabilities	**8,263**	8,592
Other pension and benefit costs	**29,699**	32,828
Deferred investment tax credits and other liabilities	**5,955**	4,750
Total deferred credits and other liabilities	**320,745**	312,128
Environmental and other commitments and contingencies (Note 19 and 20)		
Total Capitalization and Liabilities	**$ 1,417,434**	$ 1,229,219

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Cash Flows

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

Supplemental Cash Flow Disclosures (see Note 6)

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

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Stockholders' Equity

(in thousands, except shares and per share data)	Common Stock [1] Number of Shares[2]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2014	**14,588,711**	**$ 7,100**	**$ 156,581**	**$ 142,317**	**$ (5,676)**	**$ 1,258**	**$ (1,258)**	**$ 300,322**
Net Income	—	—	—	41,140	—	—	—	**41,140**
Other comprehensive loss	—	—	—	—	(164)	—	—	**(164)**
Dividends declared ($1.1325 per share)	—	—	—	(17,222)	—	—	—	**(17,222)**
Retirement savings plan and dividend reinvestment plan	43,275	21	2,214	—	—	—	—	**2,235**
Common stock issued in acquisition	592,970	289	29,876	—	—	—	—	**30,165**
Share-based compensation and tax benefit [4][5]	45,703	22	1,640	—	—	—	—	**1,662**
Treasury stock activities[2]	—	—	—	—	—	625	(625)	—
Balance at December 31, 2015	**15,270,659**	**7,432**	**190,311**	**166,235**	**(5,840)**	**1,883**	**(1,883)**	**358,138**
Net Income	—	—	—	44,675	—	—	—	**44,675**
Other comprehensive income	—	—	—	—	962	—	—	**962**
Dividends declared ($1.2025 per share)	—	—	—	(18,848)	—	—	—	**(18,848)**
Retirement savings plan and dividend reinvestment plan	36,253	17	2,225	—	—	—	—	**2,242**
Stock issuance [3]	960,488	467	56,893	—	—	—	—	**57,360**
Share-based compensation and tax benefit [4][5]	36,099	19	1,538	—	—	—	—	**1,557**
Treasury stock activities[2]	—	—	—	—	—	533	(533)	—
Balance at December 31, 2016	**16,303,499**	**7,935**	**250,967**	**192,062**	**(4,878)**	**2,416**	**(2,416)**	**446,086**
Net Income	—	—	—	58,124	—	—	—	**58,124**
Other comprehensive income	—	—	—	—	606	—	—	**606**
Dividends declared ($1.2800 per share)	—	—	—	(21,045)	—	—	—	**(21,045)**
Dividend reinvestment plan	10,771	5	730	—	—	—	—	**735**
Stock issuance [3]	—	—	(10)	—	—	—	—	**(10)**
Share-based compensation and tax benefit [4][5]	30,172	15	1,783	—	—	—	—	**1,798**
Treasury stock activities[2]	—	—	—	—	—	979	(979)	—
Balance at December 31, 2017	**16,344,442**	**$ 7,955**	**$ 253,470**	**$ 229,141**	**$ (4,272)**	**$ 3,395**	**$ (3,395)**	**$ 486,294**

(1) 2,000,000 shares of preferred stock at $0.01 par value per share have been authorized. No shares have been issued or are outstanding; accordingly, no information has been included in the Statements of Stockholders' Equity.

(2) Includes 90,961, 76,745 and 70,631 shares at December 31, 2017, 2016 and 2015, respectively, held in a Rabbi Trust related to our Non-Qualified Deferred Compensation Plan.

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

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

(5) The shares issued under the SICP are net of shares withheld for employee taxes. For 2017, 2016 and 2015, we withheld 10,269, 12,031 and 12,620 shares, respectively, for taxes.

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

1. ORGANIZATION AND BASIS OF PRESENTATION

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

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

Our unregulated energy businesses primarily include: (a) propane distribution operations in Delaware, Maryland, the eastern shore of Virginia, southeastern Pennsylvania and Florida; (b) our natural gas marketing operation providing natural gas supplies directly to commercial and industrial customers in Florida, Delaware, Maryland, Ohio and other states; (c) our natural gas supply, gathering and processing operation in central and eastern Ohio; and (d) our CHP plant in Florida that generates electricity and steam.

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

We reclassified certain amounts in the consolidated statement of cash flows for the years ended December 31, 2016 and 2015 to conform to the current year's presentation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

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

Property, Plant and Equipment

Property, plant and equipment are stated at original cost less accumulated depreciation or fair value, if impaired. Costs include direct labor, materials and third-party construction contractor costs, AFUDC, and certain indirect costs related to equipment and employees engaged in construction. The costs of repairs and minor replacements are charged to expense as incurred, and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of property within the regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. Upon retirement or disposition of property owned by the unregulated businesses, the gain or loss, net of salvage value, is charged to income. A summary of property, plant and equipment by classification as of December 31, 2017 and 2016 is provided in the following table:

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

Contributions or Advances in Aid of Construction

Customer contributions or advances in aid of construction reduce property, plant and equipment, unless the amounts are refundable to customers. Contributions or advances may be refundable to customers after a number of years based on the amount of revenues generated from the customers or the duration of the service provided to the customers. Refundable contributions or advances are recorded initially as liabilities. The amounts that are determined to be non-refundable reduce property, plant and equipment at the time of such determination. During the years ended December 31, 2017, 2016 and 2015, there were $2.1 million, $1.0 million and $1.7 million, respectively, of non-refundable contributions or advances that reduced property, plant and equipment.

Allowance for Funds Used During Construction

Some of the additions to our regulated property, plant and equipment include AFUDC, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects. AFUDC is capitalized in the applicable rate base for rate making purposes when the completed projects are placed in service. During the years ended December 31, 2017, 2016 and 2015, AFUDC, which was reflected as a reduction of interest charges, was not material.

Assets Used in Leases

Property, plant and equipment for the Florida natural gas transmission operation included $1.4 million of assets, at December 31, 2017 and 2016, consisting primarily of mains, measuring equipment and regulation station equipment used by Peninsula Pipeline to provide natural gas transmission service pursuant to a contract with a third party. This contract is accounted for as an operating lease due to the exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and generates $264,000 in annual revenue for a 20-year term. Accumulated depreciation for these assets totaled $652,000 and $580,000 at December 31, 2017 and 2016, respectively.

Capital Lease Asset

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

Jointly-owned Pipeline

Property, plant and equipment for our Florida natural gas transmission operation also included $6.7 million of assets, at December 31, 2017 and 2016, which consists of the 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida, jointly owned by Peninsula Pipeline and Peoples Gas. The amount included in property, plant and equipment represents Peninsula Pipeline's 45-percent ownership of this pipeline. Each party was responsible for financing its portion of the jointly-owned pipeline. This 16-mile pipeline was placed in service in December 2012. Accumulated depreciation for this pipeline totaled $1.3 million and $1.0 million, at December 31, 2017 and 2016, respectively.

Asset Impairment Evaluations

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

In May 2015, we entered into a settlement agreement with a vendor related to the implementation of a customer billing system. Pursuant to the agreement, we received $1.5 million in cash, which is reflected as "Gain from a settlement" in the accompanying consolidated statements of income. In May 2016, we received an additional $650,000 in cash; however, retention of this amount is contingent upon engaging this vendor to provide agreed-upon services through May 2020.

Depreciation and Accretion Included in Operations Expenses

We compute depreciation expense for our regulated operations by applying composite, annual rates, as approved by the respective regulatory bodies. The following table shows the average depreciation rates used for regulated operations during the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Natural gas distribution – Delmarva Peninsula	2.5%	2.5%	2.4%
Natural gas distribution – Florida	2.9%	2.9%	2.9%
Natural gas transmission – Delmarva Peninsula	2.8%	2.7%	2.7%
Natural gas transmission – Florida	3.5%	3.9%	4.0%
Electric distribution – Florida	3.4%	3.5%	3.5%

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

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

We report certain depreciation and accretion in operations expense, rather than as a depreciation and amortization expense, in the accompanying consolidated statements of income in accordance with industry practice and regulatory requirements. Depreciation and accretion included in operations expense consists of the accretion of the costs of removal for future retirements of utility assets, vehicle depreciation, computer software and hardware depreciation, and other minor amounts of depreciation expense. For the years ended December 31, 2017, 2016 and 2015, we reported $8.1 million, $7.3 million and $7.0 million, respectively, of depreciation and accretion in operations expenses.

Regulated Operations

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

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

Revenue Recognition

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

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

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

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

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

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

All of our natural gas and electric distribution operations, except for two utilities that do not sell natural gas to end-use customers as a result of deregulation, have fuel cost recovery mechanisms. These mechanisms provide a method of adjusting the billing rates to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year. Chesapeake Utilities' Florida Division and FPU's Indiantown division provide unbundled delivery service to their customers, whereby the customers are permitted to purchase their gas requirements directly from competitive natural gas marketers.

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

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

Cost of Sales

Cost of sales includes the direct costs attributable to the products sold or services provided to our customers. These costs include primarily the variable cost of natural gas, electricity and propane commodities, pipeline capacity costs needed to transport and store natural gas, transmission costs for electricity, gathering and processing gas costs, transportation costs to transport propane purchases to our storage facilities, and steam and electricity generation costs. Depreciation expense is not included in our cost of sales.

Operations and Maintenance Expenses

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

Cash and Cash Equivalents

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

Accounts Receivable and Allowance for Doubtful Accounts

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

Inventories

We use the average cost method to value propane, materials and supplies, and other merchandise inventory. If market prices drop below cost, inventory balances that are subject to price risk are adjusted to their net realizable value. There was no lower-of-cost-or-net realizable value adjustment during 2017, 2016 or 2015.

Goodwill and Other Intangible Assets

Goodwill is not amortized but is tested for impairment at least annually. Goodwill of a reporting unit is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its implied fair value. The testing of goodwill for 2017, 2016 and 2015 indicated no goodwill impairment.

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

Other Deferred Charges

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

Asset Removal Cost

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

Pension and Other Postretirement Plans

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

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

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

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

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

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

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

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

We account for uncertainty in income taxes in our consolidated financial statements only if it is more likely than not that an uncertain tax position is sustainable based on technical merits. Recognizable tax positions are then measured to determine the

amount of benefit recognized in the consolidated financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

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

Financial Instruments

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

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

Our propane distribution operations enter into derivative transactions, such as swaps, put options and call options in order to mitigate the impact of wholesale price fluctuations on inventory valuation and future purchase commitments.

Our natural gas marketing operation enters into natural gas futures and swap contracts to mitigate any price risk associated with the purchase and/or sale of natural gas to specific customers.

These transactions may be designated as fair value hedges or cash flow hedges, if they meet all of the accounting requirements pursuant to ASC Topic 815, *Derivatives and Hedging,* and we elect to designate the instruments as hedges. If designated as a fair value hedge, the value of the hedging instrument, such as a swap, future, or put option, is recorded at fair value, with the effective portion of the gain or loss of the hedging instrument effectively reducing or increasing the value of the hedged item. If designated as a cash flow hedge, the value of the hedging instrument, such as a swap, call option or natural gas futures contract, is recorded at fair value with the effective portion of the gain or loss of the hedging instrument being recorded in comprehensive income. The ineffective portion of the gain or loss of a hedge is recorded in earnings. If the instrument is not designated as a fair value or cash flow hedge, or it does not meet the accounting requirements of a hedge under ASC Topic 815, Derivatives and Hedging, it is recorded at fair value with all gains or losses being recorded directly in earnings. In 2018, we will be adopting ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, the updated hedge accounting standard, which we expect will reduce the MTM volatility in PESCO's results due to better alignment of risk management activities and financial reporting, risk component hedging and certain other simplifications of hedge accounting guidance.

FASB Statements

Recently Adopted Accounting Standards

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

Recent Accounting Standards Yet to be Adopted

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

We have completed our evaluation of our revenue sources and the impact on our financial position, results of operations and cash flows. In tandem, we have developed and documented accounting policies and position papers, which are intended to meet the

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

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

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

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

Other practical expedients that can be elected individually are:

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

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

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

Statement of Cash Flows (ASC 230) - In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments*, which clarifies how certain transactions are classified in the statement of cash flows. ASU 2016-15 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. We believe that the implementation of this new standard will not have a material impact on our consolidated statement of cash flows.

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

Compensation-Retirement Benefits (ASC 715) - In March 2017, the FASB issued ASU 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post Retirement Benefit Cost.* Under this guidance, employers are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit costs are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update allows for capitalization of the service cost component when applicable. ASU 2017-07 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. The presentation of the service cost and other components in this update are to be applied retrospectively, and the capitalization of the service cost is to be applied prospectively

on or after the effective date. Aside from changes in presentation, we believe that the implementation of this new standard will not have a material impact on our financial position or results of operations.

Compensation - Stock Compensation (ASC 718) - In May 2017, the FASB issued ASU 2017-09, *Scope of Modification Accounting,* to clarify when to account for a change in the terms or conditions of a share-based payment award as a modification. Under this guidance, modification accounting is required only if the fair value, the vesting conditions or the award classification (equity or liability) changes as a result of a change in the terms or conditions of the award. The guidance is effective for our annual financial statements beginning January 1, 2018, although early adoption is permitted. The amendments included in this standard are to be applied prospectively. We believe that the implementation of this new standard will not have a material impact on our financial position or results of operations.

Derivatives and Hedging (ASC 815) - In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, to better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. Among other changes to hedge designation, ASU 2017-12 expands the risks that can be designated as hedged risks in cash flow hedges to include cash flow variability from contractually specified components of forecasted purchases or sales of non-financial assets. ASU 2017-12 requires the entire change in fair value of a hedging instrument included in the assessment of hedge effectiveness to be presented in the same income statement line that is used to present the earnings effects of the hedged item for fair value hedges and in other comprehensive income for cash flow hedges. For disclosures, ASU 2017-12 requires a tabular presentation of the income statement effect of fair value and cash flow hedges, and it eliminates the requirement to disclose the ineffective portion of the change in fair value of hedging instruments. ASU 2017-12 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. We are evaluating the effect of this standard on our future financial position and results of operations. In 2018, we will be adopting the updated hedge accounting standard, which we expect will reduce the MTM volatility in PESCO's results due to better alignment of risk management activities and financial reporting, risk component hedging and certain other simplifications of hedge accounting guidance.

Income Statement - Reporting Comprehensive Income (ASC 220) - In February 2018, the FASB issued ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA. ASU 2018-02 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. We are evaluating the effect of this standard on our future financial position and results of operations.

3. EARNINGS PER SHARE

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

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

4. ACQUISITIONS

Acquisitions in 2017

ARM, Chipola and Central Gas Asset Acquisitions

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

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

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

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

Acquisition in 2015

Gatherco Merger

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

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

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

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

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

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

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

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

5. SEGMENT INFORMATION

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

Our operations comprise two reportable segments:

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

- *Unregulated Energy.* Includes propane distribution as well as natural gas marketing, gathering, processing, transportation and supply. These operations are unregulated as to their rates and services. Effective June 2016, this segment includes electricity and steam generation through Eight Flags' CHP plant. Through March 2017, this segment also included the operations of Xeron, our propane and crude oil trading subsidiary that began winding down operations at the end of the first quarter of 2017. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

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

The following table presents information about our reportable segments.

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

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

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

Our operations are entirely domestic.

6. SUPPLEMENTAL CASH FLOW DISCLOSURES

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

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

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

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

7. DERIVATIVE INSTRUMENTS

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

Hedging Activities in 2017

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

fair value asset of approximately $1.2 million and a fair value liability of $2,000. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss).

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

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

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

Hedging Activities in 2016

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

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

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

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

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

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedging instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should

converge, which should reduce or eliminate the impact of this ineffectiveness on purchased gas cost. To the extent that our natural gas inventory does not qualify as a hedged item in a fair-value hedge, or has not been designated as such, the natural gas inventory is valued at the lower of cost or net realizable value.

Hedging Activities in 2015

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

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

Commodity Contracts for Trading Activities

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

Balance sheet offsetting

PESCO has entered into master netting agreements with counterparties that enable it net the counterparties' outstanding accounts receivable and payable, which are presented on a net basis in the consolidated balance sheets. The following table summarizes the accounts receivable and payables on a gross and net basis at December 31, 2017 and 2016:

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

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

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency.

Fair values of the derivative contracts recorded in the consolidated balance sheets as of December 31, 2017 and 2016, are as follows:

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

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

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

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

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

(2) As a fair value hedge with no ineffective portion, the unrealized gains and losses associated with this call option are recorded in cost of sales, offset by the corresponding change in the value of propane inventory (hedged item), which is also recorded in cost of sales. The amounts in cost of sales offset to zero, and the unrealized gains and losses of this call option effectively changed the value of propane inventory on the consolidated balance sheets.

Notes to the Consolidated Financial Statements

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability; and

Level 3: Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity).

Financial Assets and Liabilities Measured at Fair Value

The following tables summarize our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy as of December 31, 2017 and 2016, respectively:

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

		Fair Value Measurements Using:		
As of December 31, 2016 *(in thousands)*	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments—equity securities	$ 21	$ 21	$ —	$ —
Investments—guaranteed income fund	561	—	—	561
Investments—mutual funds and other	4,320	4,320	—	—
Total investments	4,902	4,341	—	561
Derivative assets	823	—	823	—
Total assets	$ 5,725	$ 4,341	$ 823	$ 561
Liabilities:				
Derivative liabilities	$ 773	$ —	$ 773	$ —

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

Level 1 Fair Value Measurements:

Investments - equity securities — The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities.

Investments - mutual funds and other — The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.

Level 2 Fair Value Measurements:

Derivative assets and liabilities — The fair values of forward contracts are measured using market transactions in either the listed or OTC markets. The fair value of the propane put/call options, swap agreements and natural gas futures contracts are measured using market transactions for similar assets and liabilities in either the listed or OTC markets.

Level 3 Fair Value Measurements:

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

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

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

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

At December 31, 2017 and 2016, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

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

At December 31, 2017, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of $205.2 million, compared to a fair value of $215.4 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, adjusted for duration, optionality and risk profile. At December 31, 2016, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of $145.9 million compared to the estimated fair value of $161.5 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

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

9. INVESTMENTS

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

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

We classify these investments as trading securities and report them at their fair value. For the years ended December 31, 2017, 2016 and 2015, we recorded net unrealized gains of $1.0 million, $379,000 and $7,000, respectively, in other income (expense) in the consolidated statements of income related to these investments. For the investment in the Rabbi Trust, we also have recorded an associated liability, which is included in other pension and benefit costs in the consolidated balance sheets and is adjusted each period for the gains and losses incurred by the investments in the Rabbi Trust.

10. GOODWILL AND OTHER INTANGIBLE ASSETS

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

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

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

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

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

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

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

11. INCOME TAXES

We file a consolidated federal income tax return. Income tax expense allocated to our subsidiaries is based upon their respective taxable incomes and tax credits. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. Our returns for tax years after 2013 are subject to examination.

We had no net operating loss for federal income tax purposes as of December 31, 2017. As of December 31, 2016, we had a net operating loss for federal income tax purposes of $14.0 million, which we carried back two years. For state income tax purposes, we had net operating losses in various states of $34.2 million and $19.6 million as of December 31, 2017 and 2016, respectively, almost all of which will expire in 2036. We have recorded deferred tax assets of $1.6 million and $893,000 related to state net operating loss carry-forwards at December 31, 2017 and 2016, respectively, but we have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will be fully utilized.

Federal Tax Reform

On December 22, 2017, President Trump signed into law the TCJA. Substantially all of the provisions of the TCJA are effective for taxable years beginning on or after January 1, 2018. The provisions significantly impacting us include the reduction of the corporate federal income tax rate from 35 percent to 21 percent and several technical provisions, including, among others, limiting the utilization of net operating losses arising after December 31, 2017 to 80 percent of taxable income with an indefinite carryforward. Our federal income tax expense for periods beginning on January 1, 2018 will be based on the new federal corporate income tax rate. The specific TCJA provisions related to regulated public utilities generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and continuation of certain rate normalization requirements for accelerated depreciation benefits.

Additionally, enactment of the TCJA resulted in changes to the Internal Revenue Code, which materially impacted our 2017 financial statements. ASC 740, *Income Taxes*, requires recognition of the effects of changes in tax laws in the period in which the law is enacted. ASC 740 requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. We have completed and have made a reasonable estimate of the measurement and accounting of certain effects of the TCJA, which have been reflected in the December 31, 2017 consolidated financial statements, the period in which the TCJA was enacted. At the date of enactment, we re-measured deferred income taxes based upon the new corporate tax rate. For our regulated businesses, the change in deferred income taxes of $98.5 million was recorded as an offset to a regulatory liability, some portion of which may ultimately be subject to refund to customers. We are at various stages of discussion with our regulatory jurisdictions. For our unregulated businesses, the change in deferred income taxes of $14.3 million was recorded as an adjustment to our deferred income taxes and increased our net income.

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

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

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

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

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

(2) Effective tax rate for 2017 includes the impact of the revaluation of deferred tax assets and liabilities for our unregulated businesses due to implementation of the TCJA.

(in thousands)	As of December 31, 2017	2016
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	$ 133,581	$ 218,074
Acquisition adjustment	9,323	14,840
Loss on reacquired debt	153	442
Deferred gas costs	2,574	1,846
Other	5,422	6,375
Total deferred income tax liabilities	151,053	241,577
Deferred income tax assets:		
Pension and other employee benefits	4,698	6,230
Environmental costs	1,744	2,592
Net operating loss carryforwards	1,625	952
Investment tax credit carryforwards	—	2,643
Self insurance	164	189
Storm reserve liability	717	1,131
Other	6,255	4,946
Total deferred income tax assets	15,203	18,683
Deferred Income Taxes Per Consolidated Balance Sheets	$ 135,850	$ 222,894

12. LONG-TERM DEBT

Our outstanding long-term debt is shown below:

(in thousands)	As of December 31, 2017	2016
FPU secured first mortgage bonds:		
9.08% bond, due June 1, 2022	$ 7,982	$ 7,978
Uncollateralized Senior Notes:		
6.64% note, due October 31, 2017	—	2,727
5.50% note, due October 12, 2020	6,000	8,000
5.93% note, due October 31, 2023	18,000	21,000
5.68% note, due June 30, 2026	26,100	29,000
6.43% note, due May 2, 2028	7,000	7,000
3.73% note, due December 16, 2028	20,000	20,000
3.88% note, due May 15, 2029	50,000	50,000
3.25% note, due April 30, 2032	70,000	—
Promissory notes	97	168
Capital lease obligation	2,070	3,471
Less: debt issuance costs	(433)	(291)
Total long-term debt	206,816	149,053
Less: current maturities	(9,421)	(12,099)
Total long-term debt, net of current maturities	$ 197,395	$ 136,954

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

Shelf Agreements

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

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

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

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

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

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

Secured First Mortgage Bonds

We guaranteed FPU's first mortgage bonds, which are secured by a lien covering all of FPU's property. FPU's first mortgage bonds contain a restriction that limits the payment of dividends by FPU. It provides that FPU cannot make dividends or other restricted payments in excess of the sum of $2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2017, FPU's cumulative net income base was $142.6 million, offset by restricted payments of $37.6 million, leaving $104.9 million of cumulative net income for FPU free of restrictions pursuant to this covenant.

The dividend restrictions in FPU's first mortgage bonds resulted in approximately $43.0 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2017. This represents approximately 9 percent of our consolidated net assets. Other than the dividend restrictions in FPU's first mortgage bonds, there are no legal, contractual or regulatory restrictions on the net assets of our subsidiaries.

Uncollateralized Senior Notes

All of our uncollateralized Senior Notes require periodic principal and interest payments as specified in each note. They also contain various restrictions. The most stringent restrictions state that we must maintain equity of at least 40 percent of total capitalization, and the fixed charge coverage ratio must be at least 1.2 times. The most recent Senior Notes issued in December 2013 also contain a restriction that we must maintain an aggregate net book value in our regulated business assets of at least 50 percent of our consolidated total assets. Failure to comply with those covenants could result in accelerated due dates and/or termination of the Senior Note agreements.

Certain uncollateralized Senior Notes contain a "restricted payments" covenant as defined in the respective note agreements. The most restrictive covenants of this type are included within the 5.93 percent Senior Note, due October 31, 2023. The covenant provides that we cannot pay or declare any dividends or make any other restricted payments in excess of the sum of $10.0 million, plus our consolidated net income accrued on and after January 1, 2003. As of December 31, 2017, the cumulative consolidated net income base was $387.7 million, offset by restricted payments of $178.0 million), leaving $209.7 million of cumulative net income free of restrictions.

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

13. SHORT-TERM BORROWINGS

At December 31, 2017 and 2016, we had $251.0 million and $209.9 million, respectively, of short-term borrowings outstanding at the weighted average interest rates of 2.42 percent and 1.43 percent, respectively. In October 2015, we entered into a Credit Agreement with the Lenders for a $150.0 million Revolver through October 2020 subject to the terms and conditions as specified. In November 2017, we entered into a new $40.0 million short-term credit facility with a new lender. As a result, we now have an aggregate of $370.0 million in credit lines comprised of five unsecured bank credit facilities with four financial institutions, with $220.0 million in total available credit, and a Revolver with five participating Lenders totaling $150.0 million. We incurred commitment fees of $131,000, $145,000 and $106,000 in 2017, 2016 and 2015, respectively. The following table summarizes our short-term borrowing facilities information at December 31, 2017 and 2016.

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

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

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

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

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

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

These bank credit facilities are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures. We are authorized by our Board of Directors to borrow up to $275.0 million of short-term debt, as required, from these short-term lines of credit. As of February 27, 2018 the Board increased this limit from $275.0 million to $350.0 million.

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

14. Lease Obligations

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

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

15. STOCKHOLDERS' EQUITY

Preferred Stock

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

Common Stock Public Offering

In September 2016, we completed a public offering of 960,488 shares of our common stock at a public offering price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 million, which were added to our general funds and used primarily to repay a portion of our short-term debt under unsecured lines of credit.

Shareholders' Rights

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

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

Accumulated Other Comprehensive (Loss)

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options and natural gas futures and swap contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss).

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

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contract Cash Flow Hedges	Total
As of December 31, 2016	$ (5,360)	$ 482	$ (4,878)
Other comprehensive income before reclassifications	281	159	440
Amounts reclassified from accumulated other comprehensive income/(loss)	336	(170)	166
Net current-period other comprehensive income/(loss)	617	(11)	606
As of December 31, 2017	**$ (4,743)**	**$ 471**	**$ (4,272)**

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

The following table presents amounts reclassified out of accumulated other comprehensive income (loss) for the years ended December 31, 2017, 2016 and 2015. Deferred gains and losses of our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	For the Year Ended December 31,		
(in thousands)	2017	2016	2015
Amortization of defined benefit pension and postretirement plan items:			
Prior service cost [1]	$ 77	$ 77	$ 68
Net gain [1]	(636)	(871)	(650)
Total before income taxes	(559)	(794)	(582)
Income tax benefit	223	320	233
Net of tax	$ (336)	$ (474)	$ (349)
Gains and losses on commodity contracts cash flow hedges			
Propane swap agreements [2]	$ 1,607	$ (322)	$ (120)
Natural gas swaps [2]	(822)	—	(55)
Natural gas futures [2]	(456)	345	(31)
Total before income taxes	329	23	(206)
Income tax impact	(159)	(3)	83
Net of tax	$ 170	$ 20	$ (123)
Total reclassifications for the period	$ (166)	$ (454)	$ (472)

(1) These amounts are included in the computation of net periodic benefits. See Note 16, *Employee Benefit Plans*, for additional details.

(2) These amounts are included in the effects of gains and losses from derivative instruments. See Note 7, *Derivative Instruments*, for additional details.

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

16. Employee Benefit Plans

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

Defined Benefit Pension Plans

We sponsor three defined benefit pension plans: the Chesapeake Pension Plan, the FPU Pension Plan and the Chesapeake SERP.

The Chesapeake Pension Plan was closed to new participants, effective January 1, 1999, and was frozen with respect to additional years of service and additional compensation, effective January 1, 2005. Benefits under the Chesapeake Pension Plan were based on each participant's years of service and highest average compensation, prior to the freezing of the plan. Active participants on the date the Chesapeake Pension Plan was frozen were credited with two additional years of service. The unfunded liability for the Chesapeake Pension Plan of approximately $2.1 million and $2.7 million at December 31, 2017 and 2016, is included in the other pension and benefit costs liability in our consolidated balance sheets.

The FPU Pension Plan covers eligible FPU non-union employees hired before January 1, 2005 and union employees hired before the respective union contract expiration dates in 2005 and 2006. Prior to the FPU merger, the FPU Pension Plan was frozen with respect to additional years of service and additional compensation, effective December 31, 2009. The unfunded liability for the FPU Pension Plan of approximately $16.3 million and $20.6 million at December 31, 2017 and 2016, respectively, is included in the other pension and benefit costs liability in our consolidated balance sheets.

The Chesapeake SERP was frozen with respect to additional years of service and additional compensation as of December 31, 2004. Benefits under the Chesapeake SERP were based on each participant's years of service and highest average compensation, prior to the freezing of the plan. Active participants on the date the Chesapeake SERP was frozen were credited with two additional years of service. The unfunded liability for the Chesapeake SERP of approximately $2.4 million, at both December 31, 2017 and 2016, is included in the other pension and benefit costs liability in our consolidated balance sheets.

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

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

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

Included in the net periodic costs for the FPU Pension Plan is continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated operations for the changes in funded status that occurred, but were not recognized as part of net periodic cost, prior to the merger with Chesapeake Utilities in October 2009. This was previously deferred as a regulatory asset to be recovered through rates pursuant to an order by the Florida PSC. The unamortized balance of this regulatory asset was $1.3 million and $2.1 million at December 31, 2017 and 2016, respectively.

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

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

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

Our funding policy provides that payments to the trustee of each qualified plan shall be equal to at least the minimum funding requirements of the Employee Retirement Income Security Act of 1974. The following schedule summarizes the assets of the Chesapeake Pension Plan and the FPU Pension Plan, by investment type, at December 31, 2017, 2016 and 2015:

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

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

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

Asset Allocation Strategy

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

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

At December 31, 2017 and 2016, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

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

(1) Includes funds that invest primarily in United States common stocks.
(2) Includes funds that invest primarily in foreign equities and emerging markets equities.
(3) Includes funds that actively invest in both equity and debt securities, funds that sell short securities and funds that provide long-term capital appreciation. The funds may invest in debt securities below investment grade.
(4) Includes funds that invest in investment grade and fixed income securities.
(5) Includes funds that invest primarily in commodity-linked derivative instruments and fixed income securities.
(6) Includes funds that invest primarily in real estate.
(7) Includes investment in a group annuity product issued by an insurance company.
(8) Certain investments that were measured at net asset value per share have not been classified in the fair value hierarchy. These amounts are presented to reconcile to total pension plan assets.

At December 31, 2017 and 2016, all of the investments were classified under the same fair value measurement hierarchy (Level 1 through Level 3) described under Note 8, *Fair Value of Financial Instruments*. The Level 3 investments were recorded at fair value based on the contract value of annuity products underlying guaranteed deposit accounts, which was calculated using discounted cash flow models. The contract value of these products represented deposits made to the contract, plus earnings at guaranteed crediting rates, less withdrawals and fees.

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

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

Other Postretirement Benefits Plans

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

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

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

Net periodic postretirement benefit costs for 2017, 2016, and 2015 include the following components:

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

Similar to the FPU Pension Plan, continued amortization of the FPU Medical Plan regulatory asset related to the unrecognized cost prior to the merger with Chesapeake Utilities was included in the net periodic cost. The unamortized balance of this regulatory asset was $22,000 and $30,000 at December 31, 2017 and 2016, respectively.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive loss or as a regulatory asset as of December 31, 2017:

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

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

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

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

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

Assumptions

The assumptions used for the discount rate to calculate the benefit obligations of all the plans were based on the interest rates of high-quality bonds in 2017, reflecting the expected lives of the plans. In determining the average expected return on plan assets for each applicable plan, various factors, such as historical long-term return experience, investment policy and current and expected allocation, were considered. Since Chesapeake Utilities' plans and FPU's plans have different expected plan lives, particularly in light of the lump-sum-payment option provided in the Chesapeake Pension Plan, different assumptions regarding discount rate and expected return on plan assets were selected for Chesapeake Utilities' and FPU's plans. Since both pension plans are frozen with respect to additional years of service and compensation, the rate of assumed compensation increases is not applicable.

The health care inflation rate for 2017 used to calculate the benefit obligation is 5.0 percent for medical and 6.0 percent for prescription drugs for the Chesapeake Postretirement Plan; and 5.0 percent for both medical and prescription drugs for the FPU Medical Plan. A one-percentage point increase in the health care inflation rate from the assumed rate would increase the accumulated postretirement benefit obligation by approximately $277,000 as of December 31, 2017, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2017 by approximately $11,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $215,000 as of December 31, 2017, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2017 by approximately $8,000.

Estimated Future Benefit Payments

In 2018, we expect to contribute $359,000 and $1.5 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $151,000 to the Chesapeake SERP. We also expect to contribute $97,000 and $88,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2017. The schedule below shows the estimated future benefit payments for each of the plans previously described:

(in thousands)	Chesapeake Pension Plan[1]	FPU Pension Plan[1]	Chesapeake SERP[2]	Chesapeake Postretirement Plan[2]	FPU Medical Plan[2]
2018	$ 687	$ 3,078	$ 151	$ 97	$ 88
2019	$ 490	$ 3,207	$ 150	$ 96	$ 94
2020	$ 675	$ 3,304	$ 149	$ 85	$ 87
2021	$ 779	$ 3,362	$ 385	$ 82	$ 91
2022	$ 592	$ 3,536	$ 146	$ 81	$ 93
Years 2023 through 2027	$ 5,278	$ 18,608	$ 738	$ 290	$ 404

(1) The pension plan is funded; therefore, benefit payments are expected to be paid out of the plan assets.

(2) Benefit payments are expected to be paid out of our general funds.

Retirement Savings Plan

For the years ended December 31, 2017, 2016 and 2015, we sponsored a 401(k) Retirement Savings Plan. This plan is offered to all eligible employees who have completed three months of service. We match 100 percent of eligible participants' pre-tax contributions to the Retirement Savings Plan up to a maximum of six percent of eligible compensation. The employer matching contribution is made in cash and is invested based on a participant's investment directions. In addition, we may make a discretionary supplemental contribution to participants in the plan, without regard to whether or not they make pre-tax contributions. Any

supplemental employer contribution is generally made in our common stock. With respect to the employer match and supplemental employer contribution, employees are 100 percent vested after two years of service or upon reaching 55 years of age while still employed by us. New employees who do not make an election to contribute and do not opt out of the Retirement Savings Plan will be automatically enrolled at a deferral rate of three percent, and the automatic deferral rate will increase by one percent per year up to a maximum of six percent. In 2018, the maximum automatic deferral rate will be increased to ten percent. All contributions and matched funds can be invested among the mutual funds available for investment.

Employer contributions to our Retirement Savings Plan totaled $5.0 million, $4.5 million, and $4.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017, there were 831,183 shares of our common stock reserved to fund future contributions to the Retirement Savings Plan.

Non-Qualified Deferred Compensation Plan

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

All obligations arising under the Non-Qualified Deferred Compensation Plan are payable from our general assets, although we have established a Rabbi Trust to informally fund the plan. Deferrals of cash compensation may be invested by the participants in various mutual funds (the same options that are available in the Retirement Savings Plan). The participants are credited with gains or losses on those investments. Deferred stock compensation may not be diversified. The participants are credited with dividends on our common stock in the same amount that is received by all other stockholders. Such dividends are reinvested into our common stock. Assets held in the Rabbi Trust had a fair value of $6.7 million and $4.9 million at December 31, 2017 and 2016, respectively. (See *Note 9, Investments*, for further details). The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Deferrals of executive base compensation and cash bonuses and directors' cash retainers are paid in cash. All deferrals of executive performance shares, which represent deferred stock units, and directors' stock retainers are paid in shares of our common stock, except that cash is paid in lieu of fractional shares. The value of our stock held in the Rabbi Trust is classified within the stockholders' equity section of the consolidated balance sheets and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Non-Qualified Deferred Compensation Plan totaled $3.4 million and $2.4 million at December 31, 2017 and 2016, respectively.

17. SHARE-BASED COMPENSATION PLANS

Our non-employee directors and key employees have been granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period. We have 509,202 shares of common stock reserved for issuance under the SICP.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the SICP for the years ended December 31, 2017, 2016 and 2015:

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

Stock Options

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

Non-employee Directors

Shares granted to non-employee directors are issued in advance of these directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2017, each of our non-employee directors received an annual retainer of 835 shares of common stock under the SICP for board service through the 2018 Annual Meeting of Stockholders. A summary of stock activity for our non-employee directors for the years ended December 31, 2017 and 2016 is presented below:

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

The weighted average grant date fair value of shares granted to our non-employee directors during 2017, 2016 and 2015 was $71.80, $62.90 and $45.54 per share, respectively. The intrinsic values of the shares granted to our non-employee directors are equal to the fair value of these awards on the date of grant. At December 31, 2017, there was $179,000 of unrecognized compensation expense related to these awards. This expense will be fully recognized by April 2018, which approximates the expected remaining service period of those directors.

Key Employees

Our Compensation Committee is authorized to grant our key employees the right to receive awards of shares of our common stock, contingent upon the achievement of established performance goals. These awards are subject to certain post-vesting transfer restrictions.

We currently have outstanding several multi-year performance plans, which are based upon the successful achievement of long-term goals, growth and financial results which comprise both market-based and performance-based conditions or targets. The fair value of each share of stock, tied to a performance-based condition or target, is equal to the market price of our common stock on

the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each share of market-based award granted.

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

	Number of Shares	Weighted Average Fair Value
Outstanding — December 31, 2015	110,398	$ 38.34
Granted	46,571	$ 67.90
Vested	(39,553)	$ 31.79
Expired	(2,325)	$ 42.25
Outstanding — December 31, 2016	115,091	$ 51.85
Granted	52,355	$ 63.42
Vested	(32,926)	$ 38.88
Expired	(1,878)	$ 39.97
Outstanding — December 31, 2017	**132,642**	**$ 53.00**

In 2017, 2016 and 2015, we withheld shares with a value at least equivalent to the employees' minimum statutory obligation for the applicable income and other employment taxes, and remitted the cash to the appropriate taxing authorities with the executives electing to receive the net shares. The total number of shares withheld of 10,269, 12,031 and 12,620 for 2017, 2016 and 2015, respectively, were based on the closing price of the shares on their award date. Total payments for the employees' tax obligations to the taxing authorities were approximately $692,000, $770,000 and $592,000, in 2017, 2016 and 2015, respectively. The tax benefits associated with these obligations for 2017, 2016 and 2015 are $349,000, $285,000, and $297,000, respectively. The tax benefit for 2015 was recorded in additional paid-in capital in the consolidated statements of stockholders' equity. The tax benefit for 2017 and 2016 was included in the statements of income due to the adoption of new accounting guidance.

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

18. RATES AND OTHER REGULATORY ACTIVITIES

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC. Chesapeake Utilities' Florida Division and FPU's natural gas and electric distribution operations continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

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

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

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

Maryland Division and Sandpiper

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

Florida

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

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

Electric Limited Proceeding: In July 2017, FPU's electric division filed a petition with the Florida PSC, requesting approval to include $15.2 million of certain capital project expenditures in its rate base and to adjust its base rates accordingly. These expenditures are designed to improve the stability and safety of the electric system while enhancing the capability of FPU's grid. Included in the $15.2 million is the interconnection project with FPL, which enables FPU to mitigate fuel costs for its electric customers. In December 2017, the Florida PSC approved this petition with an effective date of January 1, 2018. The settlement agreement prescribes the methodology for adjusting the new rates based on the lower federal income tax rate and the process and methodology regarding the refund of deferred income taxes, reclassified as a regulatory liability, as a result of the TCJA.

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

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

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

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

Eastern Shore

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

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

2017 Expansion Project: In May 2016, FERC approved Eastern Shore's request to initiate the pre-filing review process for its 2017 Expansion Project. The 2017 Expansion Project's facilities include approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional compressor unit at Eastern Shore's existing Daleville compressor station in Chester County, Pennsylvania; and approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. Eastern Shore entered into precedent agreements with seven existing customers, including three affiliates of Chesapeake Utilities, for a total of 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system with an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities.

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

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

On August 1, 2017, Eastern Shore implemented new rates, subject to refund based upon the outcome of the rate proceeding. Eastern Shore recorded incremental revenue of approximately $3.7 million for the year ended December 31, 2017, and established a regulatory liability to reserve a portion of the total incremental revenues generated by the new rates until the rate case settlement is approved by the FERC and customers receive refunds according to the terms of the settlement agreement. Eastern Shore filed an uncontested settlement agreement and a motion to place interim settlement rates into effect on January 1, 2018. In December 2017, FERC issued an order approving the implementation of interim settlement rates. Not considering the effects of the TCJA, base rates will increase, on an annual basis, by approximately $9.8 million. On February 28, 2018, FERC approved the settlement agreement by a letter order. The order will be deemed final upon the expiration of the right to rehearing on March 30, 2018. Eastern Shore will recover the costs of its 2016 System Reliability Project (placed into service in 2017), along the cost of investments and expenses associated with various expansion, reliability and safety initiatives.

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

At December 31, 2017 and 2016, our regulated utility operations had recorded the following regulatory assets and liabilities included in our consolidated balance sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers' rates.

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

(1) We are allowed to recover the asset or are required to pay the liability in rates. We do not earn an overall rate of return on these assets.

(2) The Florida PSC allowed us to recover through a surcharge, capital and other program-related-costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services (defined as any material other than coated steel or plastic) in FPU's natural gas distribution, Fort Meade and Chesapeake Utilities' Florida Division. We are allowed to recover the asset or are required to pay the liability in rates related to GRIP.

(3) The Florida PSC allowed FPU to treat as a regulatory asset the portion of the unrecognized costs pursuant to ASC Topic 715, *Compensation - Retirement Benefits*, related to its regulated operations. See Note 16, *Employee Benefit Plans*, for additional information.

(4) All of our environmental expenditures incurred to date and our current estimate of future environmental expenditures have been approved by various PSCs for recovery. See Note 19, *Environmental Commitments and Contingencies*, for additional information on our environmental contingencies.

(5) We are allowed to include the premiums paid in various natural gas utility acquisitions in Florida in our rate bases and recover them over a specific time period pursuant to the Florida PSC approvals. Included in these amounts are $1.3 million of the premium paid by FPU, $34.2 million of the premium paid by us in 2009, including the gross up of the amount for income tax, because it is not tax deductible, and $746,000 of the premium paid by FPU in 2010.

(6) Gains and losses resulting from the reacquisition of long-term debt are amortized over future periods as adjustments to interest expense in accordance with established regulatory practice.

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

(8) See Note 1, *Summary of Significant Accounting Policies*, for additional information on our asset removal cost policies.

(9) We recorded a regulatory liability for our regulated businesses related to the revaluation of accumulated deferred tax assets/liabilities as a result of the TCJA. Based upon the regulatory proceedings, we will pass back the respective portion of the excess accumulated deferred taxes to rate payers. See Note 11, *Income Taxes*, for additional information.

19. Environmental Commitments and Contingencies

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

MGP Sites

We have participated in the investigation, assessment or remediation of, and have exposures at, seven former MGP sites. Those sites are located in Salisbury, Maryland, Seaford, Delaware and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the MDE regarding another former MGP site located in Cambridge, Maryland.

As of December 31, 2017, we had approximately $9.6 million in environmental liabilities, related to FPU's MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to its MGP sites. Approximately $11.0 million has been recovered as of December 31, 2017, leaving approximately $3.0 million in regulatory assets for future recovery of environmental costs from FPU's customers.

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

Jurisdiction	MGP Site	Status	Cost to Clean up	Recovery through Rates
Florida	West Palm Beach	Remedial actions approved by FDEP have been implemented on the east parcel of the site. Similar remedial actions expected to be implemented on other remaining portions.	Between $4.5 million to $15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.	Yes
Florida	Sanford	In January 2007, FPU and the Sanford group signed a Third Participation Agreement. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000, which has been paid to an escrow account. The EPA issued a preliminary close-out report in December 2014. Groundwater monitoring and statutory five-year reviews to ensure performance of the approved remedy will continue on this site.	FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be approximately $24,000.	Yes
Florida	Winter Haven	Remediation is ongoing.	Not expected to exceed $425,000, which includes costs of implementing institutional controls at the site.	Yes
Delaware	Seaford	Proposed plan for implementation approved by DNREC in July 2017.	$273,000 to $465,000.	Yes
Maryland	Cambridge	Currently in discussions with MDE.	Unable to estimate.	N/A

20. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

We have entered into contractual commitments to purchase natural gas, electricity and propane from various suppliers. The contracts have various expiration dates. In 2017, our Delmarva Peninsula natural gas distribution operations entered into asset management agreements with PESCO to manage a portion of their natural gas transportation and storage capacity. The agreements were effective as of April 1, 2017, and each has a three-year term, expiring on March 31, 2020. Previously, the Delaware PSC approved PESCO to serve as an asset manager with respect to our Delaware Division.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with EGWIC to purchase propane over a six - year term ending in May 2019. Sandpiper's current annual commitment is estimated at approximately 2.7 million gallons. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices.

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC over a six-year term ending in May 2019. Sharp's current annual commitment is estimated at approximately 2.7 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC, and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified in the other agreement.

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

FPU's electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with FPL requires FPU to meet or exceed a debt service coverage ratio of 1.25 times based on the results of the prior 12 months. If this ratio is not met by FPU, it must provide an irrevocable letter of credit or pay all amounts outstanding under the agreement within five business days. FPU's electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken, or proposed to be taken, to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could also result in FPU having to provide an irrevocable letter of credit. As of December 31, 2017, FPU was in compliance with all of the requirements of its fuel supply contracts.

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

The total purchase obligations for natural gas, electric and propane supplies are approximately $152.9 million for 2018, $122.8 million for 2019-2020, $44.6 million for 2021-2022 and $149.6 million thereafter.

Corporate Guarantees

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

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily PESCO. These corporate guarantees provide for the payment of natural gas purchases in the event that PESCO defaults. PESCO has never defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at December 31, 2017 was $72.0 million, with the guarantees expiring on various dates through December 2018.

Chesapeake Utilities also guarantees the payment of FPU's first mortgage bonds. The maximum exposure under this guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU's first mortgage bonds approximate their carrying values (see Note 12, *Long-Term Debt,* for further details).

As of December 31, 2017, we have issued letters of credit totaling approximately $5.0 million related to the electric transmission services for FPU's electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland

divisions, the payment of natural gas purchases for PESCO, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through December 2018. There have been no draws on these letters of credit as of December 31, 2017. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

21. QUARTERLY FINANCIAL DATA (UNAUDITED)

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

	For the Quarters Ended			
	March 31	June 30	September 30	December 31
(in thousands except per share amounts)				
2017 [1]				
Operating Revenues	$ 185,160	$ 125,084	$ 126,936	$ 180,403
Operating Income	$ 34,676	$ 13,666	$ 14,239	$ 23,263
Net Income	$ 19,144	$ 6,046	$ 6,833	$ 26,101
Earnings per share:				
Basic	$ 1.17	$ 0.37	$ 0.42	$ 1.60
Diluted	$ 1.17	$ 0.37	$ 0.42	$ 1.59
2016 [1]				
Operating Revenues	$ 146,296	$ 102,342	$ 108,348	$ 141,874
Operating Income	$ 36,380	$ 15,742	$ 10,156	$ 21,819
Net Income	$ 20,367	$ 8,029	$ 4,416	$ 11,863
Earnings per share:				
Basic	$ 1.33	$ 0.52	$ 0.29	$ 0.73
Diluted	$ 1.33	$ 0.52	$ 0.29	$ 0.73

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer, with the participation of other Company officials, have evaluated our "disclosure controls and procedures" (as such term is defined under Rule 13a-15(e) and 15d–15(e) promulgated under the Securities Exchange Act of 1934, as amended) as of December 31, 2017. Based upon their evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2017.

CHANGE IN INTERNAL CONTROLS

There has been no change in internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2017, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

CEO AND CFO CERTIFICATIONS

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2017. In addition, on June 1, 2017, our Chief Executive Officer certified to the NYSE that he was not aware of any violation by us of the NYSE corporate governance listing standards.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, our management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria established in an updated report entitled "Internal Control — Integrated Framework," issued in May 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management has evaluated and concluded that our internal control over financial reporting was effective as of December 31, 2017.

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

ITEM 9B. OTHER INFORMATION.

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

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

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

PART III

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

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

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

ITEM 11. EXECUTIVE COMPENSATION.

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

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

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

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

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

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

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this report:

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

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

(a)(3) The Exhibits below.

• Exhibit 1.1	Underwriting Agreement entered into by Chesapeake Utilities Corporation and Wells Fargo Securities, LLC, RBC Capital Markets, LLC, Janney Montgomery Scott LLC., Robert W. Baird & Co., Incorporated, J.J.B. Hilliard, W.L. Lyons, LLC, Ladenburg Thalmann & Co. Inc., U.S. Capital Advisors LLC and BB&T Securities, LLC on September 22, 2016, relating to the sale and issuance of 835,207 shares of the Company's common stock, is incorporated herein by reference to Exhibit 1.1 of the Company's current report on Form 8-K, filed on September 28, 2016, File No. 001-11590.
• Exhibit 3.1	Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q for the period ended June 30, 2010, File No. 001-11590.
• Exhibit 3.2	Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 4, 2012, are incorporated herein by reference to Exhibit 3 of our Current Report on Form 8-K, filed December 7, 2012, File No. 001-11590.
• Exhibit 3.3	First Amendment to the Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 3, 2014, is incorporated herein by reference to Exhibit 3.3 of our Annual Report on Form 10-K for the year ended December 31, 2014.
• Exhibit 3.4	Second Amendment to the Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective November 2, 2016, is incorporated herein by reference to Exhibit 3.3 of our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016, File No. 001-11590.
• Exhibit 3.5	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed May 9, 2017, File No. 001-11590.
• Exhibit 3.6	Certificate of Elimination of Series A Participating Cumulative Preferred Stock of Chesapeake Utilities Corporation is filed herewith.
• Exhibit 4.1	Note Agreement dated October 31, 2002, between Chesapeake Utilities Corporation, as issuer, and Massachusetts Mutual Life Insurance Company, C.M. Life Insurance Company, American United Life Insurance Company, Pioneer Mutual Life Insurance Company and The State Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 6.64% Senior Notes due 2017, is incorporated herein by reference to Exhibit 2 of our Current Report on Form 8-K, filed November 6, 2002, File No. 001-11590.
• Exhibit 4.2	Note Agreement dated October 18, 2005, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management, Inc., relating to the private placement of Chesapeake Utilities Corporation's 5.5% Senior Notes due 2020, is incorporated herein by reference to Exhibit 4.1 of our Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-11590.
• Exhibit 4.3	Note Agreement dated October 31, 2008, among Chesapeake Utilities Corporation, as issuer, General American Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 5.93% Senior Notes due 2023.†

• Exhibit 4.4	Note Agreement dated June 29, 2010, among Chesapeake Utilities Corporation, as issuer, Metropolitan Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 5.68% Senior Notes due 2026 and Chesapeake Utilities Corporation's 6.43% Senior Notes due 2028.†
• Exhibit 4.5	Note Agreement dated September 5, 2013, among Chesapeake Utilities Corporation, as issuer, and certain note holders, relating to the private placement of Chesapeake Utilities Corporation's 3.73% Senior Notes due 2028 and Chesapeake Utilities Corporation's 3.88% Senior Notes due 2029.†
• Exhibit 4.6	Form of Indenture of Mortgage and Deed of Trust dated September 1, 1942, between Florida Public Utilities Company and the trustee, for the First Mortgage Bonds, is incorporated herein by reference to Exhibit 7-A of Florida Public Utilities Company's Registration No. 2-6087.
• Exhibit 4.7	Seventeenth Supplemental Indenture dated April 12, 2011, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guarantees the payment and performance obligations of Florida Public Utilities Company under the Indenture, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the period ended March 31, 2011, File No. 001-11590.
• Exhibit 4.8	Sixteenth Supplemental Indenture dated December 1, 2009, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guaranteed the secured First Mortgage Bonds of Florida Public Utilities Company under the Merger Agreement, is incorporated herein by reference to Exhibit 4.9 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
• Exhibit 4.9	Thirteenth Supplemental Indenture dated June 1, 1992, pursuant to which Florida Public Utilities, on May 1, 1992, privately placed $8,000,000 of its 9.08% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 1992.
• Exhibit 4.10	Private Shelf Agreement dated October 8, 2015, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management Inc., relating to the purchase of Chesapeake Utilities Corporation unsecured Senior Notes, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2015, File No. 001-11590.
• Exhibit 4.11	Rights Agreement, dated August 20, 1999, by and between Registrant and BankBoston, N.A., as rights agent, is incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed on August 24, 1999, File No. 001-11590.
• Exhibit 4.12	First Amendment to Rights Agreement, dated September 12, 2008, by and between Registrant and Computershare Trust Company, N.A., as successor rights agent, is incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed on September 12, 2008, File No. 001-11590.
• Exhibit 4.13	Second Amendment to Rights Agreement by and between Chesapeake Utilities Corporation and Computershare Trust Company, N.A., dated as of February 27, 2018 is filed herewith.
• Exhibit 10.1*	Chesapeake Utilities Corporation Cash Bonus Incentive Plan, effective January 1, 2015, is incorporated herein by reference to our Proxy Statement dated March 31, 2015, in connection with our Annual Meeting held on May 6, 2015, File No. 001-11590.
• Exhibit 10.2*	Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan, effective May 2, 2013 is incorporated herein by reference to our Proxy Statement dated March 29, 2013 in connection with our Annual Meeting held on May 2, 2013, File No. 001-11590.
• Exhibit 10.3*	Non-Qualified Deferred Compensation Plan, effective January 1, 2014, is incorporated herein by reference to Exhibit 10.8 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
• Exhibit 10.4*	Executive Employment Agreement dated January 14, 2011, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
• Exhibit 10.5*	Amendment to Executive Employment Agreement effective January 1, 2014, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K filed January 14, 2014, File No. 001-11590.

- Exhibit 10.6* Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.9 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
- Exhibit 10.7* Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.10 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
- Exhibit 10.8* Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Elaine B. Bittner, incorporated herein by reference to Exhibit 10.11 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
- Exhibit 10.9* Executive Employment Agreement dated January 1, 2015, between Chesapeake Utilities Corporation and Jeffry M. Householder, is incorporated herein by reference to Exhibit 10.15 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
- Exhibit 10.10* Form of Performance Share Agreement, effective January 7, 2014 for the period 2014 to 2016, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, and Jeffry M. Householder is incorporated herein by reference to Exhibit 10.18 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
- Exhibit 10.11* Form of Performance Share Agreement, effective January 13, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner and Jeffry M. Householder, is incorporated herein by reference to Exhibit 10.19 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
- Exhibit 10.12* Form of Performance Share Agreement, dated March 6, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and James F. Moriarty is incorporated herein by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the period ended September 30, 2015, File No. 001-11590.
- Exhibit 10.13* Form of Performance Share Agreement, dated January 12, 2016 for the period 2016 to 2018, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder and James F. Moriarty, is incorporated herein by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the period ended December 31, 2015, File No. 001-11590.
- Exhibit 10.14* Chesapeake Utilities Corporation Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.27 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
- Exhibit 10.15* First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Plan as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.30 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
- Exhibit 10.16 Revolving Credit Agreement dated December 29, 2014, between Chesapeake Utilities Corporation and Citizens Bank, National Association, as lender, is incorporated herein by reference to Exhibit 10.25 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
- Exhibit 10.17 Revolving Credit Agreement dated October 8, 2015, between Chesapeake Utilities Corporation and PNC Bank, National Association, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada and Wells Fargo Bank, National Association as lenders, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2015, File No. 001-11590.
- Exhibit 10.18 First Amendment dated February 25, 2016 to the Revolving Credit Agreement dated October 8, 2015, between Chesapeake Utilities Corporation and PNC Bank, National Association, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada and Wells Fargo Bank, National Association as lenders, is incorporated herein by reference to Exhibit 10.24 of our Annual Report on Form 10-K for the year ended December 31, 2015, File No. 001-11590.

- Exhibit 10.19 — Promissory Note, contained as an exhibit to the Revolving Credit Agreement dated December 29, 2014, between Chesapeake Utilities Corporation and Citizens Bank, National Association, as lender, is incorporated herein by reference to Exhibit 10.26 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
- Exhibit 10.20* — Executive Employment Agreement dated May 10, 2016, between Chesapeake Utilities Corporation and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the year ended June 30, 2016, File No. 001-11590.
- Exhibit 10.21* — Form of Performance Share Agreement, effective February 23, 2017 for the period 2017 to 2019, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder, and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the year ended June 30, 2017, File No. 001-11590.
- Exhibit 12 — Computation of Ratio of Earning to Fixed Charges is filed herewith.
- Exhibit 21 — Subsidiaries of the Registrant is filed herewith.
- Exhibit 23.1 — Consent of Independent Registered Public Accounting Firm is filed herewith.
- Exhibit 31.1 — Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), is filed herewith.
- Exhibit 31.2 — Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), is filed herewith.
- Exhibit 32.1 — Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, is filed herewith.
- Exhibit 32.2 — Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, is filed herewith.
- Exhibit 101.INS XBRL Instance Document is filed herewith.
- Exhibit 101.SCH XBRL Taxonomy Extension Schema Document is filed herewith.
- Exhibit 101.CAL XBRL Taxonomy Extension Calculation Linkbase Document is filed herewith.
- Exhibit 101.DEF XBRL Taxonomy Extension Definition Linkbase Document is filed herewith.
- Exhibit 101.LAB XBRL Taxonomy Extension Label Linkbase Document is filed herewith.
- Exhibit 101.PRE XBRL Taxonomy Extension Presentation Linkbase Document is filed herewith.

* Management contract or compensatory plan or agreement.

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

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

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

CHESAPEAKE UTILITIES CORPORATION

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

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

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

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

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

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

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

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

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

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

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

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

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

Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions: Charged to Income	Additions: Other Accounts [1]	Deductions [2]	Balance at End of Year
(In thousands)					
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
2017	**$ 909**	**$ 602**	**$ 337**	**$ (912)**	**$ 936**
2016	$ 909	$ 985	$ 340	$ (1,325)	$ 909
2015	$ 1,120	$ 979	$ 246	$ (1,436)	$ 909

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

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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended: December 31, 2018

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

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

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

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

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

RECEIVED-DOCKETING DIV
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PUCO

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

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

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

DOCUMENTS INCORPORATED BY REFERENCE

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

CHESAPEAKE UTILITIES CORPORATION

FORM 10-K

YEAR ENDED DECEMBER 31, 2018

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GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

CDD: Cooling Degree-Day

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

CHP: Combined Heat and Power Plant

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

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

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

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

Dts/d: Dekatherms per day

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

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

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

FGT: Florida Gas Transmission Company

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

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

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

GAAP: Generally Accepted Accounting Principles

GRIP: Gas Reliability Infrastructure Program

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

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

HDD: Heating Degree Day

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

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

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

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

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

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

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

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

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

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

Revolver: Our unsecured revolving credit facility with certain lenders

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

SEC: Securities and Exchange Commission

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

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

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

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

SICP: 2013 Stock and Incentive Compensation Plan

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

TETLP: Texas Eastern Transmission, LP

U.S.: The United States of America

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

PART I

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

Safe Harbor for Forward-Looking Statements

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

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

ITEM 1. Business.

Corporate Overview and Strategy

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

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

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

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

Operating Segments

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

Regulated Energy

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

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

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

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

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

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

Operational Highlights

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

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

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

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

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

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

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

Regulatory Overview

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

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

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

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

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

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

Weather

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

Competition

Natural Gas Distribution

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

Natural Gas Transmission

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

Electric Distribution

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

Supplies, Transmission and Storage

Natural Gas Distribution

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

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

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

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

A summary of our pipeline capacity contracts follows:

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

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

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

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

Electric Distribution

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

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

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

Unregulated Energy

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

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

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

Propane Operations

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

Propane Operations - Operational Highlights

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

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

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

Competition

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

Supplies, Transportation and Storage

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

Weather

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

Unregulated Energy Transmission (Aspire Energy)

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

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

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

Energy Generation (Eight Flags)

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

Energy Services (PESCO)

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

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

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

Marlin Gas Services

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

Other Businesses and Eliminations

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

Environmental Matters

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

Employees

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

Executive Officers

Set forth below are the names, ages, and positions of our executive officers with their recent business experience. The age of each officer is as of the filing date of this report.

Name	Age	Officer Since	Offices Held During the Past Five Years
Jeffry M. Householder	*61*	*2010*	*President (January 1, 2019 - present)* Chief Executive Officer (January 1, 2019 - present) Director (January 1, 2019 - present) President of FPU (June 2010 - February 26, 2019)
Beth W. Cooper	52	2005	Executive Vice President (Beginning February 26, 2019) Chief Financial Officer (September 2008 - present) Senior Vice President (September 2008 - February 26, 2019) Assistant Corporate Secretary (March 2015 - present) Corporate Secretary (June 2005 - March 2015)
James F. Moriarty	61	2015	Executive Vice President (Beginning February 26, 2019) General Counsel & Corporate Secretary (March 2015 - present) Chief Policy and Risk Officer (Beginning February 26, 2019) Senior Vice President (February 2017 - February 26, 2019) Vice President (March 2015 - February 2017)
Stephen C. Thompson	58	1997	Senior Vice President (September 2004 - present) President, Eastern Shore (January 1997 - present) President and Chief Operating Officer, Sandpiper (May 2014 - present) Vice President (May 1997 - September 2004)

Available Information on Corporate Governance Documents

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments to these reports that we file with or furnish to the SEC are available free of charge at our website, *www.chpk.com*, as soon as reasonably practicable after we electronically file these reports with, or furnish these reports to the SEC. The content of this website is not part of this report.

In addition, the following documents are available free of charge on our website, *www.chpk.com*:

- Business Code of Ethics and Conduct applicable to all employees, officers and directors;
- Code of Ethics for Financial Officers;
- Corporate Governance Guidelines;
- Charters for the Audit Committee, Compensation Committee, Investment Committee, and Corporate Governance Committee of the Board of Directors; and
- Corporate Governance Guidelines on Director Independence.

Any of these reports or documents may also be obtained by writing to: Corporate Secretary; c/o Chesapeake Utilities Corporation, 909 Silver Lake Boulevard, Dover, DE 19904.

ITEM 1A. RISK FACTORS.

The following is a discussion of the primary factors that may affect the operations and/or financial performance of our regulated and unregulated energy businesses. Refer to the section entitled *Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations* of this report for an additional discussion of these and other related factors that affect our operations and/or financial performance.

FINANCIAL RISKS

Instability and volatility in the financial markets could negatively impact access to capital at competitive rates, which could affect our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth.

Our business strategy includes the continued pursuit of growth and requires capital investment in excess of cash flow from operations. As a result, the successful execution of our strategy is dependent upon access to equity and debt at reasonable costs. Our ability to issue new debt and equity capital and the cost of equity and debt are greatly affected by our financial performance and the conditions of the financial markets. In addition, our ability to obtain adequate and cost-effective debt depends on our credit ratings. A downgrade in our current credit ratings could negatively impact our access to and cost of debt. If we are not able to access capital at competitive rates, our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth may be limited.

PESCO is exposed to market risks beyond our control, which could adversely affect our financial results and capital requirements.

PESCO is subject to market risks beyond our control, including market liquidity and commodity price volatility. Although we maintain a risk management policy, we may not be able to offset completely the price risk associated with volatile commodity prices, which could lead to volatility in earnings. Physical trading also has price risk on any net open positions at the end of each trading day, as well as volatility resulting from (i) intra-day fluctuations of natural gas prices, and (ii) daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is economically hedged. The determination of our net open position at the end of any trading day requires us to make assumptions as to future circumstances, including the use of natural gas by our customers in relation to anticipated market positions. Because the price risk associated with any net open position at the end of such day may increase if the assumptions are not realized, we review these assumptions daily. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner, because the changes in fair value of trading contracts are immediately recognized as profits or losses for financial accounting purposes. This volatility may occur, with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated.

PESCO is exposed to the credit risk of its counterparties.

PESCO extends credit to counterparties and continually monitors and manages collections aggressively. There is risk that PESCO may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform, and any underlying collateral is inadequate, we could experience financial losses, which would negatively impact our results of operations.

PESCO is dependent upon the availability of credit to successfully operate its business.

PESCO depends upon credit to buy natural gas for resale or to trade. If financial market conditions or the financial condition of our Company declines, then the cost of credit could increase or become unavailable, which might adversely affect our results of operations, cash flows and financial condition.

Fluctuations in propane gas prices could negatively affect results of operations.

We adjust the price of the propane we sell based on changes in our cost of purchasing propane. However, if the market does not allow us to increase propane sales prices to compensate fully for fluctuations in purchased gas costs, our results of operations and earnings could be negatively affected.

If we fail to comply with our debt covenant obligations, we could experience adverse financial consequences that could affect our liquidity and ability to borrow funds.

Our long-term debt obligations, term loans, the Revolver and our committed short-term lines of credit contain financial covenants related to debt-to-capital ratios and interest-coverage ratios. Failure to comply with any of these covenants could result in an event of default which, if not cured or waived, could result in the acceleration of outstanding debt obligations or the inability to borrow under certain credit agreements. Any such acceleration could cause a material adverse change in our financial condition.

Increases in interest rates may adversely affect our results of operations and cash flows.

Increases in interest rates could increase the cost of future debt issuances. Absent recovery of the higher debt cost in the rates we charge our utility customers, our earnings could be adversely affected. Increases in short-term interest rates could negatively affect our results of operations, which depend on short-term lines of credit to finance accounts receivable and storage gas inventories and to temporarily finance capital expenditures. Reference should be made to *Item 7A, Quantitative and Qualitative Disclosures about Market Risk* for additional information.

Current market conditions could adversely impact the return on plan assets for our pension plans, which may require significant additional funding.

Our pension plans are closed to new employees, and the future benefits are frozen. The costs of providing benefits and related funding requirements of these plans are subject to changes in the market value of the assets that fund the plans and the discount rates used to estimate the pension benefit obligations. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors that are subject to an inherent degree of uncertainty, particularly in the current economic environment. Future losses of asset values and further declines in discount rates may necessitate accelerated funding of the plans to meet minimum federal government requirements and may result in higher pension expense in future years. Adverse changes in the benefit obligations of our pension plans may require us to record higher pension expense and fund obligations earlier than originally planned, which would have an adverse impact on our cash flows from operations, decrease borrowing capacity and increase interest expense.

OPERATIONAL RISKS

We are dependent upon construction of new facilities to support future growth in earnings in our natural gas and electric distribution and natural gas transmission operations.

Construction of new facilities required to support future growth is subject to various regulatory and developmental risks, including but not limited to: (i) our ability to obtain timely certificate authorizations, necessary approvals and permits from regulatory agencies and on terms that are acceptable to us; (ii) potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project; (iii) our inability to acquire rights-of-way or land rights on a timely basis on terms that are acceptable to us; (iv) lack of anticipated future growth in available natural gas and electricity supply; (v) insufficient customer throughput commitments; and (vi) lack of available and qualified third-party contractors which could impact the timely construction of new facilities.

We operate in a competitive environment, and we may lose customers to competitors.

Natural Gas. Our natural gas transmission and distribution operations compete with interstate pipelines when our customers are located close enough to a competing pipeline to make direct connections economically feasible. Our natural gas marketing operations compete with third-party suppliers to sell natural gas to commercial and industrial customers. Customers also have the option to switch to alternative fuels, including renewable energy sources. Failure to retain and grow our natural gas customer base would have an adverse effect on our financial condition, cash flows and results of operations.

Electric. Our Florida electric distribution business has remained substantially free from direct competition from other electric service providers but does face competition from other energy sources. Changes in the competitive environment caused by legislation, regulation, market conditions, or initiatives of other electric power providers, particularly with respect to retail electric competition, could adversely affect our results of operations, cash flows and financial condition.

Propane. Our propane operations compete with other propane distributors, primarily on the basis of service and price. Some of our competitors have significantly greater resources. Our ability to grow the propane operations business is contingent upon capturing additional market share, expanding into new markets, and successfully utilizing pricing programs that retain and grow

our customer base. Failure to retain and grow our customer base in our propane operations would have an adverse effect on our results of operations, cash flows and financial condition.

Fluctuations in weather may cause a significant variance in our earnings.

Our natural gas distribution, propane operations and natural gas transmission operations, are sensitive to fluctuations in weather conditions, which directly influence the volume of natural gas and propane we transport, sell and deliver to our customers. A significant portion of our natural gas distribution, propane operations and natural gas transmission revenue is derived from the sales and deliveries to residential, commercial and industrial heating customers during the five-month peak heating season (November through March). Other than our Maryland division and Sandpiper Energy which have revenue normalization mechanisms, if the weather is warmer than normal, we sell and deliver less natural gas and propane to customers, and earn less revenue, which could adversely affect our results of operations, cash flows and financial condition. Likewise, if the weather is colder than normal, we sell and deliver more natural gas and propane to customers, and earn more revenue, which could positively affect our results of operations, cash flows and financial condition. Variations in weather from year to year can cause our results of operations, cash flows and financial condition to vary accordingly.

Our electric distribution operation is also affected by variations in weather conditions generally and unusually severe weather conditions. However, electricity consumption is generally less seasonal than natural gas and propane because it is used for both heating and cooling in our service areas.

Natural disasters, severe weather (such as a major hurricane) and acts of terrorism could adversely impact earnings.

Inherent in energy transmission and distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, fires, explosions, sabotage and mechanical problems. Natural disasters and severe weather may damage our assets, cause operational interruptions and result in the loss of human life, all of which could negatively affect our earnings, financial condition and results of operations. Acts of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas, electricity and propane that could negatively affect our operations. Companies in the energy industry may face a heightened risk of exposure to acts of terrorism, which could affect our earnings, financial condition and results of operations. The insurance industry may also be affected by natural disasters, severe weather and acts of terrorism; as a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms, which could adversely affect our results of operations, financial condition and cash flows.

Operating events affecting public safety and the reliability of our natural gas and electric distribution and transmission systems could adversely affect our operations and increase our costs.

Our natural gas and electric operations are exposed to operational events and risks, such as major leaks, outages, mechanical failures and breakdown, operations below the expected level of performance or efficiency, and accidents that could affect public safety and the reliability of our distribution and transmission systems, significantly increase costs and cause loss of customer confidence. If we are unable to recover all or some of these costs from insurance and/or customers through the regulatory process, our results of operations, financial condition and cash flows could be adversely affected.

A security breach disrupting our operating systems and facilities or exposing confidential information may adversely affect our reputation, disrupt our operations and increase our costs.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to system disruptions or cause facility shutdowns. If such an attack or security breach were to occur, our business, our earnings, results of operation and financial condition could be adversely affected. In addition, the protection of customer, employee and Company data is crucial to our operational security. A breach or breakdown of our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could have an adverse effect on our reputation, results of operations and financial condition and could also materially increase our costs of maintaining our system and protecting it against future breakdowns or breaches. We take reasonable precautions to safeguard our information systems from cyber-attacks and security breaches; however, there is no guarantee that the procedures implemented to protect against unauthorized access to our information systems are adequate to safeguard against all attacks and breaches.

Failure to attract and retain an appropriately qualified employee workforce could adversely affect operations.

Our ability to implement our business strategy and serve our customers depends upon our continuing ability to attract, develop and retain talented professionals and a technically skilled workforce, and transfer the knowledge and expertise of our workforce to new employees as our existing employees retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or the future availability and cost of contract labor could adversely affect our ability to manage and operate our business. If we were unable to hire, train and retain appropriately qualified personnel, our results of operations could be adversely affected.

A strike, work stoppage or a labor dispute could adversely affect our operations.

We are party to collective bargaining agreements with labor unions at some of our Florida operations. A strike, work stoppage or a labor dispute with a union or employees represented by a union could cause interruption to our operations and our results could be adversely affected.

Our businesses are capital-intensive, and the increased costs and/or delays of capital projects may adversely affect our future earnings.

Our businesses are capital-intensive and require significant investments in ongoing infrastructure projects. Our ability to complete our infrastructure projects on a timely basis and manage the overall cost of those projects may be affected by the availability of the necessary materials and qualified vendors. Our future earnings could be adversely affected if we are unable to manage such capital projects effectively, or if full recovery of such capital costs is not permitted in future regulatory proceedings.

Our regulated energy business may be at risk if franchise agreements are not renewed, or new franchise agreements are not obtained, which could adversely affect our future results or operating cash flows and financial condition.

Our regulated natural gas and electric distribution operations hold franchises in each of the incorporated municipalities that require franchise agreements in order to provide natural gas and electricity. Ongoing financial results would be adversely impacted in the event that franchise agreements were not renewed. If we are unable to obtain franchise agreements for new service areas, growth in our future earnings could be negatively impacted.

Slowdowns in customer growth may adversely affect earnings and cash flows.

Our ability to increase gross margins in our natural gas, propane and electric distribution businesses is dependent upon growth in the residential construction market, adding new commercial and industrial customers and conversion of customers to natural gas, electricity or propane from other energy sources. Slowdowns in growth may adversely affect our gross margin, earnings and cash flows.

Energy conservation could lower energy consumption, which would adversely affect our earnings.

Federal and state legislative and regulatory initiatives to promote energy efficiency and conservation could lower energy consumption by our customers. In addition, higher costs of natural gas, propane and electricity may cause customers to conserve fuel. To the extent a PSC or FERC does not allow the recovery through customer rates of the costs or lower consumption from energy efficiency or conservation, and our propane margins cannot be increased due to market conditions, our results of operations, cash flows and financial condition may be adversely affected.

Commodity price increases may adversely affect the operating costs and competitive positions of our natural gas, electric and propane operations, which may adversely affect our results of operations, cash flows and financial condition.

Natural Gas/Electricity. Higher natural gas prices can significantly increase the cost of gas billed to our natural gas customers. Increases in the cost of natural gas and other fuels used to generate electricity can significantly increase the cost of electricity billed to our electric customers. Damage to the production or transportation facilities of our suppliers, which decreases their supply of natural gas and electricity, could result in increased supply costs and higher prices for our customers. Such cost increases generally have no immediate effect on our revenues and net income because of our regulated fuel cost recovery mechanisms. However, our net income may be reduced by higher expenses that we may incur for uncollectible customer accounts and by lower volumes of natural gas and electricity deliveries when customers reduce their consumption. Therefore, increases in the price of natural gas and other fuels can adversely affect our operating cash flows, results of operations and financial condition, as well as the competitiveness of natural gas and electricity as energy sources.

Propane. Propane costs are subject to changes as a result of product supply or other market conditions, including weather, economic and political factors affecting crude oil and natural gas supply or pricing. For example, weather conditions could damage production

or transportation facilities, which could result in decreased supplies of propane, increased supply costs and higher prices for customers. Such increases in costs can occur rapidly and can negatively affect profitability. There is no assurance that we will be able to pass on propane cost increases fully or immediately, particularly when propane costs increase rapidly. Therefore, average retail sales prices can vary significantly from year-to-year as product costs fluctuate in response to propane, fuel oil, crude oil and natural gas commodity market conditions. In addition, in periods of sustained higher commodity prices, declines in retail sales volumes due to reduced consumption and increased amounts of uncollectible accounts may adversely affect net income.

Refer to *Item 7A, Quantitative and Qualitative Disclosures about Market Risk* for additional information.

A substantial disruption or lack of growth in interstate natural gas pipeline transmission and storage capacity or electric transmission capacity may impair our ability to meet customers' existing and future requirements.

In order to meet existing and future customer demands for natural gas and electricity, we must acquire sufficient supplies of natural gas and electricity, interstate pipeline transmission and storage capacity, and electric transmission capacity to serve such requirements. We must contract for reliable and adequate upstream transmission capacity for our distribution systems while considering the dynamics of the interstate pipeline and storage and electric transmission markets, our own on-system resources, as well as the characteristics of our markets. Our financial condition and results of operations would be materially and adversely affected if the future availability of these capacities were insufficient to meet future customer demands for natural gas and electricity. Currently, our Florida natural gas operation relies primarily on one pipeline system, FGT, for most of its natural gas supply and transmission. Our Florida electric operation secures electricity from external parties. Any continued interruption of service from these suppliers could adversely affect our ability to meet the demands of our customers, which could negatively impact our earnings, financial condition and results of operations.

Our use of derivative instruments may adversely affect our results of operations.

Fluctuating commodity prices may affect our earnings and financing costs because our propane operations and PESCO use derivative instruments, including forwards, futures, swaps, puts, and calls, to hedge price risk. While we have risk management policies and operating procedures in place to control our exposure to risk, if we purchase derivative instruments that are not properly matched to our exposure, our results of operations, cash flows, and financial condition may be adversely affected.

PESCO's earnings and operating cash flows are dependent upon optimization of physical assets.

PESCO's earnings and cash flows are based, in part, on its ability to optimize its portfolio of contractual rights to utilize natural gas storage and pipeline assets. The optimization strategy involves utilizing its physical assets to take advantage of differences in natural gas prices between geographic locations and/or time periods. Any change among various pricing points could affect those differentials. In addition, significant increases in the supply of natural gas for PESCO's market areas can reduce its ability to take advantage of pricing fluctuations in the future. Changes in pricing dynamics and supply could have an adverse impact on its optimization activities, earnings and cash flows. PESCO incurs fixed demand fees to acquire its contractual rights to storage and transportation assets. Should commodity prices at various locations or time periods change in such a way that PESCO is not able to recoup these costs from customers, the cash flows and earnings of PESCO and ultimately, the Company, could be adversely impacted.

REGULATORY, LEGAL AND ENVIRONMENTAL RISKS

Regulation of our businesses, including changes in the regulatory environment, may adversely affect our results of operations, cash flows and financial condition.

The Delaware, Maryland and Florida PSCs regulate our utility operations in those states. Eastern Shore is regulated by the FERC. The PSCs and the FERC set the rates that we can charge customers for services subject to their regulatory jurisdiction. Our ability to obtain timely future rate increases and rate supplements to maintain current rates of return depends on regulatory approvals, and there can be no assurance that our regulated operations will be able to obtain such approvals or maintain currently authorized rates of return. When earnings from our regulated utilities exceed the authorized rate of return, the respective regulatory authority may require us to reduce our rates charged to customers in the future.

We may face certain regulatory and financial risks related to pipeline safety legislation.

We are subject to a number of legislative proposals at the federal and state level to implement increased oversight over natural gas pipeline operations and facilities to inspect pipeline facilities, upgrade pipeline facilities, or control the impact of a breach of such facilities. Additional operating expenses and capital expenditures may be necessary to remain in compliance. If new legislation is adopted and we incur additional expenses and expenditures, our financial condition, results of operations and cash flows could

be adversely affected, particularly if we are not authorized through the regulatory process to recover from customers some or all of these costs and our authorized rate of return.

We are subject to operating and litigation risks that may not be fully covered by insurance.

Our operations are subject to the operating hazards and risks normally incidental to handling, storing, transporting, transmitting and delivering natural gas, electricity and propane to end users. From time to time, we are a defendant in legal proceedings arising in the ordinary course of business. We maintain insurance coverage for our general liabilities in the amount of $51 million, which we believe is reasonable and prudent. However, there can be no assurance that such insurance will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices.

Costs of compliance with environmental laws may be significant.

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These evolving laws and regulations may require expenditures over a long period of time to control environmental effects at our current and former operating sites, especially former MGP sites. To date, we have been able to recover, through regulatory rate mechanisms, the costs associated with the remediation of former MGP sites. However, there is no guarantee that we will be able to recover future remediation costs in the same manner or at all. A change in our approved rate mechanisms for recovery of environmental remediation costs at former MGP sites could adversely affect our results of operations, cash flows and financial condition.

Further, existing environmental laws and regulations may be revised, or new laws and regulations seeking to protect the environment may be adopted and be applicable to us. Revised or additional laws and regulations could result in additional operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable. Any such increase in compliance costs could adversely affect our financial condition and results of operations. Compliance with these legal obligations requires us to commit capital. If we fail to comply with environmental laws and regulations, even if such failure is caused by factors beyond our control, we may be assessed civil or criminal penalties and fines, which could impact our financial condition and results of operations. See *Item 8, Financial Statements and Supplementary Data* (see Note 20, *Environmental Commitments and Contingencies,* in the consolidated financial statements).

Unanticipated changes in our tax provisions or exposure to additional tax liabilities could affect our profitability and cash flow.

We are subject to income and other taxes in the U.S. Changes in applicable U.S. tax laws and regulations, or their interpretation and application, including the possibility of retroactive effect, could affect our tax expense and profitability. In addition, the final determination of any tax audits or related litigation could be materially different from our historical income tax provisions and accruals. Changes in our tax provision or an increase in our tax liabilities, due to changes in applicable law and regulations, the interpretation or application thereof, future changes in the tax rate or a final determination of tax audits or litigation, could have a material adverse effect on our financial position, results of operations or cash flows.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The direction of future U.S. climate change regulation is difficult to predict given the potential for policy changes under different Presidential administrations and Congressional leadership. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions. Even if federal efforts in this area slow, states may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our products. Federal or state legislative initiatives to implement renewable portfolio standards or to further subsidize the cost of solar, wind and other renewable power sources may change the demand for natural gas. We cannot predict the potential impact that such laws or regulations, if adopted, may have on our future business, financial condition or financial results.

Climate changes may impact the demand for our services in the future and could result in more frequent and more severe weather events, which ultimately could adversely affect our financial results.

Significant climatic change creates physical and financial risks for us. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Changes in energy use due to weather variations may affect our financial condition

through volatility and/or decreased revenues and cash flows. Extreme weather conditions require more system backups and can increase costs and system stresses, including service interruptions. Severe weather impacts our operating territories primarily through thunderstorms, tornadoes, hurricanes, and snow or ice storms. Weather conditions outside of our operating territories could also have an impact on our revenues and cash flows by affecting natural gas prices. To the extent the frequency of extreme weather events increases, this could increase our costs of providing services. We may not be able to pass on the higher costs to our customers or recover all the costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could adversely affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for lawsuits related to or against greenhouse gas emitters based on the claimed connection between greenhouse gas emissions and climate change, which could impact adversely our business, results of operations and cash flows.

Our certificate of incorporation and bylaws may delay or prevent a transaction that stockholders would view as favorable.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could delay, defer or prevent an unsolicited change in control of Chesapeake Utilities, which may negatively affect the market price of our common stock or the ability of stockholders to participate in a transaction in which they might otherwise receive a premium for their shares over the then current market price. These provisions may also prevent changes in management. In addition, our Board of Directors is authorized to issue preferred stock without stockholder approval on such terms as our Board of Directors may determine. Our common stockholders will be subject to, and may be negatively affected by, the rights of any preferred stock that may be issued in the future.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. Properties.

Offices and other operational facilities

We own or lease offices and other operational facilities in the following locations: Anne Arundel, Cecil, Dorchester, Somerset, Talbot, Wicomico, and Worcester Counties, Maryland; Kent, New Castle and Sussex Counties, Delaware; Accomack County, Virginia; Alachua, Brevard, Broward, Hendry, Jackson, Levy, Martin, Nassau, Okeechobee, Palm Beach, Polk and Volusia Counties, Florida; Orrville and Athens, Ohio; and Pittsburgh, Pennsylvania.

Regulated Energy Segment

We own approximately 1,594 miles of natural gas distribution mains (together with related service lines, meters and regulators) in Kent, New Castle and Sussex Counties, Delaware; and Caroline, Cecil, Dorchester, Wicomico and Worcester Counties, Maryland. We own approximately 2,862 miles of natural gas distribution mains (and related equipment) in Brevard, Broward, Citrus, Clay, DeSoto, Escambia, Gadsden, Gilchrist, Hernando, Hillsborough, Holmes, Indian River, Jackson, Liberty, Marion, Martin, Nassau, Okeechobee, Osceola, Palm Beach, Polk, Seminole, Suwannee, Union, Volusia and Washington Counties, Florida. In addition, we have adequate gate stations to handle receipt of the gas into each of the distribution systems. We also own approximately 97 miles of underground propane distribution mains in Worcester County, Maryland and facilities in Delaware and Maryland, which we use for propane-air injection during periods of peak demand.

We own and operate approximately 486 miles of natural gas transmission pipeline, extending from interconnects at Daleville, Honey Brook and Parkesburg, Pennsylvania; and Hockessin, Delaware, to 96 delivery points in southeastern Pennsylvania, Delaware and the eastern shore of Maryland and approximately 86 miles of natural gas transmission pipeline in Escambia, Indian River, Palm Beach, Pensacola, Polk, Suwannee and Volusia Counties, Florida. We also own approximately 45 percent of the 16-mile natural gas pipeline extending from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. The remaining 55 percent of the natural gas pipeline is owned by Peoples Gas.

We own and operate approximately 16 miles of electric transmission line located in Nassau County, Florida and approximately 905 miles of electric distribution line in Calhoun, Jackson, Liberty and Nassau Counties, Florida.

Unregulated Energy Segment

We own bulk propane storage facilities, with an aggregate capacity of approximately 7.1 million gallons, in Delaware, Maryland, Virginia, Pennsylvania, and Florida. These facilities are located on real estate that is either owned or leased by us.

We own approximately 204 miles of underground propane distribution mains in Delaware; Dorchester, Princess Anne, Queen Anne's, Somerset, Talbot, Wicomico and Worcester Counties, Maryland; Chester and Delaware Counties, Pennsylvania; and Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Marion, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

We own 16 natural gas gathering systems and approximately 2,700 miles of pipeline in central and eastern Ohio.

Florida liens

All of the assets owned by FPU are subject to a lien in favor of the holders of its first mortgage bond securing its indebtedness under its Mortgage Indenture and Deed of Trust. These assets are not subject to any other lien as all other debt is unsecured. FPU owns offices and facilities in the following locations: Alachua, Brevard, Broward, Citrus, Hendry, Jackson, Nassau, Okeechobee, Palm Beach and Volusia Counties, Florida. The FPU assets subject to the lien also include: 1,980 miles of natural gas distribution mains (and related equipment) in its service areas; 16 miles of electric transmission line located in Nassau County, Florida; 905 miles of electric distribution line located in Calhoun, Jackson, Liberty and Nassau Counties in Florida; propane storage facilities with a total capacity of 1.1 million gallons, located in south, central and north Florida; and 76 miles of underground propane distribution mains in Alachua, Brevard, Broward, Citrus, Duval, Hillsborough, Indian River, Marion, Martin, Nassau, Orange, Palm Beach, Polk, Seminole, St. Johns and Volusia Counties, Florida.

ITEM 3. Legal Proceedings.

See Note 21, *Other Commitments and Contingencies* to the Consolidated Financial Statements, which is incorporated into Item 3 by reference.

ITEM 4. Mine Safety Disclosures.

Not applicable.

PART II

ITEM 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Common Stock Dividends and Stockholder Information:

Chesapeake Utilities common stock is traded on the New York Stock Exchange ("NYSE") under the ticker symbol CPK. As of February 15, 2019, we had 2,253 holders of record of our common stock. We declared quarterly cash dividends on our common stock totaling $1.4350 per share in 2018 and $1.2800 per share in 2017, and have paid a cash dividend to our common stock stockholders for 58 consecutive years. Future dividend payments and amounts are at the discretion of our Board of Directors and will depend on our financial condition, results of operations, capital requirements, and other factors.

Indentures to our long-term debt contain various restrictions which limit our ability to pay dividends. FPU's first mortgage bonds, which are due in 2022, contain a similar restriction that limits the payment of dividends by FPU. Refer to *Item 8, Financial Statements and Supplementary Data* (see Note 13, *Long-Term Debt*, in the consolidated financial statements) for additional information.

Purchases of Equity Securities by the Issuer

The following table sets forth information on purchases by us or on our behalf of shares of our common stock during the quarter ended December 31, 2018.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
October 1, 2018 through October 31, 2018 [1]	430	$ 83.03	—	—
November 1, 2018 through November 30, 2018	—	—	—	—
December 1, 2018 through December 31, 2018	—	—	—	—
Total	430	$ 83.03	—	—

[1] In October 2018, we purchased shares of common stock on the open market for the purpose of reinvesting the dividend on shares held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Non-Qualified Deferred Compensation Plan. The Non-Qualified Deferred Compensation Plan is discussed in detail in *Item 8, Financial Statements and Supplementary Data* (see Note 17, *Employee Benefit Plans*, in the consolidated financial statements). During the quarter, 430 shares were purchased through the reinvestment of dividends.

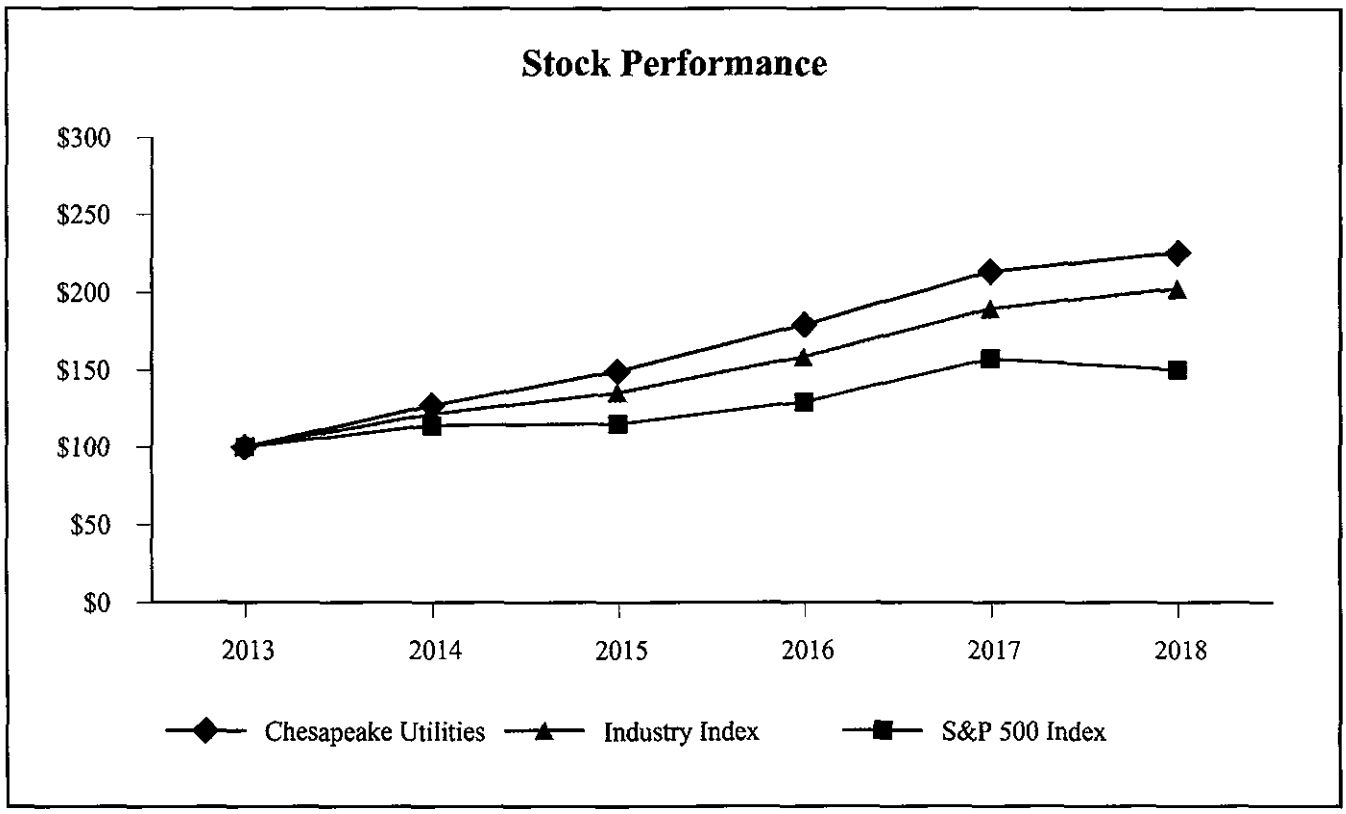
[2] Except for the purpose described in footnote [1], we have no publicly announced plans or programs to repurchase our shares.

Discussion of our compensation plans, for which shares of our common stock are authorized for issuance, is included in the section of our Proxy Statement captioned "Equity Compensation Plan Information" and is incorporated herein by reference.

Common Stock Performance Graph

The stock performance graph and table below compares cumulative total stockholder return on our common stock during the five fiscal years ended December 31, 2018, with the cumulative total stockholder return of the Standard & Poor's 500 Index and the cumulative total stockholder return of select peers, which include the following companies: Atmos Energy Corporation; Black Hills Corporation; New Jersey Resources Corporation; NiSource Inc.; Northwest Natural Holding Company; NorthWestern Corporation; ONE Gas Inc.; RGC Resources, Inc.; South Jersey Industries, Inc.; Spire Inc.; Unitil Corporation; and Vectren Corporation.

The comparison assumes $100 was invested on December 31, 2013 in our common stock and in each of the foregoing indices and assumes reinvested dividends. The comparisons in the graph below are based on historical data and are not intended to forecast the possible future performance of our common stock.



	2013	2014	2015	2016	2017	2018
Chesapeake Utilities	$ 100	$ 127	$ 149	$ 179	$ 213	**$ 225**
Industry Index	$ 100	$ 121	$ 135	$ 158	$ 189	**$ 202**
S&P 500 Index	$ 100	$ 114	$ 115	$ 129	$ 157	**$ 150**

ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,				
	2018	2017	2016	2015	2014
Operating					
(in thousands)					
Revenues					
Regulated Energy	$ 345,281	$ 326,310	$ 305,689	$ 301,902	$ 300,442
Unregulated Energy	420,617	324,595	203,778	162,108	184,961
Other businesses and eliminations	(48,409)	(33,322)	(10,607)	(4,766)	13,431
Total revenues	$ 717,489	$ 617,583	$ 498,860	$ 459,244	$ 498,834
Operating income[1]					
Regulated Energy	$ 79,215	$ 74,584	$ 71,515	$ 62,137	$ 51,173
Unregulated Energy	16,901	12,631	14,066	16,437	11,686
Other businesses and eliminations	(1,496)	205	402	418	104
Total operating income	$ 94,620	$ 87,420	$ 85,983	$ 78,992	$ 62,963
Net income from continuing operations	$ 56,580	$ 58,124	$ 44,675	$ 41,140	$ 36,092
Assets					
(in thousands)					
Gross property, plant and equipment	$ 1,569,683	$ 1,312,117	$ 1,175,595	$ 1,007,489	$ 870,125
Net property, plant and equipment	$ 1,383,972	$ 1,126,027	$ 986,664	$ 854,950	$ 689,762
Total assets	$ 1,693,671	$ 1,414,934	$ 1,229,219	$ 1,067,421	$ 904,469
Capital expenditures	$ 282,976	$ 191,103	$ 169,376	$ 195,261	$ 98,057
Capitalization					
(in thousands)					
Stockholders' equity	$ 518,439	$ 486,294	$ 446,086	$ 358,138	$ 300,322
Long-term debt, net of current maturities	316,020	197,395	136,954	149,006	158,486
Total capitalization	$ 834,459	$ 683,689	$ 583,040	$ 507,144	$ 458,808
Current portion of long-term debt	11,935	9,421	12,099	9,151	9,109
Short-term debt	294,458	250,969	209,871	173,397	88,231
Total capitalization and short-term financing	$ 1,140,852	$ 944,079	$ 805,010	$ 689,692	$ 556,148

(1) During the first quarter of 2018, we adopted amended FASB guidance on the presentation of net periodic and postretirement benefit cost ("net benefit cost"). As a result, the components of net benefit cost other than the service component are presented below the subtotal of Operating Income in the consolidated statements of income. All prior periods have been recast to conform to this presentation.

	For the Year Ended December 31,				
	2018	2017	2016	2015	2014
Common Stock Data and Ratios					
Basic earnings per share	$ 3.46	$ 3.56	$ 2.87	$ 2.73	$ 2.48
Diluted earnings per share	$ 3.45	$ 3.55	$ 2.86	$ 2.72	$ 2.47
Diluted earnings per share growth - 1 year	(2.8)%	24.1%	5.1%	10.1%	9.3%
Diluted earnings per share growth - 5 year	8.8 %	12.3%	8.4%	8.4%	11.6%
Diluted earnings per share growth - 10 year	10.1 %	10.7%	9.3%	8.4%	8.5%
Return on average equity	11.2 %	12.6%	11.3%	12.1%	12.2%
Common equity / total capitalization	62.1 %	71.1%	76.5%	70.6%	65.5%
Common equity / total capitalization and short-term financing	45.4 %	51.5%	55.4%	51.9%	54.0%
Capital expenditures / average total capitalization	37.3 %	30.2%	31.1%	29.5%	22.9%
Book value per share [1]	$ 31.65	$ 29.75	$ 27.36	$ 23.45	$ 20.59
Weighted average number of shares outstanding [1]	16,369,616	16,336,789	15,570,539	15,094,423	14,551,308
Shares outstanding at year-end [1]	16,378,545	16,344,442	16,303,499	15,270,659	14,588,711
Cash dividends declared per share [1]	$ 1.44	$ 1.28	$ 1.20	$ 1.13	$ 1.07
Dividend yield (annualized) [2]	1.8 %	1.7%	1.8%	2.0%	2.2%
Book yield [3]	4.7 %	4.5%	4.7%	5.1%	5.4%
Payout ratio [4]	41.6 %	36.0%	41.8%	41.5%	43.0%
Additional Data					
Customers					
Natural gas distribution	158,387	153,537	149,179	144,872	141,227
Electric distribution	32,185	32,026	31,695	31,430	31,272
Propane operations	56,915	54,760	54,947	53,682	53,272
Total employees	983	945	903	832	753

[1] Shares and per share amounts for all periods presented reflect the three-for-two stock split declared on July 2, 2014, effected in the form of a stock dividend, and distributed on September 8, 2014.
[2] Dividend yield (annualized) is calculated by multiplying the fourth quarter dividend by four (4), then dividing that amount by the closing common stock price at December 31.
[3] The book yield is calculated by dividing cash dividends declared per share (for the year) by average book value per share (for the year).
[4] The payout ratio is calculated by dividing cash dividends declared per share (for the year) by basic earnings per share.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

This section provides management's discussion of Chesapeake Utilities and its consolidated subsidiaries, with specific information on results of operations, liquidity and capital resources, as well as discussion of how certain accounting principles affect our financial statements. It includes management's interpretation of our financial results and our operating segments, the factors affecting these results, the major factors expected to affect future operating results as well as investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto in *Item 8, Financial Statements and Supplementary Data.*

Several factors exist that could influence our future financial performance, some of which are described in Item 1A, *Risk Factors*. They should be considered in connection with forward-looking statements contained in this report, or otherwise made by or on behalf of us, since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

The following discussions and those later in the document on operating income and segment results include the use of the term "gross margin," which is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities, and excludes depreciation, amortization and accretion. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by us under our allowed rates for regulated energy operations and under our competitive pricing structures for unregulated energy operations. Our management uses gross margin in measuring our business units' performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

Earnings per share information is presented on a diluted basis, unless otherwise noted.

OVERVIEW AND HIGHLIGHTS

(in thousands except per share data)			Increase			Increase
For the Year Ended December 31,	2018	2017	(decrease)	2017	2016	(decrease)
Operating Income:						
Regulated Energy	$ 79,215	$ 74,584	$ 4,631	$ 74,584	$ 71,515	$ 3,069
Unregulated Energy	16,901	12,631	4,270	12,631	14,066	(1,435)
Other businesses and eliminations	(1,496)	205	(1,701)	205	402	(197)
Total Operating Income	94,620	87,420	7,200	87,420	85,983	1,437
Other expense	(615)	(2,342)	1,727	(2,342)	(2,328)	(14)
Interest charges	16,431	12,645	3,786	12,645	10,639	2,006
Income Before Income Taxes	77,574	72,433	5,141	72,433	73,016	(583)
Income taxes	20,994	14,309	6,685	14,309	28,341	(14,032)
Net Income	$ 56,580	$ 58,124	$ (1,544)	$ 58,124	$ 44,675	$ 13,449
Earnings Per Share of Common Stock:						
Basic	$ 3.46	$ 3.56	$ (0.10)	$ 3.56	$ 2.87	$ 0.69
Diluted	$ 3.45	$ 3.55	$ (0.10)	$ 3.55	$ 2.86	$ 0.69

2018 compared to 2017

Our net income decreased by approximately $1.5 million or $0.10 per share in 2018, compared to 2017. Key variances included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2017 Reported Results	**$ 72,433**	**$ 58,124**	**$ 3.55**
Adjusting for unusual items:			
Absence of the 2017 deferred tax revaluation benefit associated with the TCJA	—	(14,299)	(0.87)
Net impact of PESCO's MTM activity	10,423	7,602	0.46
One-time separation expenses associated with a former executive	(1,548)	(1,421)	(0.09)
Absence of Xeron expenses, including 2017 wind-down expenses	829	605	0.04
	9,704	(7,513)	(0.46)
Increased (Decreased) Gross Margins:			
Eastern Shore and Peninsula Pipeline service expansions*	9,709	7,082	0.43
Pass-through of lower taxes to regulated energy customers[1]	(9,562)	(6,975)	(0.42)
Natural gas growth (excluding service expansions)	5,911	4,311	0.26
Implementation of Eastern Shore settled rates*[2]	5,803	4,233	0.26
Impact on PESCO from Bomb Cyclone and pipeline capacity constraints	(5,545)	(4,044)	(0.25)
Colder weather	5,046	3,680	0.22
Unregulated Energy growth, excluding PESCO	3,140	2,290	0.14
Florida electric reliability/modernization program*	1,516	1,106	0.07
Florida GRIP*	1,277	932	0.06
Other margin for PESCO operations (net)	(489)	(357)	(0.02)
	16,806	12,258	0.75
Decreased (Increased) Other Operating Expenses[3]:			
Depreciation, asset removal and property taxes	(4,779)	(3,486)	(0.21)
Payroll expense (increased staffing and annual salary increases)	(4,349)	(3,172)	(0.19)
Facilities maintenance costs	(2,687)	(1,960)	(0.12)
Operating expenses to increase staffing, infrastructure and risk management systems necessary to support growth for PESCO[3]	(2,665)	(1,944)	(0.12)
Outside services	(2,182)	(1,592)	(0.10)
Vehicle, other taxes and credit collections	(1,551)	(1,131)	(0.07)
Other employee-related expenses	(1,100)	(802)	(0.05)
Incentive compensation costs	734	535	0.03
Outside regulatory costs	661	482	0.03
Early termination of facility lease due to consolidation of operations facilities	(423)	(309)	(0.02)
	(18,341)	(13,379)	(0.82)
Interest charges	(3,786)	(2,762)	(0.17)
Income taxes - Regulated Energy [1]	—	6,975	0.42
Other income tax effects - primarily the impact of income rate tax changes on Unregulated businesses	—	2,323	0.14
Net Other changes	758	554	0.04
Year ended December 31, 2018 Reported Results	**$ 77,574**	**$ 56,580**	**$ 3.45**

[1] "Pass-through of lower taxes to regulated customers" represents the amounts that have already been refunded to customers or reserves established for future refunds and/or reduced rates to customers in 2018 as a result of lower taxes due to the TCJA. Refunds made to customers are offset by the corresponding decrease in federal income taxes expense and are expected to have no net impact on net income.

[2] Excluding amounts refunded to customers associated with the TCJA, which are broken out separately and discussed in footnote 1.

[3] As a result of increased staffing, infrastructure and risk management systems to support growth for PESCO, operating expenses for PESCO are presented separately.

*** See the Major Projects and Initiatives table.**

2017 compared to 2016

Our net income increased by approximately $13.4 million or $0.69 per share (diluted) in 2017, compared to 2016. Key variances included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Year ended December 31, 2016 Reported Results	$ 73,016	$ 44,675	$ 2.86
Adjusting for unusual items:			
Deferred tax revaluation benefit associated with the TCJA	—	14,299	0.87
Net impact of PESCO's MTM activity	(5,783)	(3,499)	(0.21)
Impact of winding down of Xeron operations and absence of 2016 loss	745	451	0.03
	(5,038)	11,251	0.69
Increased (Decreased) Gross Margins:			
Eight Flags' CHP plant	4,901	2,965	0.19
Implementation of new base rates for Eastern Shore*	3,693	2,234	0.14
PESCO - margin from operations	3,365	2,036	0.13
Natural gas growth (excluding service expansions)	2,818	1,705	0.11
Service expansions*	2,062	1,248	0.08
Florida GRIP*	1,902	1,151	0.07
Aspire Energy rates and management fees	1,125	680	0.04
Customer consumption (non-weather)	721	436	0.03
Implementation of Delaware Division settled rates	831	503	0.03
Wholesale propane sales and margins	678	410	0.03
Retail propane margins	645	390	0.02
Weather impact	578	350	0.02
Margin from Sandpiper System Improvement Rate	291	176	0.01
	23,610	14,284	0.90
(Increased) Decreased Other Operating Expenses:			
Payroll expense	(6,487)	(3,925)	(0.25)
Depreciation, asset removal and property tax costs due to new capital investments	(5,120)	(3,098)	(0.20)
Eight Flags' operating expenses	(2,920)	(1,767)	(0.11)
Benefit and other employee-related expenses	(1,485)	(899)	(0.06)
Regulatory expenses associated with rate filings	(1,005)	(608)	(0.04)
Taxes other than property and income	(739)	(447)	(0.03)
Credit, collections & customer service expenses	515	311	0.02
Outside services and facilities maintenance costs	417	252	0.02
Vehicle expenses	(372)	(225)	(0.01)
Sales and advertising expenses	(259)	(157)	(0.01)
	(17,455)	(10,563)	(0.67)
Increase in outstanding shares from the September 2016 public offering	—	—	(0.16)
Interest charges	(2,006)	(1,214)	(0.08)
Change in other expense	(191)	(115)	(0.01)
Change in effective tax rate prior to tax reform	—	(500)	(0.03)
Net other changes	497	306	0.05
Year ended December 31, 2017 Reported Results	**$ 72,433**	**$ 58,124**	**$ 3.55**

*** See the Major Projects and Initiatives table.**

SUMMARY OF KEY FACTORS

Recently Completed and Ongoing Major Projects and Initiatives

We constantly seek and develop additional projects and initiatives in order to increase shareholder value and serve our customers. The following table represents the major projects recently completed and currently underway. In the future, we will add new projects to this table as such projects are initiated:

	Gross Margin for the Period			
	Year Ended December 31,			Estimate for Fiscal
Project / Initiative	**2016**	**2017**	**2018**	**2019**
(in thousands)				
Florida GRIP	$ 11,552	$ 13,454	$ **14,731**	$ 16,276
Eastern Shore Rate Case [1]	—	3,693	**9,496**	9,800
Florida Electric Reliability/Modernization Pilot Program [1]	—	94	**1,610**	1,558
New Smyrna Beach, Florida[1]	—	235	**1,409**	1,409
2017 Eastern Shore System Expansion - including interim services [1]	—	483	**8,015**	15,709
Northwest Florida Expansion[1]	—	—	**3,485**	6,500
Western Palm Beach County, Florida Expansion[1]	—	—	**54**	1,250
Marlin Gas Services	—	—	**110**	4,475
Ohl propane acquisition (rolled into Sharp)	—	—	—	1,200
Total	$ 11,552	$ 17,959	$ **38,910**	$ 58,177

[1] Gross margin amount included in this table has not been adjusted to reflect the impact of the TCJA. The refunds and rate reductions implemented were or will be, offset by lower federal income taxes due to the TCJA.

Ongoing Growth Initiatives

Florida GRIP

Florida GRIP is a natural gas pipe replacement program approved by the Florida PSC that allows automatic recovery, through rates, of costs associated with the replacement of mains and services. Since the program's inception in August 2012, we have invested $127.0 million to replace 268 miles of qualifying distribution mains, including $13.3 million and $10.8 million during 2018 and 2017, respectively. GRIP generated additional gross margin of $1.3 million in 2018 compared to 2017.

Regulatory Proceedings

Eastern Shore Rate Case

Eastern Shore's rate case settlement agreement became final on April 1, 2018, with settlement rates effective August 1, 2017 and tax-adjusted rates effective January 1, 2018. The final agreement increases Eastern Shore's operating income by $6.6 million, representing an estimated $9.8 million in additional margin from base rates offset by an estimated $3.2 million in lower federal income tax expense for Eastern Shore resulting from the TCJA. In 2018, Eastern Shore recognized incremental gross margin of approximately $5.8 million and provided rate reductions to customers totaling approximately $3.3 million as a result of the new rates. Annual margin from the new rates in future years is estimated to be $9.8 million.

Florida Electric Reliability/Modernization Pilot Program

In December 2017, the Florida PSC approved a $1.6 million annualized rate increase, effective January 2018, for the recovery of a limited number of investments and costs related to reliability, safety and modernization for our Florida electric distribution system. This increase will continue through at least the last billing cycle of December 2019. For the years ended December 31, 2018 and 2017, incremental gross margin of $1.5 million and $94,000, respectively, was generated by this program.

Major Projects and Initiatives Currently Underway

New Smyrna Beach, Florida Project

In the fourth quarter of 2017, we commenced construction of a 14-mile natural gas transmission pipeline to serve current customers and planned customer growth in the New Smyrna Beach service area. A portion of the project was placed into service at the end of 2017, and the remainder was placed into service during the fourth quarter of 2018. For the year ended December 31, 2018, the project generated incremental gross margin of approximately $1.2 million compared to 2017 and is expected to generate $1.4 million in annual gross margin going forward.

2017 Eastern Shore System Expansion Project

From November 2017 to December 2018, Eastern Shore substantially completed the construction of a system expansion project that increased its capacity by 26 percent. The first phase of the project was placed into service in December 2017. The project generated $7.5 million in incremental gross margin, including margin from interim services, for the year ended December 31, 2018, compared to 2017. It is expected to produce annual gross margin of approximately $15.7 million in 2019, $15.8 million from 2020 through 2022 and $13.2 million thereafter.

Northwest Florida Expansion Project

In our first expansion of natural gas service into Northwest Florida, Peninsula Pipeline completed construction of transmission lines and the Florida natural gas division completed construction of lateral distribution lines to serve several customers. The project was placed into service in May 2018 and generated gross margin of $3.5 million during 2018. The estimated annual gross margin going forward is $6.5 million.

Western Palm Beach County Belvedere, Florida Project

Peninsula Pipeline is constructing four transmission lines to bring natural gas to our distribution system in West Palm Beach, Florida. The first phase of this project was placed into service in December 2018 and generated gross margin of $54,000 during 2018. We expect to complete the remainder of the project in phases through early 2020 and estimate gross margin of $1.3 million in 2019 and approximately $5.4 million in future years once fully in service.

Marlin Gas Services

In December 2018, Marlin Gas Services, our newly created subsidiary, acquired certain operating assets of Marlin Gas Transport, a supplier of mobile compressed natural gas utility and pipeline solutions. The acquisition will allow us to offer solutions to address supply interruption scenarios and provide other unique applications where pipeline supplies are not available or cannot meet customer requirements. Operating margins generated in 2018 were immaterial, given the date of acquisition. We estimate that this acquisition will generate additional annual gross margin of approximately $4.5 million in 2019, with potential for additional growth in future years.

Ohl Propane Acquisition

In December 2018, Sharp Energy acquired certain propane customers and operating assets of R.F. Ohl Fuel Oil, Inc ("Ohl"). Ohl provided propane distribution service to approximately 2,500 residential and commercial customers in Pennsylvania, located between two of Sharp's existing districts. The customers and assets acquired from Ohl have been assimilated into Sharp. Operating margins generated in 2018 were immaterial, given the date of acquisition. We estimate that this acquisition will generate additional gross margin of approximately $1.2 million for Sharp in 2019, with the potential for additional growth in future years.

Future Projects Not Included in the Table Above

Del-Mar Energy Pathway Project

In September 2018, Eastern Shore filed for FERC authorization to construct the Del-Mar Energy Pathway project to provide an additional 14,300 Dts/d of capacity to four customers. The benefits of this project include additional natural gas transmission pipeline infrastructure in eastern Sussex County, Delaware, and the initial extension of Eastern Shore's pipeline system into Somerset County, Maryland. The estimated annual gross margin from this project is $5.1 million. Eastern Shore anticipates that this project will be fully in-service by the third quarter of 2020, assuming that the FERC authorizes the project by August 2019.

Other Major Factors Influencing Gross Margin

Weather and Consumption

The impact of colder temperatures on customer consumption during 2018 contributed $5.0 million in incremental gross margin compared to 2017. While 2018 was colder than 2017, it was still 1.1 percent warmer than normal (average across our service territories). Normal weather during 2018 would have generated $4.0 million in additional gross margin. The following table summarizes HDD and CDD variances from the 10-year average HDD/CDD ("Normal") for 2018, 2017 and 2016.

HDD and CDD Information

For the Years Ended December 31,	2018	2017	Variance	2017	2016	Variance
Delmarva						
Actual HDD	**4,251**	3,800	451	3,800	3,979	(179)
10-Year Average HDD ("Normal")	**4,379**	4,374	5	4,374	4,453	(79)
Variance from Normal	**(128)**	(574)		(574)	(474)	
Florida						
Actual HDD	**780**	533	247	533	672	(139)
10-Year Average HDD ("Normal")	**800**	818	(18)	818	828	(10)
Variance from Normal	**(20)**	(285)		(285)	(156)	
Ohio						
Actual HDD	**5,845**	5,126	719	5,126	5,529	(403)
10-Year Average HDD ("Normal")	**5,823**	5,914	(91)	5,914	5,918	(4)
Variance from Normal	**22**	(788)		(788)	(389)	
Florida						
Actual CDD	**3,105**	3,013	92	3,013	3,152	(139)
10-Year Average CDD ("Normal")	**2,889**	2,865	24	2,865	2,820	45
Variance from Normal	**216**	148		148	332	

Hurricane Michael Update

In October 2018, Hurricane Michael passed through FPU's electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure resulting in 100 percent of its customers losing electrical service. FPU has restored service to those customers who were able to accept service following Hurricane Michael after a significant hurricane restoration effort. In conjunction with restoring these services, FPU expended over $60 million to restore service, which has been recorded as new plant and equipment or charged against FPU's accumulated depreciation and storm reserve. We have begun preparing the necessary regulatory filings to seek recovery for the costs incurred, including replenishment of our storm reserve. In conjunction with the hurricane-related expenditures, we executed two 13-month unsecured term loans as temporary financing, each in the amount of $30 million. The interest cost associated with these loans is LIBOR plus 75 basis points. One of the term loans was executed in December 2018 and the other was executed in January 2019. The storm did not have a material impact on our financial results in 2018 as services were restored to a majority of our customers, and is not expected to have a significant impact going forward as we will be seeking recovery of the storm costs through rates.

Natural Gas Distribution Customer and Consumption Growth

Customer growth for our natural gas distribution operations generated $3.9 million in additional gross margin for the year ended December 31, 2018 compared to the same period in 2017. The additional margin was generated from an increase of approximately 3.3 percent in the average number of residential customers served, growth in volumes delivered to commercial and industrial customers on the Delmarva Peninsula and in Florida, and new service initiated to customers in Northwest Florida. Higher residential and commercial customers' consumption increased gross margin by $2.0 million for the year ended December 31, 2018 compared to the same period in 2017.

(in thousands)	Increase (decrease) in Margin in 2018
Customer growth:	
Residential	$ 1,604
Commercial and industrial, excluding new service in Northwest Florida	1,322
New service in Northwest Florida	987
Total customer growth	3,913
Volume growth:	
Residential	655
Commercial and industrial	1,522
Other - including unbilled revenue	(179)
Total volume growth	1,998
Total natural gas distribution growth	$ 5,911

Propane Operations

The Company's Florida and Mid-Atlantic propane distribution operations continue to pursue a multi-pronged growth plan, which includes: targeting retail and wholesale customer growth in existing markets, both organically as well as through acquisitions; incremental growth from recent and planned start-ups in new markets; targeting new community gas systems in high growth areas; further build-out of the Company's propane vehicular platform through AutoGas fueling stations; and optimization of its supply portfolio to generate incremental margin opportunities. Our propane operations and AutoGas segment install and support propane vehicle conversion systems for vehicle fleets, including converting fleets to bi-fuel propane-powered engines and providing on-site fueling infrastructure. These operations generated $4.9 million during the year ended December 31, 2018 compared to 2017. Colder temperatures accounted for $2.2 million of the margin increase. The balance of the gross margin increase for the year reflected the impact of the growth strategies discussed above, including generating approximately a four-percent increase in customers. Supply management initiatives have also increased retail propane margins from many customer classes and margin from wholesale propane sales.

PESCO

In 2018, PESCO's gross margin increased by $4.4 million compared to 2017. Higher gross margin in 2018 from PESCO resulted from the following:

(in thousands)	Margin Impact
Net impact of PESCO's MTM activity	$ 10,423
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [1]	(3,284)
Loss for the Mid-Atlantic retail portfolio caused by pipeline capacity constraints in January and warm weather in February 2018 [1]	(2,261)
Other margin for PESCO operations (net)	(489)
Total Change in Gross Margin for PESCO in 2018	$ 4,389

[1] The 2018 Bomb Cyclone refers to the high-intensity winter storms in early January 2018 that impacted the Mid-Atlantic region and which had a residual impact on our businesses through the month of February. The exceedingly high demand and associated impacts on pipeline capacity and gas supply in the Mid-Atlantic region created significant, unusual costs for PESCO. While such concerted impacts will recur infrequently, our management revisited and refined its risk management strategies and implemented additional controls.

For the year ended December 31, 2018, PESCO reported an operating loss of $1.4 million, compared to an operating loss of $3.1 million during the prior year period. The year-over-year improvement in operating loss reflects primarily increased gross margin of $4.4 million, for the reasons discussed in the table above, which was offset by an increase of $2.7 million in other operating expenses as a result of increased staffing, infrastructure and risk management system costs to ensure the appropriate infrastructure is in place as PESCO executes its growth strategy.

Xeron

Xeron's operations were wound down during the second quarter of 2017. Operating income in 2018 improved by $718,000 over 2017, due to the absence of an operating loss and wind-down expenses incurred in 2017.

REGULATED ENERGY

For the Year Ended December 31, (in thousands)	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
Revenue	$ 345,281	$ 326,310	$ 18,971	$ 326,310	$ 305,689	$ 20,621
Cost of sales	121,828	118,769	3,059	118,769	109,609	9,160
Gross margin	223,453	207,541	15,912	207,541	196,080	11,461
Operations & maintenance	97,741	90,931	6,810	90,931	86,434	4,497
Gain from a settlement	(130)	(130)	—	(130)	(130)	—
Depreciation & amortization	31,876	28,554	3,322	28,554	25,677	2,877
Other taxes	14,751	13,602	1,149	13,602	12,584	1,018
Other operating expenses	144,238	132,957	11,281	132,957	124,565	8,392
Operating Income	$ 79,215	$ 74,584	$ 4,631	$ 74,584	$ 71,515	$ 3,069

2018 compared to 2017

Operating income for the Regulated Energy segment for 2018 was $79.2 million, an increase of $4.6 million, or 6.2 percent, compared to 2017. Adjusting for the estimated pass-through of lower taxes to customers, operating income increased by $14.2 million or 19.0 percent, compared to the prior year. The growth in operating income was due to an increase in gross margin of $15.9 million, $25.5 million adjusted for the tax pass-through, partially offset by $11.3 million in higher other operating expenses to support the margin growth. Growth in 2018 was strong across all business units in the regulated energy segment with the most significant contributions coming from expansions at Peninsula Pipeline and Eastern Shore, customer and consumption growth in the natural gas distribution operations, colder weather, and safety and reliability investments in the Florida electric and gas distribution operations.

Gross Margin

Items contributing to the year-over-year gross margin increase are listed in the following table:

(in thousands)	Margin Impact
Eastern Shore and Peninsula Pipeline service expansions	$ 9,709
Natural gas growth (excluding service expansions)	5,911
Implementation of Eastern Shore settled rates	5,803
Colder weather	1,788
Florida electric reliability/modernization program	1,516
Florida GRIP	1,277
Other	(530)
Total	25,474
Less: Pass-through to regulated customers of lower taxes as a result of the TCJA*	(9,562)
Year-over-year increase in gross margin	**$ 15,912**

*As a result of the TCJA and resulting directives by federal and state regulatory commissions, we reserved or refunded to customers of our regulated businesses an estimated $9.6 million in 2018. In some jurisdictions, we have paid refunds to customers, while in other jurisdictions, we have established reserves until agreements are approved and changes are made to customer rates. The reserves and lower customer rates are equal to the estimated reduction in federal income taxes due to the TCJA and have no material impact on after-tax earnings from the Regulated Energy segment.

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Service Expansions

The following natural gas pipeline service expansions generated additional gross margin of $9.7 million in 2018:

- $7.5 million from Eastern Shore's services, including those provided to customers on an interim basis, in conjunction with portions of Eastern Shore's 2017 Expansion Project that were placed in service, partially offset by the absence of $2.0 million in short-term contracts that were replaced by long-term service agreements; and
- $4.7 million generated by Peninsula Pipeline from the New Smyrna Beach and Northwest Pipeline Expansion Projects.

Natural Gas Growth (excluding service expansions)
We generated increased gross margin of $5.9 million in 2018 from natural gas growth and consumption (excluding service expansions) primarily from the following:

- $2.3 million and $1.6 million, respectively, from residential and commercial customer growth in Florida and on the Delmarva Peninsula; and
- $2.0 million from higher sales volumes (consumption) on the Delmarva Peninsula and in Florida that were not driven by weather.

Implementation of Eastern Shore's Settled Rates
Eastern Shore generated additional gross margin of $5.8 million from the implementation of new rates as a result of its rate case filing. See *Note 19, Rates and Other Regulatory Activities*, to the consolidated financial statements for additional details.

Colder Weather
Temperatures during 2018 were 1.1 percent warmer than normal (average across our service territories), compared to 14.8 percent warmer than normal (average across our service territories) during 2017. The colder weather increased usage and generated $1.8 million in additional margin for 2018.

Florida Electric Reliability/Modernization Program
This program generated incremental gross margin of $1.5 million in 2018. See *Note 19, Rates and Other Regulatory Activities,* to the consolidated financial statements for additional details.

Florida GRIP
Continued investment in the Florida GRIP generated additional gross margin of $1.3 million in 2018 compared to 2017.

Impact of the TCJA on Customer Rates
Implementation of the TCJA in 2018, decreased gross margin by $9.6 million due to refunds and reserves for future refunds and/ or rate reductions to customers. The decrease in gross margin was offset by an equal reduction in federal income taxes, and, therefore had no impact on net income. See Note 19, *Rates and Other Regulatory Activities*, for additional discussion of the TCJA impact.

Other Operating Expenses

Other operating expenses increased by $11.3 million, incurred primarily to support business growth. The significant factors contributing to the increase in other operating expenses included:

- $4.2 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $2.4 million in higher payroll expenses related to staffing and salary increases. This increase was partially offset by lower incentive compensation costs of $737,000;
- $2.2 million in higher costs related to outside services to support growth;
- $1.7 million in higher facilities and maintenance costs to maintain system integrity;
- $869,000 in higher vehicle, other taxes and credit collections; and
- $514,000 in other employee-related expenses.

2017 compared to 2016

Operating income for the Regulated Energy segment for 2017 was $74.6 million, an increase of $3.1 million, or 4.3 percent, compared to 2016. The increased operating income was due to an increase in gross margin of $11.5 million, partially offset by higher other operating expenses of $8.4 million.

Gross Margin

Items contributing to the year-over-year gross margin increase are listed in the following table:

(in thousands)	Margin Impact
Implementation of Eastern Shore rates	$ 3,693
Natural gas growth (including customer and consumption growth but excluding service expansions)	2,818
Eastern Shore and Peninsula Pipeline service expansions	2,062
Florida GRIP	1,902
Implementation of Delaware Division rates (2017 Settlement)	831
New natural gas transmission and distribution service to Eight Flags CHP plant	537
Other	(382)
Year-over-year increase in gross margin	$ 11,461

The following is a narrative discussion of significant items in the foregoing table for which we have additional information that we believe is necessary to understand the information disclosed in the table.

Implementation of Eastern Shore Rates
Eastern Shore generated additional gross margin of $3.7 million from implementation of new base rates in 2017 as a result of its rate case filing. See *Note 19, Rates and Other Regulatory Activities*, to the consolidated financial statements for additional details.

Natural Gas Growth (including customer and consumption growth but excluding service expansions)
In 2017, growth in customers and consumption generated increased gross margin of $2.8 million including:

- $1.6 million from a 3.8 percent increase in the average number of residential customers served by the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers served; and
- $1.2 million from our Florida natural gas distribution operations' customer growth, with approximately two-thirds of the margin growth generated from commercial and industrial customers and one-third generated from new residential customers.

Service Expansions
We generated additional gross margin of $2.1 million in 2017 from the following natural gas services:

- $1.2 million from short-term firm service available through Eastern Shore's natural gas receipt capacity from TETLP;
- $433,000 from interim services provided by Eastern Shore after a portion of an expansion project was placed in service in December 2017;
- $298,000 from Eastern Shore's increased long-term firm service rates for an industrial customer in Delaware; and
- $235,000 generated by Peninsula Pipeline from the New Smyrna Beach Expansion Project.

Florida GRIP
Increased investment in GRIP generated additional gross margin of $1.9 million in 2017 compared to 2016.

Implementation of Delaware Division Rates
Our Delaware Division generated additional gross margin of $831,000 as a result of its rate case settlement in 2017.

Service to Eight Flags
We generated additional gross margin of $537,000 in 2017, compared to 2016, from new natural gas transmission and distribution services provided to Eight Flags' CHP plant.

Other Operating Expenses

Other operating expenses increased by $8.4 million. The significant components of the increase in other operating expenses included:

- $4.1 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $3.6 million in higher payroll expenses for additional personnel to support growth; and
- $1.0 million in increased regulatory expenses, due primarily to costs associated with Eastern Shore's rate case filing in 2017; which was partially offset by
- $529,000 in lower credit, collection and customer services expenses.

UNREGULATED ENERGY

For the Year Ended December 31,	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
(in thousands)						
Revenue	$ 420,617	$ 324,595	$ 96,022	$ 324,595	$ 203,778	$ 120,817
Cost of sales	336,819	252,023	84,796	252,023	138,816	113,207
Gross margin	83,798	72,572	11,226	72,572	64,962	7,610
Operations & maintenance	54,263	48,576	5,687	48,576	42,437	6,139
Depreciation & amortization	8,845	7,954	891	7,954	6,386	1,568
Other taxes	3,789	3,411	378	3,411	2,073	1,338
Other operating expenses	66,897	59,941	6,956	59,941	50,896	9,045
Operating Income	$ 16,901	$ 12,631	$ 4,270	$ 12,631	$ 14,066	$ (1,435)

2018 Compared to 2017

Operating income for the Unregulated Energy segment for 2018 was $16.9 million, an increase of $4.3 million compared to 2017. The increased operating income was due to an increase in gross margin of $11.2 million, which was partially offset by an increase of $7.0 million in other operating expenses.

Given the impact of the MTM gain and loss recorded by PESCO in the first quarter of 2018 and fourth quarter of 2017, respectively, and the increased staffing, infrastructure and risk management systems implemented to support PESCO's growth, the Company is continuing to present PESCO's 2018 results separate from the rest of its Unregulated Energy segment:

Unregulated Energy, excluding PESCO

For the Year Ended December 31,	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
(in thousands)						
Gross margin	$ 77,197	$ 70,360	$ 6,837	$ 70,360	$ 60,332	$ 10,028
Depreciation, amortization and property taxes	9,678	9,081	597	9,081	7,047	2,034
Other operating expenses	49,197	45,504	3,693	45,504	41,085	4,419
Operating Income	$ 18,322	$ 15,775	$ 2,547	$ 15,775	$ 12,200	$ 3,575

Gross Margin

Items contributing to the year-over-year increase in gross margin are listed in the following table:

(in thousands)	Margin Impact
Propane Operations	
Customer growth, increased sales volumes (non-weather related) and other factors	2,947
Additional customer consumption from colder weather	2,241
Decreased margins per gallon in certain customer classes	(977)
Service, appliances and other fees	404
Higher wholesale propane margins and sales	287
Aspire Energy	
Higher customer consumption from colder weather	1,017
Increase in rates effective on various dates in 2018	602
Other	316
Year-over-year increase in gross margin	**$ 6,837**

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Propane Operations - Increased Margin Driven by Growth and Other Factors
Gross margin increased by $2.9 million, due to increased propane sales as a result of customer growth, higher sales volumes and other factors in Florida and the Mid-Atlantic region.

Propane Operations - Increased Customer Consumption - (Weather)
Gross margin increased by $2.2 million, due primarily to increased customer consumption in the Mid-Atlantic region as a result of colder temperatures in 2018 compared to 2017.

Aspire Energy - Increased Customer Consumption (Weather)
Gross margin increased by $1.0 million, as a result of increased natural gas delivered, due primarily to colder temperatures in 2018 when compared to temperatures in 2017.

Propane Operations - Decreased retail margins per gallon for certain customer classes
Gross margin decreased by $1.0 million, driven by lower sales prices for primarily two customer classes in response to market conditions.

Propane Operations - Services, appliances and other fees
Gross margin increased by $404,000, from services, appliances and other fees.

Aspire Energy - Increased Margin Driven by Changes in Rates
Gross margin increased by $602,000, due primarily to changes in customer rates on various dates during 2018.

Wholesale Propane Margins
Gross margin increased by $287,000, in 2018 due to a higher realized margin per gallon and an increase in volumes delivered for the Mid-Atlantic propane operations.

PESCO

For the Year Ended December 31,	2018	2017	Increase (decrease)	2017	2016	Increase (decrease)
(in thousands)						
Gross margin	$ 6,601	$ 2,212	$ 4,389	$ 2,212	$ 4,630	$ (2,418)
Depreciation, amortization and property taxes	604	206	398	206	18	188
Other operating expenses	7,418	5,150	2,268	5,150	2,746	2,404
Operating Income	$ (1,421)	$ (3,144)	$ 1,723	$ (3,144)	$ 1,866	$ (5,010)

In 2018, PESCO's gross margin increased by $4.4 million compared to 2017. Higher gross margin in 2018 from PESCO resulted from the following:

(in thousands)	Margin Impact
Net impact of PESCO's MTM activity	$ 10,423
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [1]	(3,284)
Loss for the Mid-Atlantic retail portfolio caused by pipeline capacity constraints in January and warm weather in February 2018 [1]	(2,261)
Other margin for PESCO operations (net)	(489)
Total Change in Gross Margin for PESCO in 2018	$ 4,389

[1] The 2018 Bomb Cyclone refers to the high-intensity winter storms in early January 2018 that impacted the Mid-Atlantic region and which had a residual impact on our businesses through the month of February. The exceedingly high demand and associated impacts on pipeline capacity and gas supply in the Mid-Atlantic region created significant, unusual costs for PESCO. While such concerted impacts are not expected to occur frequently, our management revisited and refined its risk management strategies and implemented additional controls.

Other Operating Expenses

Other operating expenses increased by $7.0 million in 2018 compared to 2017. The significant components of the increase in operating expenses included:

- $2.7 million in higher expenses as a result of increased staffing, infrastructure and risk management system costs to ensure the appropriate infrastructure is in place as PESCO executes its growth strategy;
- $1.9 million in higher payroll expense for additional personnel to support growth and increased deliveries driven by the colder weather in 2018 compared to 2017;
- $953,000 in higher facilities maintenance costs as a result of ongoing compliance activities;
- $597,000 in higher depreciation, amortization and property tax expense due to increased investments; and
- $586,000 in other employee-related costs.

2017 Compared to 2016

Operating income for the Unregulated Energy segment for 2017 was $12.6 million, a decrease of $1.4 million compared to 2016. The decreased operating income was due to an increase in gross margin of $7.6 million, which was offset by an increase of $9.0 million in other operating expenses. Gross margin and operating income, excluding the impact of the unrealized MTM loss on energy-related derivatives, grew by $13.4 million, or 20.6 percent, and $4.3 million, or 30.9 percent, respectively, during 2017, compared to 2016.

Gross Margin

Items contributing to the year-over-year increase in gross margin are listed in the following table:

(in thousands)	Margin Impact
PESCO - unrealized MTM loss	$ (5,783)
Eight Flags' CHP plant	4,365
PESCO - margin from operations	3,365
Customer consumption - weather and other	2,144
Pricing amendments to Aspire Energy's long-term sales agreements	1,125
Higher wholesale propane sales and margins	678
Wind-down of Xeron operations	658
Improved retail propane margins	645
Other	413
Year-over-year increase in gross margin	$ 7,610

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Natural Gas Marketing - PESCO

PESCO's gross margin decreased by $2.4 million due primarily to $5.8 million in the unrealized MTM loss related to PESCO's financial derivatives contracts that were valued at the end of the year; offset by $3.4 million in additional gross margin generated primarily from: (a) providing natural gas to end users within one customer pool pursuant to a supplier agreement with Columbia Gas of Ohio, which expired on March 31, 2017, and (b) an increase in commercial and industrial customers served in Florida.

Eight Flags

Eight Flags' CHP plant generated $4.4 million in additional gross margin in 2017 during its first full year of operations.

Customer Consumption - Weather and Other

Gross margin increased by $2.1 million due to higher, non-weather related sales volumes for our propane operations, increased weather driven demand at Aspire Energy and for our Mid-Atlantic propane operations in the fourth quarter and for our Florida propane operations during the third quarter of 2017.

Pricing Amendments to Aspire Energy's Long-Term Agreements

An increase in gross margin of $1.1 million due to favorable pricing amendments to several long-term sales agreements.

Wholesale Propane Sales and Margins

Gross margin increased by $678,000, due primarily to increased volumes and favorable supply management activities for the Mid-Atlantic propane operations, as well as higher margins in Florida.

Wind-down of Xeron operations

The absence of the prior year operating loss from Xeron increased gross margin by $658,000.

Retail Propane Margins

Gross margin increased by $645,000, due primarily to favorable supply management activities and market conditions.

Other Operating Expenses

Other operating expenses increased by $9.0 million. The significant components of the increase in other operating expenses included:

- $2.9 million in higher operating expenses by Eight Flags' CHP plant in support of the margin generated;
- $2.9 million in higher payroll costs for additional personnel to support growth;
- $1.0 million in higher depreciation expense, of which $476,000 relates to lower depreciation recorded in 2016 as a result of the final accounting for the acquisition of Aspire Energy;

- $1.0 million in higher benefits and employee-related costs in 2017; and
- $594,000 in higher taxes, other than property and income taxes.

OTHER EXPENSE, NET

Other expense, net for 2018 was $615,000, and was $2.3 million for both 2017 and 2016. Other expense, net includes non-operating investment income (expense), interest income, late fees charged to customers, gains or losses from the sale of assets for our unregulated business and pension and other benefits expense. The decrease in other expense, net in 2018 was due to a decrease in pension expenses when compared to 2017 and the absence of a lease termination payment which occurred in 2017.

INTEREST CHARGES

2018 Compared to 2017

Interest charges for 2018 increased by approximately $3.8 million, compared to 2017. The increase is attributable $3.3 million in additional interest due to higher short-term borrowings and higher short-term interest rates as well as $1.5 million in additional interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017 and the NYL Shelf Notes (Series A) in May 2018. These increases were partially offset by allowance for funds used during construction ("AFUDC") of approximately $1.1 million, primarily from Eastern Shore and Peninsula Pipeline.

2017 Compared to 2016

Interest charges for 2017 increased by approximately $2.0 million compared to 2016. The increase is attributable to $1.3 million in additional interest due to higher short-term borrowings and $1.0 million in additional interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017. The balance of the increase reflects higher interest expense on customer deposits.

INCOME TAXES

2018 Compared to 2017

Income tax expense was $21.0 million for 2018 compared to $14.3 million for 2017. The increase in income tax expense in 2018 was due primarily to enactment of the TCJA in 2017, which resulted in a one-time decrease in our deferred income tax expense for 2017 by $14.3 million. Our effective income tax rate was 27.1 percent in 2018 compared to 19.8 percent in 2017. Our lower effective tax rate in 2017 resulted from the one-time revaluation of deferred tax assets and liabilities from our Unregulated Energy business as a result of the enactment of the TCJA.

2017 Compared to 2016

Income tax expense was $14.3 million for 2017, compared to $28.3 million in 2016. Our effective tax rate was 19.8 percent in 2017, compared to 38.8 percent in 2016. The lower tax expense and effective tax rate in 2017 was due primarily to enactment of the TCJA in December 2017.

LIQUIDITY AND CAPITAL RESOURCES

Capital expenditures for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures were $283.0 million in 2018 (including the purchase of certain assets from Marlin CNG Services and Ohl), $191.1 million in 2017 (including the purchase of certain assets of ARM) and $169.4 million in 2016. The 2018 capital expenditures also includes over $60.0 million of restoration costs associated with repairing damages caused by Hurricane Michael to our electric distribution operations' service territory in Northwest Florida.

The following table shows the 2019 capital expenditure budget of $168.2 million by segment and by business line:

(dollars in thousands)	Budget Capital Expenditures
Regulated Energy:	
Natural gas distribution	$ 64,143
Natural gas transmission	66,787
Electric distribution	5,949
Total Regulated Energy	136,879
Unregulated Energy:	
Propane operations	11,870
Energy transmission	8,345
Other unregulated energy	1,416
Total Unregulated Energy	21,631
Other:	
Corporate and other businesses	9,705
Total Other	9,705
Total 2019 capital expenditures budget	**$ 168,215**

The 2019 budget, excluding acquisitions, includes: Eastern Shore's Del-Mar Energy Pathway Project, Florida's Palm Beach County Western Expansion and other potential pipeline projects, continued expenditures under Florida GRIP, further expansions of our natural gas distribution and transmission systems, continued natural gas infrastructure improvement activities, information technology systems, new buildings and facilities, and other strategic initiatives and investments.

The capital expenditure projection is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities, availability of capital and other factors discussed in Item 1A. Risk Factors. Over the last five years, our actual capital expenditures have averaged 98 percent of the initial budgeted capital expenditures for those years.

The timing of capital expenditures can vary based on delays in regulatory approvals, securing environmental approvals and other permits. The regulatory application and approval process has lengthened in the past few years, and we expect this trend to continue.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings. This commitment, along with adequate and timely rate relief for our regulated energy operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost, which will benefit our customers, creditors, employees and stockholders.

Our capitalization as of December 31, 2018 and 2017 follows:

(in thousands)	December 31, 2018		December 31, 2017	
Long-term debt, net of current maturities	**$ 316,020**	**38%**	$ 197,395	29%
Stockholders' equity	**518,439**	**62%**	486,294	71%
Total capitalization, excluding short-term borrowings	**$ 834,459**	**100%**	$ 683,689	100%

(in thousands)	December 31, 2018		December 31, 2017	
Short-term debt	**$ 294,458**	**26%**	$ 250,969	26%
Long-term debt, including current maturities	**327,955**	**29%**	206,816	22%
Stockholders' equity	**518,439**	**45%**	486,294	52%
Total capitalization, including short-term borrowings	**$ 1,140,852**	**100%**	$ 944,079	100%

Included in the long-term debt balances at December 31, 2018, were capital lease obligations for Sandpiper and Sharp. Sandpiper maintains a capacity, supply and operating agreement ($620,000 of current maturities) that expires in May 2019. The capacity portion of this agreement is accounted for as a capital lease. Our Mid-Atlantic propane operations business unit has entered into an agreement to rent property in Anne Arundel County Maryland which it intends to purchase during the first quarter of 2019 ($690,000 of current maturities).

As of December 31, 2018, we had no restrictions on our cash balances. Chesapeake Utilities' Senior Notes and FPU's first mortgage bonds contain a restriction that limits the payment of dividends or other restricted payments in excess of certain pre-determined thresholds. As of December 31, 2018, $242.8 million of our consolidated net income and $118.2 million of FPU's net income were free of such restrictions.

Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. Including the funds expended specifically related to the impact of Hurricane Michael, our equity to total capitalization ratio, including short-term borrowings, was 45 percent as of December 31, 2018. Excluding the funds expended for Hurricane Michael restoration activities, our equity to total capitalization ratio, including short-term borrowings, would have been approximately 48 percent.

As described below under "Short-Term Borrowings," we have a Revolver with borrowing capacity of $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we also entered into long-term shelf agreements for the potential private placement of unsecured senior debt as further described below under the heading "Shelf Agreements."

We will seek to align, as much as feasible, any long-term debt or equity issuance(s) with the commencement of service and associated earnings for larger revenue generating capital projects and considering market conditions.

Shelf Agreements

We have entered into Shelf Agreements with Prudential, MetLife and NYL who are under no obligation to purchase any unsecured debt. The proceeds received from the issuances of these shelf notes was used to reduce borrowings under the Revolver and/or lines of credit and/or to fund capital expenditures. The Prudential Shelf Agreement totaling $150.0 million was entered in October 2015 and we issued $70.0 million of 3.25% unsecured debt in April 2017. The Prudential Shelf Agreement was then amended in September 2018 to increase the borrowing capacity back to $150.0 million of which Prudential accepted our request to purchase our unsecured debt of $100.0 million at an interest rate of 3.98% on or before August 20, 2019. The NYL Shelf Agreement totaling $100.0 million was entered in March 2017 and we issued unsecured debt totaling $100.0 million during 2018. The NYL Shelf Agreement was amended in November 2018 to add incremental borrowing capacity of $50.0 million. As of December 31, 2018, we had not requested that MetLife purchase unsecured senior debt under the MetLife Shelf Agreement. The following table summarizes our shelf agreements borrowing information at December 31, 2018:

Shelf Agreement *(in thousands)*	Total Borrowing Capacity	Less: Amount of Debt Issued	Less: Unfunded Commitments	Remaining Borrowing Capacity
Prudential Shelf Agreement	$ 220,000	$ (70,000)	$ (100,000)	$ 50,000
MetLife Shelf Agreement	150,000	—	—	150,000
NYL Shelf Agreement	150,000	(100,000)	—	50,000
Total	$ 520,000	$ (170,000)	$ (100,000)	$ 250,000

The Shelf Agreements or Shelf Notes set forth certain business covenants to which we are subject when any note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

Short-Term Borrowings

Our outstanding short-term borrowings at December 31, 2018 and 2017 were $294.5 million and $251.0 million, respectively, at weighted average interest rates of 3.44 percent and 2.42 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures program. As of December 31, 2018, we had five unsecured bank credit facilities with four financial institutions totaling $220.0 million in available credit. In addition, we have $150.0 million of additional short-term debt capacity available under the Revolver. The terms of the Revolver are described in further detail below. None of the unsecured bank lines of credit requires compensating balances.

The $150.0 million Revolver is available through October 8, 2020 and is subject to the terms and conditions set forth in the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures. Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25 percent or less. Interest is payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We have the right, under certain circumstances, to extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each Lender.

Our outstanding short-term borrowings at December 31, 2018 and 2017 included $4.4 million and $10.3 million, respectively, of book overdrafts, which are not actual borrowings under the credit facilities but, if presented, would be funded through the credit facilities and, therefore, were included in the short-term borrowings.

Our outstanding borrowings under these unsecured short-term credit facilities at December 31, 2018 and 2017 were $290.1 million and $240.7 million, respectively. Short-term borrowings were as follows during 2018, 2017 and 2016:

(in thousands)	2018	2017	2016
Average borrowings during the year	$ 238,750	$ 183,561	$ 172,808
Weighted average interest rate for the year	2.93%	2.03%	1.43%
Maximum month-end borrowings	$ 290,103	$ 240,671	$ 201,311

As of December 31, 2018, we had issued $7.0 million in letters of credit to various counterparties under the Revolver. Although the letters of credit are not included in the outstanding short-term borrowings and we do not anticipate they will be drawn upon by the counterparties, the letters of credit reduce the available borrowings under the Revolver.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the years ended December 31, 2018, 2017 and 2016:

	For the Year Ended December 31,		
	2018	2017	2016
(in thousands)			
Net cash provided by (used in):			
Operating activities	$ 146,778	$ 110,089	$ 104,141
Investing activities	(286,264)	(186,895)	(170,037)
Financing activities	139,961	78,242	67,219
Net increase in cash and cash equivalents	475	1,436	1,323
Cash and cash equivalents—beginning of period	5,614	4,178	2,855
Cash and cash equivalents—end of period	$ 6,089	$ 5,614	$ 4,178

Cash Flows Provided by Operating Activities

Changes in our cash flows from operating activities are attributable primarily to changes in net income, adjusted for non-cash items such as depreciation and changes in deferred income taxes, and changes in working capital. Working capital requirements are determined by a variety of factors, including weather, the prices of natural gas, electricity and propane, the timing of customer collections, payments for purchases of natural gas, electricity and propane, and deferred fuel cost recoveries.

We normally generate a large portion of our annual net income and related increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas and propane delivered to customers during the peak heating season by our natural gas and propane operations and our natural gas supply, gathering and processing operation to customers during the peak heating season. In addition, our natural gas and propane inventories, which usually peak in the fall months, are largely drawn down in the heating season and provide a source of cash as the inventory is used to satisfy winter sales demand.

During 2018 and 2017, net cash provided by operating activities was $146.8 million and $110.1 million, respectively, resulting in an increase in cash flows of $36.7 million. Significant operating activities generating the cash flows change were as follows:

- Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities increased cash flows by $23.5 million, due primarily to the timing of the receipt of customer payments from increased revenue as well as the timing of payments to vendors.
- Net cash flows from changes in propane inventory, storage gas and other inventories increased by approximately $11.1 million due primarily to higher levels of our inventory during 2017.
- Changes in net prepaid expenses and other current assets, customer deposits and refunds decreased cash flows by $11.7 million due primarily to higher refund activity to customers associated with the impacts of the TCJA through the implementation of lower rates.
- Cash flows from changes in deferred income taxes resulted in an increase of $10.1 million due primarily to timing differences associated with depreciation from increased capital expenditures compared to the prior year, offset by $8.6 million in changes in income taxes payable as a result of the impacts of the TCJA.
- Changes in net regulatory assets and liabilities increased cash flows by $5.1 million, due primarily to the change in fuel costs collected through the various cost recovery mechanisms.

During 2017 and 2016, net cash provided by operating activities was $110.1 million and $104.1 million, respectively, resulting in an increase in cash flows of $6.0 million. Significant operating activities generating the cash flow change were as follows:

- Net income, adjusted for reconciling activities, decreased cash flows by $485,000. Key reconciling items included: the revaluation of deferred tax assets and liabilities of our unregulated businesses as a result of the implementation of the TCJA, which decreased our deferred tax expense by $14.3 million, higher non-cash adjustments for depreciation and amortization related to increased investing activities and realized losses on sales of assets.
- Net cash flows from changes in other inventories decreased by approximately $6.5 million, due primarily to purchases of additional pipes and other construction inventory as a result of the large expansion projects then underway.
- Changes in income taxes receivable increased cash flows by $5.6 million, due to higher tax refunds as a result of increased tax deductions associated with bonus depreciation.
- Changes in net regulatory assets and liabilities increased cash flows by $4.7 million, due primarily to the change in fuel costs collected through the various cost recovery mechanisms and GRIP.
- Changes in net accounts receivable, accrued revenue, accounts payable and accrued liabilities increased cash flows by $3.5 million, due primarily to higher revenues and the timing of customer payments and payments to vendors.
- Changes in net prepaid expenses and other current assets and customer deposits and refunds decreased cash flows by $2.2 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $286.3 million and $186.9 million during the year ended December 31, 2018 and 2017, respectively, resulting in a decrease in cash flows of $99.4 million. Key investing activities contributing to the cash flow change included:

- Cash paid for capital expenditures increased by $94.4 million due in part to the costs associated with restoring equipment and service to customers following Hurricane Michael in Florida.
- Net cash of $16.7 million was used to acquire operating assets of Ohl and Marlin CNG Services.

Net cash used in investing activities totaled $186.9 million and $170.0 million for 2017 and 2016, respectively, resulting in a decrease in cash flows of $16.9 million in 2017. Key investing activities contributing to the cash flow change included:

- Cash paid for capital expenditures increased by $5.4 million to $175.3 million for 2017.
- Net cash of $11.9 million was used to acquire assets in various transactions during 2017, including ARM, Chipola and Central Gas; there were no corresponding transactions in 2016.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities totaled $140.0 million for the year ended December 31, 2018, compared to net cash of $78.2 million provided by financing activities during the prior year resulted in an increase in cash flows of $61.7 million, primarily due to the following:

- Receipt of $154.8 million in net cash proceeds from the Revolver, the Term Note and the issuance of the NYL Shelf Notes (Series A) in May and November 2018, respectively, which increased cash flow by $85.0 million during the year

ended December 31, 2018, compared to the prior year. For the year ended December 31, 2017, we received $69.8 million in net proceeds from the issuance of the Prudential Shelf Notes;

- Increased cash flows from lower repayments of short-term borrowing of $10.1 million under our line of credit arrangements in 2018;
- Decreased cash flows of $7.7 million as a result of changes in cash overdrafts in 2018;
- Higher repayment of long-term debt and capital lease obligations of $34.4 million during the year ended December 31, 2018, compared to $12.1 million in the prior year; and
- Cash dividend payments of $22.0 million in 2018 compared to $19.9 million for 2017.

Net cash provided by financing activities totaled $78.2 million and $67.2 million for 2017 and 2016, respectively. The increase in net cash provided by financing activities in 2017 resulted primarily from the following:

- $69.8 million in net cash proceeds from the issuance of the Prudential Shelf Notes in 2017, offset by the payment of $3.0 million in scheduled long-term debt principal and capital lease obligations payments.
- Net cash flows decreased by $57.4 million due to the absence of proceeds related to the issuance of common stock during the third quarter of 2016.
- Net borrowing of $39.3 million for 2017, compared to net borrowing of $32.5 million for 2016, increased cash flows by $6.8 million. Change in cash overdrafts decreased cash flows by $2.2 million.
- Cash dividend payments of $19.9 million in 2017 compared to $17.5 million for 2016.

CONTRACTUAL OBLIGATIONS

We have the following contractual obligations and other commercial commitments as of December 31, 2018:

	Payments Due by Period				
Contractual Obligations	**2019**	**2020-2021**	**2022-2023**	**After 2023**	**Total**
(in thousands)					
Long-term debt [1]	$ 10,626	$ 59,200	$ 45,700	$ 211,700	$ 327,226
Operating leases [2]	2,349	3,759	3,331	5,398	14,837
Capital leases [2]	1,310	—	—	—	1,310
Purchase obligations [3]					
Transmission capacity	32,276	53,062	39,197	127,634	252,169
Storage capacity	1,720	978	355	—	3,053
Commodities	107,713	18,255	—	—	125,968
Electric supply	16,835	2,675	2,727	1,385	23,622
Unfunded benefits [4]	597	692	635	1,421	3,345
Funded benefits [5]	2,823	—	—	5,188	8,011
Total Contractual Obligations	**$ 176,249**	**$ 138,621**	**$ 91,945**	**$ 352,726**	**$ 759,541**

[1] This represents principal payments on long-term debt. See *Item 8, Financial Statements and Supplementary Data,* Note 13, *Long-Term Debt*, for additional information. The expected interest payments on long-term debt are $12.9 million, $21.6 million, $17.5 million and $49.8 million, respectively, for the periods indicated above. Expected interest payments for all periods total $101.8 million.

[2] See *Item 8, Financial Statements and Supplementary Data,* Note 15, *Lease Obligations*, for additional information.

[3] See *Item 8, Financial Statements and Supplementary Data,* Note 21, *Other Commitments and Contingencies*, for additional information.

[4] We have recorded long-term liabilities of $3.3 million at December 31, 2018 for unfunded post-employment and post-retirement benefit plans. The amounts specified in the table are based on expected payments to current retirees and assume a retirement age of 62 for currently active employees. There are many factors that would cause actual payments to differ from these amounts, including early retirement, future health care costs that differ from past experience and discount rates implicit in calculations. See *Item 8, Financial Statements and Supplementary Data,* Note 17, *Employee Benefit Plans*, for additional information on the plans.

[5] We have recorded long-term liabilities of $17.8 million at December 31, 2018 for two qualified, defined benefit pension plans. The assets funding these plans are in a separate trust and are not considered assets of ours or included in our balance sheets. The Contractual Obligations table above includes $1.3 million, reflecting the payments we expect to make to the trust funds in 2017. Additional contributions may be required in future years based on the actual return earned by the plan assets and other actuarial assumptions, such as the discount rate and long-term expected rate of return on plan assets. See *Item 8, Financial Statements and Supplementary Data,* Note 17, *Employee Benefit Plans*, for further information on the plans. Additionally, the Contractual Obligations table above includes deferred compensation obligations totaling $6.7 million, funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the consolidated balance sheets. We assume a retirement age of 65 for purposes of distribution from this account.

OFF-BALANCE SHEET ARRANGEMENTS

We have issued corporate guarantees to certain vendors of our subsidiaries that provide for the payment of propane and natural gas purchases in the event of the subsidiary's default. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at December 31, 2018 was $76.5 million, with the guarantees expiring on various dates throughout 2019.

We have issued letters of credit totaling $7.0 million related to the electric transmission services for FPU's northwest electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, and to our current and previous primary insurance carrier with expiration dates extending through December 2019. There were no draws on these letters of credit as of December 31, 2018. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future. Additional information is presented in *Item 8, Financial Statements and Supplementary Data,* Note 21, *Other Commitments and Contingencies* in the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

We prepare our financial statements in accordance with GAAP. Application of these accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingencies during the reporting period. We base our estimates on historical experience and on various assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Since a significant portion of our businesses are regulated and the accounting methods used by these businesses must comply with the requirements of the regulatory bodies, the choices available are limited by these regulatory requirements. In the normal course of business, estimated amounts are subsequently adjusted to actual results that may differ from the estimates.

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with ASC Topic 980, *Regulated Operations*, and consequently, the accounting principles applied by our regulated energy businesses differ in certain respects from those applied by the unregulated businesses. Amounts are deferred as regulatory assets and liabilities when there is a probable expectation that they will be recovered in future revenues or refunded to customers as a result of the regulatory process. This is more fully described in Item 8, *Financial Statements and Supplementary Data,* Note 2, *Summary of Significant Accounting Policies,* in the consolidated financial statements. If we were required to terminate the application of ASC Topic 980, we would be required to recognize all such deferred amounts as a charge or a credit to earnings, net of applicable income taxes. Such an adjustment could have a material effect on our results of operations.

Valuation of Environmental Liabilities and Related Regulatory Assets

As more fully described in Item 8, *Financial Statements and Supplementary Data,* Note 20, *Environmental Commitments and Contingencies*, in the consolidated financial statements, we are currently participating in the investigation, assessment or remediation of seven former MGP sites for which we have sought or will seek regulatory approval to recover through rates the estimated costs of remediation and related activities. Amounts have been recorded as environmental liabilities based on estimates of future costs to remediate these sites, which are provided by independent consultants.

Derivative Instruments

We use derivative and non-derivative instruments to manage the risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. We continually monitor the use of these instruments to ensure compliance with our risk management policies and account for them in accordance with GAAP, such that every derivative instrument is recorded as either an asset or a liability measured at its fair value. It also requires that changes in the derivatives' fair value are recognized in the current period earnings unless specific hedge accounting criteria are met. If these instruments do not meet the definition of derivatives or are considered "normal purchases and normal sales," they are accounted for on an accrual basis of accounting.

Additionally, GAAP also requires us to classify the derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the fair value of the assets and liabilities and their placement within the fair value hierarchy.

We determined that certain propane put options, call options, swap agreements and natural gas futures contracts met the specific hedge accounting criteria. We also determined that most of our contracts for the purchase or sale of natural gas, electricity and

propane either: (i) did not meet the definition of derivatives because they did not have a minimum purchase/sell requirement, or (ii) were considered "normal purchases and normal sales" because the contracts provided for the purchase or sale of natural gas, electricity or propane to be delivered in quantities that we expect to use or sell over a reasonable period of time in the normal course of business. Accordingly, these contracts were accounted for on an accrual basis of accounting.

Additional information about our derivative instruments is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 8, *Derivative Instruments,* in the Consolidated Financial Statements.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC of each state in which we operate. Customers' base rates may not be changed without formal approval by these PSCs. However, the PSCs authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. Eastern Shore's revenues are based on rates approved by the FERC. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to negotiated rates.

Peninsula Pipeline, our Florida intrastate pipeline subsidiary that is subject to regulation by the Florida PSC, has negotiated firm transportation service contracts with third-party customers and with certain affiliates.

For regulated deliveries of natural gas, propane and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class. A similar computation is made to accrue unbilled revenues for propane customers with meters, such as community gas system customers and natural gas marketing customers, whose billing cycles do not coincide with the accounting periods.

Our natural gas supply operation in Ohio recognizes revenues based on actual volumes of natural gas shipped, using contractual rates, which are based upon index prices that are published monthly.

Eight Flags records revenues based on the amount of electricity and steam generated and sold to its customers.

Each of our natural gas distribution operations in Delaware and Maryland, our bundled natural gas distribution service in Florida and our electric distribution operation in Florida has a fuel cost recovery mechanism. This mechanism provides a method of adjusting billing rates to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year.

We charge flexible rates to industrial interruptible customers on our natural gas distribution systems to compete with the price of alternative fuel that they can use. Neither we, nor any of our interruptible customers, are contractually obligated to deliver or receive natural gas on a firm service basis.

Allowance for Doubtful Accounts

An allowance for doubtful accounts is recorded against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect based upon our collections experience, the condition of the overall economy and our assessment of our customers' inability or reluctance to pay. If circumstances change, however, our estimate of the recoverability of accounts receivable may also change. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Goodwill and Other Intangible Assets

We test goodwill for impairment at least annually in December. The annual impairment testing for 2018 indicated no impairment of goodwill. Additional information is presented in Item 8, *Financial Statements and Supplementary Data,* Note 11, *Goodwill and Other Intangible Assets,* in the consolidated financial statements.

Other Assets Impairment Evaluations

We periodically evaluate whether events or circumstances have occurred which indicate that long-lived assets may not be recoverable. When events or circumstances indicate that an impairment is present, we record an impairment loss equal to the excess of the asset's carrying value over its fair value, if any.

Pension and Other Postretirement Benefits

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. The assumed discount rates and the expected returns on plan assets are the assumptions that generally have the most significant impact on the pension costs and liabilities. The assumed discount rates, the assumed health care cost trend rates and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. Additional information is presented in Item 8, *Financial Statements and Supplementary Data,* Note 17, *Employee Benefit Plans,* in the consolidated financial statements, including plan asset investment allocation, estimated future benefit payments, general descriptions of the plans, significant assumptions, the impact of certain changes in assumptions, and significant changes in estimates.

For 2018, actuarial assumptions include expected long-term rates of return on plan assets of 6.00 percent and 6.50 percent for Chesapeake Utilities' pension plan and FPU's pension plan, respectively, and discount rates of 3.50 percent and 3.75 percent for Chesapeake Utilities' and FPU's plans, respectively. The discount rate for each plan was determined by management considering high-quality corporate bond rates, such as the Prudential curve index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected lives of the plans and the availability of the lump-sum payment option. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately $20,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately $20,000.

Actual changes in the fair value of plan assets and the differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension benefit costs that we ultimately recognize. A 0.25 percent change in the rate of return could change our annual pension cost by approximately $128,000 and would not have an impact on the postretirement and Chesapeake SERP because these plans are not funded.

Tax-Related Contingency

We account for uncertainty in income taxes in the consolidated financial statements only if it is more likely than not that an uncertain tax position is sustainable based on its technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the consolidated financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

We account for contingencies associated with taxes other than income when the likelihood of a loss is both probable and quantifiable. In assessing the likelihood of a loss, we do not consider the existence of current inquiries, or the likelihood of future inquiries, by tax authorities as a factor. Our assessment is based solely on our application of the appropriate statutes and the likelihood of a loss, assuming the proper inquiries are made by tax authorities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

INTEREST RATE RISK

Long-term debt is subject to potential losses based on changes in interest rates. Additional information about our long-term debt is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 13, *Long-term Debt,* in the consolidated financial statements.

COMMODITY PRICE RISK

Regulated Energy Segment

We have entered into agreements with various wholesale suppliers to purchase natural gas and electricity for resale to our customers. Our regulated energy distribution businesses that sell natural gas or electricity to end-use customers have fuel cost recovery mechanisms authorized by the PSCs that allow us to recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers. Therefore, our regulated energy distribution operations have limited commodity price risk exposure.

Unregulated Energy Segment

Our propane operations are exposed to commodity price risk as a result of the competitive nature of retail pricing offered to our customers. In order to mitigate this risk, we utilize propane storage activities and forward contracts for supply.

We can store up to approximately 7.1 million gallons of propane (including leased storage and rail cars) during the winter season to serve our customers. Decreases in wholesale propane prices may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate this risk, we have implemented a Risk Management Policy that allows our propane operation to enter into fair value hedges, cash flows hedges or other economic hedges of our inventory.

Aspire Energy is exposed to commodity price risk, primarily during the winter season, to the extent we are not successful in balancing our natural gas purchases and sales and have to secure natural gas from alternative sources at higher spot prices. In order to mitigate this risk, we procure firm capacity that meets our estimated volume requirements and we continue to seek out new producers to fulfill our natural gas purchase requirements.

PESCO is a party to natural gas swap and futures contracts, which provide us the right to purchase natural gas at a fixed price at future dates. Upon expiration, the contracts can be settled financially without taking delivery of natural gas, or PESCO can procure natural gas and deliver it to its customers. PESCO is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids and natural gas deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts.

The following table reflects the changes in the fair market value of financial derivatives contracts related to natural gas and propane purchases and sales from December 31, 2017 to December 31, 2018:

(in thousands)	**Balance at December 31, 2017**	**Increase (Decrease) in Fair Market Value**	**Less Amounts Settled**	**Balance at December 31, 2018**
PESCO	$ (6,153)	$ 16,674	$ (10,705)	**$ (184)**
Sharp	1,192	(3,376)	663	**(1,521)**
Total	$ (4,961)	$ 13,298	$ (10,042)	**$ (1,705)**

There were no changes in the methods of valuations during the year ended December 31, 2018.

The following is a summary of fair market value of financial derivatives as of December 31, 2018, by method of valuation and by maturity for each fiscal year period.

(in thousands)	**2019**	**2020**	**2021**	**2022**	**Total Fair Value**
Price based on ICE[1] PESCO	$ (2,075)	$ 1,817	$ 72	$ 2	$ (184)
Price based on Mont Belvieu - Sharp	(1,229)	(250)	(42)	—	(1,521)
Total	$ (3,304)	$ 1,567	$ 30	$ 2	$ (1,705)

[1] Intercontinental Exchange (an electronic trading platform)

WHOLESALE CREDIT RISK

The Risk Management Committee reviews credit risks associated with counterparties to commodity derivative contracts prior to such contracts being approved.

Additional information about our derivative instruments is disclosed in Item 8, *Financial Statements and Supplementary Data,* Note 8, *Derivative Instruments,* in the Consolidated Financial Statements.

INFLATION

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we periodically seek rate increases from regulatory commissions for our regulated operations and closely monitor the returns of our unregulated energy business operations. To compensate for fluctuations in propane gas prices, we adjust propane sales prices to the extent allowed by the market.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Chesapeake Utilities Corporation

Opinions on the Consolidated Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation and Subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the years in the three-year period ended December 31, 2018, and the related notes and financial statement schedule listed in Item 15(a)2 (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework: (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework: (2013)* issued by COSO.

Basis for Opinion

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Als
projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate becaus
of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Baker Tilly Virchow Krause, LLP

We have served as the Company's auditor since 2007.

Philadelphia, Pennsylvania
February 26, 2019

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Income

(in thousands, except shares and per share data)	For the Year Ended December 31, 2018	2017	2016
Operating Revenues			
Regulated Energy	$ 345,281	$ 326,310	$ 305,689
Unregulated Energy	420,617	324,595	203,778
Other businesses and eliminations	(48,409)	(33,322)	(10,607)
Total operating revenues	717,489	617,583	498,860
Operating Expenses			
Regulated Energy cost of sales	121,828	118,769	109,609
Unregulated Energy and other cost of sales	288,913	219,145	128,434
Operations	138,441	125,994	115,684
Maintenance	14,387	12,701	12,391
Gain from a settlement	(130)	(130)	(130)
Depreciation and amortization	40,802	36,599	32,159
Other taxes	18,628	17,085	14,730
Total operating expenses	622,869	530,163	412,877
Operating Income	94,620	87,420	85,983
Other expense, net	(615)	(2,342)	(2,328)
Interest charges	16,431	12,645	10,639
Income Before Income Taxes	77,574	72,433	73,016
Income taxes	20,994	14,309	28,341
Net Income	$ 56,580	$ 58,124	$ 44,675
Weighted Average Common Shares Outstanding:			
Basic	16,369,616	16,336,789	15,570,539
Diluted	16,419,870	16,383,352	15,613,091
Earnings Per Share of Common Stock:			
Basic	$ 3.46	$ 3.56	$ 2.87
Diluted	$ 3.45	$ 3.55	$ 2.86
Cash Dividends Declared Per Share of Common Stock	$ 1.4350	$ 1.2800	$ 1.2025

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Comprehensive Income

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(in thousands)			
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Other Comprehensive Income (Loss), net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of $(22), $(31) and $(29), respectively	**(55)**	(46)	(48)
Net (loss)/gain, net of tax of $(49), $432, and $178, respectively	**(108)**	663	268
Cash Flow Hedges, net of tax:			
Unrealized (loss)/gain on commodity contract cash flow hedges, net of tax of $(555), $(8) and $496, respectively	**(1,371)**	(11)	742
Total Other Comprehensive Income (Loss)	**(1,534)**	606	962
Comprehensive Income	**$ 55,046**	$ 58,730	$ 45,637

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

	As of December 31,	
Assets	**2018**	**2017**
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	**$ 1,297,416**	$ 1,073,736
Unregulated Energy	**237,682**	210,682
Other businesses and eliminations	**34,585**	27,699
Total property, plant and equipment	**1,569,683**	1,312,117
Less: Accumulated depreciation and amortization	**(294,295)**	(270,599)
Plus: Construction work in progress	**108,584**	84,509
Net property, plant and equipment	**1,383,972**	1,126,027
Current Assets		
Cash and cash equivalents	**6,089**	5,614
Accounts receivable (less allowance for uncollectible accounts of $1,108 and $936, respectively)	**85,404**	77,223
Accrued revenue	**27,499**	22,279
Propane inventory, at average cost	**9,791**	8,324
Other inventory, at average cost	**7,127**	12,022
Regulatory assets	**4,796**	10,930
Storage gas prepayments	**6,603**	5,250
Income taxes receivable	**15,300**	14,778
Prepaid expenses	**10,079**	13,621
Derivative assets, at fair value	**13,165**	1,286
Other current assets	**5,684**	7,260
Total current assets	**191,537**	178,587
Deferred Charges and Other Assets		
Goodwill	**25,837**	19,604
Other intangible assets, net	**6,207**	4,686
Investments, at fair value	**6,711**	6,756
Regulatory assets	**72,422**	75,575
Receivables and other deferred charges	**6,985**	3,699
Total deferred charges and other assets	**118,162**	110,320
Total Assets	**$ 1,693,671**	$ 1,414,934

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Balance Sheets

Capitalization and Liabilities *(in thousands, except shares and per share data)*	As of December 31, 2018	2017
Capitalization		
Stockholders' equity		
Preferred stock, par value $0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	$ —	$ —
Common stock, par value $0.4867 per share (authorized 50,000,000 shares)	**7,971**	7,955
Additional paid-in capital	**255,651**	253,470
Retained earnings	**261,530**	229,141
Accumulated other comprehensive loss	**(6,713)**	(4,272)
Deferred compensation obligation	**3,854**	3,395
Treasury stock	**(3,854)**	(3,395)
Total stockholders' equity	**518,439**	486,294
Long-term debt, net of current maturities	**316,020**	197,395
Total capitalization	**834,459**	683,689
Current Liabilities		
Current portion of long-term debt	**11,935**	9,421
Short-term borrowing	**294,458**	250,969
Accounts payable	**129,804**	74,688
Customer deposits and refunds	**34,155**	34,751
Accrued interest	**2,317**	1,742
Dividends payable	**6,060**	5,312
Accrued compensation	**13,923**	13,112
Regulatory liabilities	**7,883**	6,485
Derivative liabilities, at fair value	**14,871**	6,247
Other accrued liabilities	**12,828**	10,273
Total current liabilities	**528,234**	413,000
Deferred Credits and Other Liabilities		
Deferred income taxes	**156,820**	135,850
Regulatory liabilities	**135,039**	140,978
Environmental liabilities	**7,638**	8,263
Other pension and benefit costs	**28,513**	29,699
Deferred investment tax credits and other liabilities	**2,968**	3,455
Total deferred credits and other liabilities	**330,978**	318,245
Environmental and other commitments and contingencies (Note 20 and 21)		
Total Capitalization and Liabilities	$ **1,693,671**	$ 1,414,934

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	For the Year Ended December 31,		
(in thousands)	2018	2017	2016
Operating Activities			
Net Income	$ 56,580	$ 58,124	$ 44,675
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	40,802	36,599	32,159
Depreciation and accretion included in operations expenses	8,535	8,122	7,334
Deferred income taxes, net	21,226	11,085	31,257
Realized loss on sale of assets/investments/commodity contracts	5,497	3,179	695
Unrealized loss (gain) on investments/commodity contracts	429	(1,001)	(385)
Employee benefits and compensation	856	1,577	1,887
Share-based compensation	2,813	2,490	2,367
Other, net	—	(750)	(79)
Changes in assets and liabilities:			
Accounts receivable and accrued revenue	(16,311)	(19,506)	(27,013)
Propane inventory, storage gas and other inventory	2,107	(9,036)	(2,531)
Regulatory assets/liabilities, net	2,250	(2,855)	(7,523)
Prepaid expenses and other current assets	(7,421)	(7,001)	(1,387)
Accounts payable and other accrued liabilities	35,907	15,596	19,599
Income taxes receivable (payable)	(522)	8,110	2,466
Customer deposits and refunds	(596)	5,513	2,065
Accrued compensation	708	2,488	358
Other assets and liabilities, net	(6,082)	(2,645)	(1,803)
Net cash provided by operating activities	146,778	110,089	104,141
Investing Activities			
Property, plant and equipment expenditures	(269,767)	(175,329)	(169,861)
Proceeds from sale of assets	782	708	174
Acquisitions, net of cash acquired	(16,654)	(11,945)	—
Environmental expenditures	(625)	(329)	(350)
Net cash used in investing activities	(286,264)	(186,895)	(170,037)
Financing Activities			
Common stock dividends	(22,043)	(19,928)	(17,482)
Issuance of stock for Dividend Reinvestment Plan	(706)	89	811
Proceeds from issuance of common stock, net of expenses	—	(10)	57,360
Tax withholding payments related to net settled stock compensation	(1,210)	(692)	(770)
Change in cash overdrafts due to outstanding checks	(5,943)	1,738	3,920
Net borrowing under line of credit agreements	49,432	39,338	32,526
Proceeds from issuance of long-term debt	154,819	69,807	—
Repayment of long-term debt and capital lease obligation	(34,388)	(12,100)	(9,146)
Net cash provided by financing activities	139,961	78,242	67,219
Net Increase in Cash and Cash Equivalents	475	1,436	1,323
Cash and Cash Equivalents — Beginning of Period	5,614	4,178	2,855
Cash and Cash Equivalents — End of Period	$ 6,089	$ 5,614	$ 4,178

Supplemental Cash Flow Disclosures (see Note 7)

The accompanying notes are an integral part of the financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Consolidated Statements of Stockholders' Equity

(in thousands, except shares and per share data)	Common Stock [1] Number of Shares[2]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2015	**15,270,659**	**$ 7,432**	**$ 190,311**	**$ 166,235**	**$ (5,840)**	**$ 1,883**	**$ (1,883)**	**$ 358,138**
Net Income	—	—	—	44,675	—	—	—	44,675
Other comprehensive loss	—	—	—	—	962	—	—	962
Dividends declared ($1.2025 per share)	—	—	—	(18,848)	—	—	—	(18,848)
Retirement savings plan and dividend reinvestment plan	36,253	17	2,225	—	—	—	—	2,242
Stock issuance [3]	960,488	467	56,893	—	—	—	—	57,360
Share-based compensation and tax benefit [4][5]	36,099	19	1,538	—	—	—	—	1,557
Treasury stock activities[2]	—	—	—	—	—	533	(533)	—
Balance at December 31, 2016	**16,303,499**	**7,935**	**250,967**	**192,062**	**(4,878)**	**2,416**	**(2,416)**	**446,086**
Net Income	—	—	—	58,124	—	—	—	58,124
Other comprehensive income	—	—	—	—	606	—	—	606
Dividends declared ($1.2800 per share)	—	—	—	(21,045)	—	—	—	(21,045)
Retirement savings plan and dividend reinvestment plan	10,771	5	730	—	—	—	—	735
Stock issuance [3]	—	—	(10)	—	—	—	—	(10)
Share-based compensation and tax benefit [4][5]	30,172	15	1,783	—	—	—	—	1,798
Treasury stock activities[2]	—	—	—	—	—	979	(979)	—
Balance at December 31, 2017	**16,344,442**	**7,955**	**253,470**	**229,141**	**(4,272)**	**3,395**	**(3,395)**	**486,294**
Net Income	—	—	—	56,580	—	—	—	56,580
Cumulative effect of the adoption of ASU 2014-09	—	—	—	(1,498)	—	—	—	(1,498)
Reclassification upon the adoption of ASU 2018-02	—	—	—	907	(907)	—	—	—
Other comprehensive income	—	—	—	—	(1,534)	—	—	(1,534)
Dividends declared ($1.4350 per share)	—	—	—	(23,600)	—	—	—	(23,600)
Dividend reinvestment plan	—	—	(3)	—	—	—	—	(3)
Share-based compensation and tax benefit [4][5]	34,103	16	2,184	—	—	—	—	2,200
Treasury stock activities[2]	—	—	—	—	—	459	(459)	—
Balance at December 31, 2018	**16,378,545**	**$ 7,971**	**$ 255,651**	**$ 261,530**	**$ (6,713)**	**$ 3,854**	**$ (3,854)**	**$ 518,439**

[1] 2,000,000 shares of preferred stock at $0.01 par value per share have been authorized. No shares have been issued or are outstanding; accordingly, no information has been included in the Statements of Stockholders' Equity. Shares of preferred stock may be issued from time to time, by authorization of our Board of Directors and at their discretion.

[2] Includes 97,053, 90,961 and 76,745 shares at December 31, 2018, 2017 and 2016, respectively, held in a Rabbi Trust related to our Non-Qualified Deferred Compensation Plan.

[3] On September 22, 2016, we completed a public offering of 960,488 shares of our common stock at a price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 million.

[4] Includes amounts for shares issued for directors' compensation.

[5] The shares issued under the SICP are net of shares withheld for employee taxes. For 2018, 2017 and 2016, we withheld 10,436, 10,269 and 12,031 shares, respectively, for taxes.

The accompanying notes are an integral part of the financial statements.

1. ORGANIZATION AND BASIS OF PRESENTATION

Chesapeake Utilities, incorporated in 1947 in Delaware, is a diversified energy company engaged in regulated and unregulated energy businesses.

Our regulated energy businesses consist of: (a) regulated natural gas distribution operations in central and southern Delaware, Maryland's eastern shore and Florida; (b) regulated natural gas transmission operations on the Delmarva Peninsula, in Pennsylvania and in Florida; and (c) regulated electric distribution operations serving customers in northeast and northwest Florida.

Our unregulated energy businesses primarily include: (a) propane operations in the Mid-Atlantic region and Florida; (b) our natural gas marketing operation providing natural gas supply directly to commercial and industrial customers in Florida, Delaware, Maryland, Pennsylvania, Ohio and other states; (c) our unregulated natural gas transmission/supply operation in central and eastern Ohio; (d) our CHP plant in Florida that generates electricity and steam; and (e) our newest subsidiary, based in Florida, that provides mobile compressed natural gas ("CNG") utility and pipeline solutions to commercial, industrial and other utility customers throughout the Southeast and Midwest portions of the country.

Our consolidated financial statements include the accounts of Chesapeake Utilities and its wholly-owned subsidiaries. We do not have any ownership interest in investments accounted for using the equity method or any interest in a variable interest entity. All intercompany accounts and transactions have been eliminated in consolidation. We have assessed and, if applicable, reported on subsequent events through the date of issuance of these consolidated financial statements.

We reclassified certain amounts in the consolidated statement of income for the years ended December 31, 2017 and 2016 to conform to the current year's presentation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates in measuring assets and liabilities and related revenues and expenses. These estimates involve judgments about various future economic factors that are difficult to predict and are beyond our control; therefore, actual results could differ from these estimates. As additional information becomes available, or actual amounts are determined, recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Property, Plant and Equipment

Property, plant and equipment are stated at original cost less accumulated depreciation or fair value, if impaired. Costs include direct labor, materials and third-party construction contractor costs, allowance for funds used during construction ("AFUDC"), and certain indirect costs related to equipment and employees engaged in construction. The costs of repairs and minor replacements are charged to expense as incurred, and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of property within the regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. Upon retirement or disposition of property owned by the unregulated businesses, the gain or loss, net of salvage value, is charged to income. A summary of property, plant and equipment by classification as of December 31, 2018 and 2017 is provided in the following table:

(in thousands)	As of December 31, 2018	2017
Property, plant and equipment		
Regulated Energy		
Natural gas distribution - Delmarva Peninsula and Florida	$ 657,630	$ 589,149
Natural gas transmission - Delmarva Peninsula, Pennsylvania and Florida	537,654	384,360
Electric distribution – Florida	102,133	100,227
Unregulated Energy		
Propane operations – Mid-Atlantic and Florida	123,632	108,177
Natural gas transmission – Ohio	70,225	66,037
Electricity and Steam generation – Florida	35,239	35,239
Mobile CNG utility and pipeline solutions	7,240	—
Other unregulated energy	1,346	1,229
Other	34,584	27,699
Total property, plant and equipment	1,569,683	1,312,117
Less: Accumulated depreciation and amortization	(294,295)	(270,599)
Plus: Construction work in progress	108,584	84,509
Net property, plant and equipment	$ 1,383,972	$ 1,126,027

Contributions or Advances in Aid of Construction

Customer contributions or advances in aid of construction reduce property, plant and equipment, unless the amounts are refundable to customers. Contributions or advances may be refundable to customers after a number of years based on the amount of revenues generated from the customers or the duration of the service provided to the customers. Refundable contributions or advances are recorded initially as liabilities. Non-refundable contributions reduce property, plant and equipment at the time of such determination. As of December 31, 2018, 2017 and 2016, the non-refundable contributions totaled $2.8 million, $2.1 million and $1.0 million, respectively.

AFUDC

Some of the additions to our regulated property, plant and equipment include AFUDC, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects. AFUDC is capitalized in the applicable rate base for ratemaking purposes when the completed projects are placed in service. During the year ended December 31, 2018, AFUDC totaled $1.9 million, which was reflected as a reduction of interest charges. During the years ended December 31, 2017 and 2016, AFUDC was not material.

Assets Used in Leases

Property, plant and equipment for the Florida natural gas transmission operation included $1.4 million of assets, at December 31, 2018 and 2017, consisting primarily of mains, measuring equipment and regulation station equipment used by Peninsula Pipeline to provide natural gas transmission service pursuant to a contract with a third party. This contract is accounted for as an operating lease due to the exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and generates $264,000 in annual revenue for a 20-year term. Accumulated depreciation for these assets totaled $720,000 and $652,000 at December 31, 2018 and 2017, respectively.

Capital Lease Assets

Property, plant and equipment include capital lease assets related to: (i) a lease arrangement entered into by our Delmarva Peninsula natural gas distribution operation associated with Sandpiper's capacity, supply and operating agreement and (ii) our Mid-Atlantic propane operation's lease arrangement for property in Anne Arundel County Maryland which it intends to purchase during the first quarter of 2019. Information regarding the impact of the capital leases in our financial statements is shown below. Additional information can be found in Note 21, *Other Commitments and Contingencies*.

(in thousands)	As of December 31, 2018	2017
Fair value of asset at lease inception	$ 7,816	$ 7,126
Less: Accumulated amortization	6,506	5,056
Capital lease asset	$ 1,310	$ 2,070

(in thousands)	For the years ended December 31, 2018	2017	2016
Amortization included in fuel cost recovery mechanism	$1,451	$1,401	$1,353

Jointly-owned Pipeline

Property, plant and equipment for our Florida natural gas transmission operation also included $6.7 million of assets, at December 31, 2018 and 2017, which consist of the 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida, jointly owned with Peoples Gas. The amount included in property, plant and equipment represents Peninsula Pipeline's 45-percent ownership of this pipeline. Peninsula Pipeline's share of direct expenses for the jointly-owned pipeline are included in the operating expenses of the income statement. Accumulated depreciation for this pipeline totaled $1.4 million and $1.3 million, at December 31, 2018 and 2017, respectively.

Asset Impairment Evaluations

We periodically evaluate whether events or circumstances have occurred, which indicate that other long-lived assets may not be fully recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the asset, compared to the carrying value of the asset. When such events or circumstances are present, we record an impairment loss equal to the excess of the asset's carrying value over its fair value, if any.

In May 2016, we received $650,000 in cash pursuant to a settlement agreement with a vendor related to implementation of a customer billing system which is reflected as "Gain from a settlement" in the accompanying consolidated statements of income. The retention of this amount is contingent upon engaging this vendor to provide agreed-upon services through May 2020.

Depreciation and Accretion Included in Operations Expenses

We compute depreciation expense for our regulated operations by applying composite, annual rates, as approved by the respective regulatory bodies. The following table shows the average depreciation rates used for regulated operations during the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
Natural gas distribution – Delmarva Peninsula	2.5%	2.5%	2.5%
Natural gas distribution – Florida	2.9%	2.9%	2.9%
Natural gas transmission – Delmarva Peninsula	2.7%	2.8%	2.7%
Natural gas transmission – Florida	2.3%	3.5%	3.9%
Electric distribution – Florida	3.4%	3.4%	3.5%

For our unregulated operations, we compute depreciation expense on a straight-line basis over the following estimated useful lives of the assets:

Asset Description	Useful Life
Propane distribution mains	10-37 years
Propane bulk plants and tanks	10-40 years
Propane equipment, meters and meter installations	5-33 years
Measuring and regulating station equipment	5-37 years
Natural gas pipelines	45 years
Natural gas right of ways	Perpetual
CHP plant	30 years
Natural gas processing equipment	20-25 years
Office furniture and equipment	3-10 years
Transportation equipment	4-20 years
Structures and improvements	5-45 years
Other	Various

We report certain depreciation and accretion in operations expense, rather than as a depreciation and amortization expense, in the accompanying consolidated statements of income in accordance with industry practice and regulatory requirements. Depreciation and accretion included in operations expense consists of the accretion of the costs of removal for future retirements of utility assets, vehicle depreciation, computer software and hardware depreciation, and other minor amounts of depreciation expense. For the years ended December 31, 2018, 2017 and 2016, we reported $8.5 million, $8.1 million and $7.3 million, respectively, of depreciation and accretion in operations expenses.

Regulated Operations

We account for our regulated operations in accordance with ASC Topic 980, *Regulated Operations,* which includes accounting principles for companies whose rates are determined by independent third-party regulators. When setting rates, regulators often make decisions, the economics of which require companies to defer costs or revenues in different periods than may be appropriate for unregulated enterprises. When this situation occurs, a regulated company defers the associated costs as regulatory assets on the balance sheet and records them as expense on the income statement as it collects revenues. Further, regulators can also impose liabilities upon a regulated company, for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future, as regulatory liabilities. If we were required to terminate the application of these regulatory provisions to our regulated operations, all such deferred amounts would be recognized in the statement of income at that time, which could have a material impact on our financial position, results of operations and cash flows.

We monitor our regulatory and competitive environments to determine whether the recovery of our regulatory assets continues to be probable. If we determined that recovery of these assets is no longer probable, we would write off the assets against earnings. We believe that the provisions of ASC Topic 980, *Regulated Operations,* continue to apply to our regulated operations and that the recovery of our regulatory assets is probable.

Revenue Recognition

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC in each state in which they operate. Eastern Shore's revenues are based on rates approved by the FERC. Customers' base rates may not be changed without formal approval by these commissions. The PSCs, however, have authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to FERC-approved maximum rates.

For regulated deliveries of natural gas and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class.

All of our regulated natural gas and electric distribution operations have fuel cost recovery mechanisms, except for two utilities that provide only unbundled delivery service (Chesapeake Utilities' Central Florida Gas division and FPU's Indiantown division). These mechanisms allow us to adjust billing rates, without further regulatory approvals, to reflect changes in the cost of purchased fuel. Differences between the cost of fuel purchased and delivered are deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year.

We charge flexible rates to our natural gas distribution industrial interruptible customers who can use alternative fuels. Interruptible service imposes no contractual obligation to deliver or receive natural gas on a firm service basis.

For the unregulated propane operation business, we record revenue in the period the products are delivered and/or services are rendered for bulk delivery customers without meters. For propane customers with meters and natural gas marketing customers whose billing cycles do not coincide with our accounting periods, we accrue unbilled revenue for product delivered but not yet billed and bill customers at the end of an accounting period, as we do in our regulated businesses.

Our Ohio natural gas transmission/supply operation recognizes revenues based on actual volumes of natural gas shipped using contractual rates based upon index prices that are published monthly.

Our natural gas marketing operation recognizes revenue based on the volume of natural gas delivered to its customers.

Eight Flags records revenues based on the amount of electricity and steam generated and sold to its customers.

We report revenue taxes, such as gross receipts taxes, franchise taxes, and sales taxes, on a net basis.

Cost of Sales

Cost of sales includes the direct costs attributable to the products sold or services provided to our customers. These costs include primarily the variable commodity cost of natural gas, electricity and propane, costs of pipeline capacity needed to transport and store natural gas, transmission costs for electricity, costs to gather and process natural gas, costs to transport propane to/from our storage facilities or our mobile CNG equipment to customer locations, and steam and electricity generation costs. Depreciation expense is not included in cost of sales.

Operations and Maintenance Expenses

Operations and maintenance expenses include operations and maintenance salaries and benefits, materials and supplies, usage of vehicles, tools and equipment, payments to contractors, utility plant maintenance, customer service, professional fees and other outside services, insurance expense, minor amounts of depreciation, accretion of removal costs for future retirements of utility assets and other administrative expenses.

Cash and Cash Equivalents

Our policy is to invest cash in excess of operating requirements in overnight income-producing accounts. Such amounts are stated at cost, which approximates fair value. Investments with an original maturity of three months or less when purchased are considered cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable consist primarily of amounts due for sales of natural gas, electricity and propane and transportation and distribution services to customers. An allowance for doubtful accounts is recorded against amounts due based upon our collections experiences and an assessment of our customers' inability or reluctance to pay. If circumstances change, our estimates of recoverable accounts receivable may also change. Circumstances which could affect such estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off when they are deemed to be uncollectible.

Inventories

We use the average cost method to value propane, materials and supplies, and other merchandise inventory. If market prices drop below cost, inventory balances that are subject to price risk are adjusted to their net realizable value. There was no lower-of-cost-or-net realizable value adjustment during 2018, 2017 or 2016.

Goodwill and Other Intangible Assets

Goodwill is not amortized but is tested for impairment at least annually, or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its implied fair value. The testing of goodwill for 2018, 2017 and 2016 indicated no goodwill impairment.

Other intangible assets are amortized on a straight-line basis over their estimated economic useful lives.

Other Deferred Charges

Other deferred charges include primarily issuance costs associated with short-term borrowings. These charges are amortized over the life of the related short-term debt borrowings.

Asset Removal Cost

As authorized by the appropriate regulatory body (state PSC or FERC), we accrue future asset removal costs associated with utility property, plant and equipment even if a legal obligation does not exist. Such accruals are provided for through depreciation expense and are recorded with corresponding credits to regulatory liabilities or assets. When we retire depreciable utility plant and equipment, we charge the associated original costs to accumulated depreciation and amortization, and any related removal costs incurred are charged to regulatory liabilities or assets. The difference between removal costs recognized in depreciation rates and the accretion and depreciation expense recognized for financial reporting purposes is a timing difference between recovery of these costs in rates and their recognition for financial reporting purposes. Accordingly, these differences are deferred as regulatory liabilities or assets. In the rate setting process, the regulatory liability or asset is excluded from the rate base upon which those utilities have the opportunity to earn their allowed rates of return. The costs associated with our asset retirement obligations are either currently being recovered in rates or are probable of recovery in future rates.

Pension and Other Postretirement Plans

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates, including the fair value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. We review annually the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities with the assistance of third-party actuarial firms. The assumed discount rates, expected returns on plan assets and the mortality assumption are the factors that generally have the most significant impact on our pension costs and liabilities. The assumed discount rates, health care cost trend rates and rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rates are utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When estimating our discount rates, we consider high-quality corporate bond rates, such as the Prudential curve index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected life of each of our plans and their respective payment options.

The expected long-term rates of return on assets are utilized in calculating the expected returns on the plan assets component of our annual pension plan costs. We estimate the expected returns on plan assets of each of our plans by evaluating expected bond returns, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rates of return on assets.

We estimate the health care cost trend rates used in determining our postretirement net expense based upon actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual reviews of participant census information as of the measurement date.

The mortality assumption used for our pension and postretirement plans reviewed periodically and is based on the actuarial table that best reflects of the expected mortality of the plan participants.

Income Taxes, Investment Tax Credit Adjustments and Tax-Related Contingency

Deferred tax assets and liabilities are recorded for the income tax effect of temporary differences between the financial statement basis and tax basis of assets and liabilities and are measured using the enacted income tax rates in effect in the years in which the differences are expected to reverse. Deferred tax assets are recorded net of any valuation allowance when it is more likely than not that such income tax benefits will be realized. Investment tax credits on utility property have been deferred and are allocated to income ratably over the lives of the subject property.

We account for uncertainty in income taxes in our consolidated financial statements only if it is more likely than not that an uncertain tax position is sustainable based on technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the consolidated financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

We account for contingencies associated with taxes other than income when the likelihood of a loss is both probable and estimable. In assessing the likelihood of a loss, we do not consider the existence of current inquiries, or the likelihood of future inquiries, by tax authorities as a factor. Our assessment is based solely on our application of the appropriate statutes and the likelihood of a loss, assuming the proper inquiries are made by tax authorities.

Financial Instruments

Our propane operations enter into derivative transactions, such as swaps, put options and call options in order to mitigate the impact of wholesale price fluctuations on inventory valuation and future purchase commitments. Our natural gas marketing

operation enters into natural gas futures and swap contracts to mitigate any price risk associated with the purchase and/or sale of natural gas to specific customers. These transactions may be designated as fair value hedges or cash flow hedges, if they meet all of the accounting requirements pursuant to ASC Topic 815, *Derivatives and Hedging,* and we elect to designate the instruments as hedges. If designated as a fair value hedge, the value of the hedging instrument, such as a swap, future, or put option, is recorded at fair value, with the effective portion of the gain or loss of the hedging instrument effectively reducing or increasing the value of the hedged item. If designated as a cash flow hedge, the value of the hedging instrument, such as a swap, call option or natural gas futures contract, is recorded at fair value with the effective portion of the gain or loss of the hedging instrument being recorded in comprehensive income. The ineffective portion of the gain or loss of a hedge is recorded in earnings. If the instrument is not designated as a fair value or cash flow hedge, or it does not meet the accounting requirements of a hedge under ASC Topic 815, Derivatives and Hedging, it is recorded at fair value with all gains or losses being recorded directly in earnings.

Our natural gas, electric and propane operations and natural gas marketing operations enter into agreements with suppliers to purchase natural gas, electricity, and propane for resale to our respective customers. Purchases under these contracts, as well as distribution and marketing operations sales agreements with counterparties or customers, either do not meet the definition of a derivative, or qualify for "normal purchases and sales" treatment under ASC Topic 815 *Derivatives and Hedging*, and are accounted for on an accrual basis.

Recently Adopted Accounting Standards

Revenue from Contracts with Customers (ASC 606) - On January 1, 2018, we adopted ASU 2014-09, *Revenue from Contracts with Customers,* and all the related amendments using the modified retrospective method. We recognized the cumulative effect of initially applying the new revenue standard to all of our contracts as an adjustment to the beginning balance of retained earnings. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The impact of adoption of the new revenue standard was immaterial to our net income.

This standard required entities to recognize revenue when control of the promised goods or services is transferred to customers at an amount that reflects the consideration that the entity expects to receive in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. See Note 5, *Revenue Recognition,* for additional information.

The following highlights the impact of the adoption of ASC 606 on our income statement for the year ended December 31, 2018 and consolidated balance sheet as of December 31, 2018:

	Year Ended December 31, 2018		
Income statement	As Reported	Without Adoption of ASC 606	Effect of Change Higher (Lower)
(in thousands)			
Regulated Energy operating revenues	$ 345,281	$ 346,289	$ (1,008)
Regulated Energy cost of sales	121,828	122,463	(635)
Depreciation and amortization	40,802	40,767	35
Income before income taxes	77,574	77,981	(407)
Income taxes	20,994	21,106	(112)
Net income	56,580	56,875	(295)

Balance sheet *(in thousands)*	As of December 31, 2018 As Reported	Without Adoption of ASC 606	Effect of Change Higher (Lower)
Assets			
Accrued revenue	$ 27,499	$ 29,461	$ (1,962)
Long-term receivables and other deferred charges	$ 6,985	$ 6,816	$ 169
Capitalization			
Retained earnings	$ 261,530	$ 263,323	$ (1,793)

The primary impact of the adoption of ASC 606 on our income statement was the delayed recognition of approximately $407,000 in operating income during the year ended December 31, 2018, to future years, and a cumulative adjustment that decreased retained earnings and other assets by $1.8 million at December 31, 2018, associated with a long-term firm transmission contract with an industrial customer.

Compensation-Retirement Benefits (ASC 715) - In March 2017, the FASB issued ASU 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost.* Under this guidance, employers are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit costs are required to be presented in the income statement separately from the service cost component and should not be included in operating expenses. We adopted ASU 2017-07 on January 1, 2018 and applied the changes in the other components of net benefit costs, retrospectively. As our plans have been frozen for some time, there is no service cost component. The components of net benefit costs have been reclassified to other expense. Aside from changes in presentation, implementation of this standard did not have a material impact on our financial position or results of operations.

Statement of Cash Flows (ASC 230) - In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments*, which clarifies how certain transactions are classified in the statement of cash flows. We adopted ASU 2016-15 on January 1, 2018. Implementation of this new standard did not have a material impact on our consolidated statement of cash flows.

Compensation - Stock Compensation (ASC 718) - In May 2017, the FASB issued ASU 2017-09, *Scope of Modification Accounting,* to clarify when to account for a change in the terms or conditions of a share-based payment award as a modification. Under this guidance, modification accounting is required only if the fair value, the vesting conditions or the award classification (equity or liability) change because of a change in the terms or conditions of the award. We adopted ASU 2017-09, prospectively, on January 1, 2018. Implementation of this new standard did not have a material impact on our financial position or results of operations.

Income Statement - Reporting Comprehensive Income (ASC 220) - In February 2018, the FASB issued ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA. We adopted ASU 2018-02 on January 1, 2018, and reclassified stranded tax effects from accumulated other comprehensive loss related to our employee benefit plans and commodity contract cash flows hedges. Implementation of this new standard did not have a material impact on our financial position and results of operations. See Note 16, *Stockholders' Equity,* for additional information.

Derivatives and Hedging (ASC 815) - In August 2017, the FASB issued ASU 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, to better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. ASU 2017-12 expands the risks that can be designated as hedged risks in cash flow hedges to include cash flow variability from contractually specified components of forecasted purchases or sales of non-financial assets. ASU 2017-12 requires the entire change in fair value of a hedging instrument that is included in the assessment of hedge effectiveness to be presented in the same income statement line that is used to present the earnings effects of the hedged item for fair value hedges and in other comprehensive income for cash flow hedges. ASU 2017-12 requires a tabular presentation of the income statement effect of fair value and cash flow hedges and eliminates the requirement to disclose the ineffective portion of the change in fair value of hedging instruments. We adopted ASU 2017-12, effective July 1, 2018, with no material impact on our financial statements. See Note 8, *Derivative Instruments,* for additional information with respect to the disclosures required by ASU 2017-12.

Compensation - Retirement Benefits - Defined Benefit Plans - General (ASC 715-20) - In August 2018, the FASB issued ASU 2018-14, *Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans*, which removes, clarifies and adds certain disclosure requirements in ASC 715-20 related to defined benefit pension and other postretirement plans. ASU

2018-14 will be effective for our annual and interim financial statements, on a retrospective basis, beginning January 1, 2021, although early adoption is permitted. We early adopted and updated our disclosures during the annual period ended December 31, 2018. Since the guidance impacted disclosures only, there was no impact on our financial position or results of operations.

Recent Accounting Standards Yet to be Adopted

Leases (ASC 842) - In February 2016, the FASB issued ASU 2016-02, *Leases,* which requires lessees to recognize leases on the balance sheet and disclose key information about leasing arrangements. The standard establishes a right of use ("ROU") model that requires a lessee to recognize a ROU asset and lease liability for all leases with a term greater than 12 months. The update also expands the required quantitative and qualitative disclosures surrounding leases. ASC 842 was subsequently amended by ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*; ASU No. 2018-10, *Codification Improvements to Topic 842, Leases*; and ASU No. 2018-11, *Targeted Improvements*. ASU 2016-02 will be effective for our annual and interim financial statements, beginning January 1, 2019, although early adoption is permitted. We expect to adopt ASU 2016-02 effective January 1, 2019, and use the modified retrospective transition approach to all existing leases.

The new standard permits companies to elect several practical expedients. We expect to elect: (1) the 'package of practical expedients,' pursuant to which we do not need to reassess our prior conclusions about lease identification, lease classification and initial direct costs and (2) the 'use-of-hindsight' practical expedient, which allows us to use hindsight in assessing impairment of our existing land easements. We also intend to aggregate all non-lease components with the respective lease components.

The most significant effect of ASC 842 will be recognition of ROU assets and lease liabilities on our balance sheet for our operating leases and providing significant new disclosures about our leasing activities. We currently expect that upon adoption, we will recognize lease liabilities ranging from $11.0 to $13.0 million, with corresponding ROU of the same amount based on the present value of the remaining minimum rental payments for existing operating leases.

Intangibles-Goodwill (ASC 350) - In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment*, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. ASU 2017-04 will be effective for our annual and interim financial statements beginning January 1, 2020, although early adoption is permitted. The amendments included in this ASU are to be applied prospectively. We believe that implementation of this new standard will not have a material impact on our financial position or results of operations.

Compensation - Stock Compensation (ASC 718) - In June 2018, the FASB issued ASU 2018-07, *Improvements to Nonemployee Share-Based Payment Accounting*, which expands the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees. ASU 2018-07 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. We believe that implementation of this new standard will not have a material impact on our financial position or results of operations.

Fair Value Measurement (ASC 820) - In August 2018, the FASB issued ASU 2018-13, *Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*, which removes, modifies and adds certain disclosure requirements on fair value measurements in ASC 820. ASU 2018-13 will be effective for our annual and interim financial statements beginning January 1, 2020. Since the changes only impact disclosures, there will be no financial impact.

3. EARNINGS PER SHARE

The following table presents the calculation of our basic and diluted earnings per share for the years ended December 31:

(in thousands, except shares and per share data)	For the Year Ended December 31, 2018	2017	2016
Calculation of Basic Earnings Per Share:			
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Weighted average shares outstanding	**16,369,616**	16,336,789	15,570,539
Basic Earnings Per Share	**$ 3.46**	$ 3.56	$ 2.87
Calculation of Diluted Earnings Per Share:			
Net Income	**$ 56,580**	$ 58,124	$ 44,675
Reconciliation of Denominator:			
Weighted average shares outstanding — Basic	**16,369,616**	16,336,789	15,570,539
Effect of dilutive securities — Share-based compensation	**50,254**	46,563	42,552
Adjusted denominator — Diluted	**16,419,870**	16,383,352	15,613,091
Diluted Earnings Per Share	**$ 3.45**	$ 3.55	$ 2.86

4. ACQUISITIONS

Acquisitions in 2018

Marlin Gas Services and Ohl Fuel Oil Acquisitions

In December 2018, Marlin Gas Services, LLC ("Marlin Gas Services"), our newly created subsidiary, acquired certain operating assets of Marlin Gas Transport, Inc. ("Marlin Gas Transport"), a supplier of mobile compressed natural gas utility and pipeline solutions. The acquisition will enable Chesapeake Utilities to offer solutions to address supply interruption scenarios and tailor other alternatives where pipeline supplies are not available or cannot meet customer requirements.

In December 2018, Sharp acquired certain propane operating assets and customers of R. F. Ohl Fuel Oil, Inc. ("Ohl"), which provided propane distribution service to approximately 2,500 residential and commercial customers in Pennsylvania.

We accounted for the purchases of the operating assets of Marlin Gas Transport and Ohl, which totaled approximately $18.4 million, as business combinations within our Unregulated Energy segment. Goodwill of $4.8 million, related to the Marlin Gas Transport acquisition, and $1.5 million, associated with the Ohl acquisition, were initially recorded at the close of these transactions. The amounts recorded in conjunction with these acquisitions are preliminary and subject to adjustment based on additional valuations performed during the measurement period. Due to the timing of these acquisitions, the revenue and net income from these acquisitions in 2018 were immaterial.

Acquisitions in 2017

ARM, Chipola and Central Gas Acquisitions

In August 2017, PESCO acquired certain natural gas marketing assets of ARM Energy Management, LLC ("ARM"). The acquired assets complemented PESCO's existing asset portfolio and expanded our regional footprint and retail demand in a market where we had existing pipeline capacity and wholesale liquidity. We accounted for the purchase of these assets as a business combination and initially recorded goodwill of $4.3 million within our Unregulated Energy segment. In connection with the acquisition, we initially recorded a contingent consideration liability of $2.5 million, based on a projection that the acquired business would achieve a gross margin target in 2018. During the second quarter of 2018, we identified certain known information as of the acquisition date that was not considered in our original analysis and would have resulted in no contingent consideration liability being initially recorded. Therefore, we reversed the originally-recorded contingent liability and reduced goodwill by $2.5 million. We similarly revised the consolidated balance sheet as of December 31, 2017. These revisions are considered immaterial to our consolidated financial statements. Based on actual gross margin results in 2018, we were not required to make additional payments under the contingent consideration provisions of the purchase agreement.

In August and December of 2017, Flo-gas acquired certain operating assets of Chipola Propane Gas Company ("Chipola") and Central Gas Company of Okeechobee, Incorporated ("Central Gas"), adding approximately 1,125 residential and commercial propane delivery service customers in Florida.

The acquisition accounting amounts recorded in conjunction with the above transactions are final. The revenue and net income from these acquisitions included in our consolidated statements of income were not material.

5. REVENUE RECOGNITION

We recognize revenue when our performance obligations under contracts with customers have been satisfied, which generally occurs when our businesses have delivered or transported natural gas, electricity or propane to customers. We exclude sales taxes and other similar taxes from the transaction price. Typically, our customers pay for the goods and/or services we provide in the month following the satisfaction of our performance obligation.

The following table displays our revenue by major source based on product and service type for the twelve months ended December 31, 2018:

(in thousands)	Regulated Energy	Unregulated Energy	Other and Eliminations	Total
Energy distribution				
Delaware natural gas division	$ 70,338	$ —	$ —	$ 70,338
Florida natural gas division	25,341	—	—	25,341
FPU electric distribution	79,803	—	—	79,803
FPU natural gas distribution	81,118	—	—	81,118
Maryland natural gas division	24,172	—	—	24,172
Sandpiper natural gas/propane operations	22,088	—	—	22,088
Total energy distribution	302,860	—	—	302,860
Energy transmission				
Aspire Energy	—	35,407	—	35,407
Eastern Shore	64,248	—	—	64,248
Peninsula Pipeline	11,927	—	—	11,927
Total energy transmission	76,175	35,407	—	111,582
Energy generation				
Eight Flags	—	17,302	—	17,302
Propane operations				
Mid-Atlantic propane operations	—	102,321	—	102,321
Florida propane operations	—	21,282	—	21,282
Total propane operations	—	123,603	—	123,603
Energy services				
Marlin Gas Services	—	121	—	121
PESCO - Natural Gas Marketing	—	258,713	—	258,713
	—	258,834	—	258,834
Other and eliminations				
Eliminations	(33,754)	(16,486)	(49,062)	(99,302)
Other	—	1,957	653	2,610
Total other and eliminations	(33,754)	(14,529)	(48,409)	(96,692)
Total operating revenues [1]	**$ 345,281**	**$ 420,617**	**$ (48,409)**	**$ 717,489**

[1] Includes other revenue (revenues from sources other than contracts with customers) of $236,000 and $334,000 for our Regulated and Unregulated Energy segments, respectively. The sources of other revenues include revenue from alternative revenue programs related to revenue normalization for Maryland division and Sandpiper and late fees.

Regulated Energy Segment

The businesses within our Regulated Energy segment are regulated utilities whose operations and customer contracts are subject to rates approved by the respective state PSC or the FERC.

Our energy distribution operations deliver natural gas or electricity to customers, and we bill the customers for both the delivery of natural gas or electricity and the related commodity, where applicable. In most jurisdictions, our customers are also required to purchase the commodity from us, although certain customers in some jurisdictions may purchase the commodity from a third-party retailer (in which case we provide delivery service only). We consider the delivery of natural gas or electricity and/or the related commodity sale as one performance obligation because the commodity and its delivery are highly interrelated with two-way dependency on one another. Our performance obligation is satisfied over time as natural gas or electricity is delivered and consumed by the customer. We recognize revenues based on monthly meter readings, which are based on the quantity of natural gas or electricity used and the approved rates. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period, to the extent that billing and delivery do not coincide.

Revenues for Eastern Shore are based on rates approved by the FERC. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to the FERC-approved maximum rates. Eastern Shore's services can be firm or interruptible. Firm services are offered on a guaranteed basis and are available at all times unless prevented by force majeure or other permitted curtailments. Interruptible customers receive service only when there is available capacity or supply. Our performance obligation is satisfied over time as we deliver natural gas to the customers' locations. We recognize revenues based on capacity used or reserved and the fixed monthly charge.

Peninsula Pipeline is engaged in natural gas intrastate transmission to third-party customers and certain affiliates in the State of Florida. Our performance obligation is satisfied over time as the natural gas is transported to customers. We recognize revenue based on rates approved by the Florida PSC and the capacity used or reserved. We accrue unbilled revenues for transportation services provided and not yet billed at the end of an accounting period.

Unregulated Energy Segment

Revenues generated from the Unregulated Energy segment are not subject to any federal, state, or local pricing regulations. Aspire Energy primarily sources gas from hundreds of conventional producers and performs gathering and processing functions to maintain the quality and reliability of its gas for its wholesale customers. Aspire Energy's performance obligation is satisfied over time as natural gas is delivered to its customers. Aspire Energy recognizes revenue based on the deliveries of natural gas at contractually agreed upon rates (which are based upon an established monthly index price and a monthly operating fee, as applicable). For natural gas customers, we accrue unbilled revenues for natural gas that has been delivered, but not yet billed, at the end of an accounting period, to the extent that billing and delivery do not coincide with the end of the accounting period.

Eight Flags' CHP plant, which is located on land leased from a customer, produces three sources of energy: electricity, steam and heated water. Rayonier purchases the steam (unfired and fired) and heated water, which are used in the customer's production facility. Our electric distribution operation purchases the electricity generated by the CHP plant for distribution to its customers. Eight Flags' performance obligation is satisfied over time as deliveries of heated water, steam and electricity occur. Eight Flags recognizes revenues over time based on the amount of heated water, steam and electricity generated and delivered to its customers.

For our propane operations, we recognize revenue based upon customer type and service offered. Generally, for propane bulk delivery customers (customers without meters) and wholesale sales, our performance obligation is satisfied when we deliver propane to the customers' locations (point-in-time basis). We recognize revenue from these customers based on the number of gallons delivered and the price per gallon at the point-in-time of delivery. For our propane delivery customers with meters, we satisfy our performance obligation over time when we deliver propane to customers. We recognize revenue over time based on the amount of propane consumed and the applicable price per unit. For propane delivery metered customers, we accrue unbilled revenues for propane that has been delivered, but not yet billed, at the end of an accounting period, to the extent that billing and delivery do not coincide with the end of the accounting period.

PESCO provides natural gas supply and asset management services to customers (including affiliates of Chesapeake Utilities) located primarily in Florida, the Delmarva Peninsula, and the Appalachian Basin. PESCO's performance obligation is satisfied over time as natural gas is delivered to its customers. PESCO recognizes revenue over time based on monthly customer meter readings. We accrue unbilled revenues for natural gas that has been delivered, but not yet billed, at the end of an accounting period.

Contract balances

The timing of revenue recognition, customer billings and cash collections results in trade receivables, unbilled receivables (contract assets), and customer advances (contract liabilities) in our consolidated balance sheets. The balances of our trade receivables, contract assets, and contract liabilities as of December 31, 2018 and 2017 were as follows:

(in thousands)	Trade Receivables	Contract Assets (Non-current)	Contract Liabilities (Current)
Balance at 12/31/2017	$ 74,962	$ 1,270	$ 407
Balance at 12/31/2018	**83,214**	**2,614**	**480**
Increase (decrease)	$ 8,252	$ 1,344	$ 73

Our trade receivables are included in accounts receivable in the consolidated balance sheets. Our non-current contract assets are included in receivables and other deferred charges in the consolidated balance sheet and relate to operations and maintenance costs incurred by Eight Flags that have not yet been recovered through rates for the sale of electricity to our electric distribution operation pursuant to a long-term service agreement.

At times, we receive advances or deposits from our customers before we satisfy our performance obligation, resulting in contract liabilities. At December 31, 2018 and 2017, we had a contract liability of $480,000 and $407,000, respectively, which was included in other accrued liabilities in the consolidated balance sheet, and which relates to non-refundable prepaid fixed fees for our Mid-Atlantic propane operation's retail offerings. Our performance obligation is satisfied over the term of the respective retail offering plan on a ratable basis. For the twelve months ended December 31, 2018, we recognized revenue of $697,000.

Remaining performance obligations

Our businesses have long-term fixed fee contracts with customers in which revenues are recognized as performance obligations are satisfied over the contract term. Revenue for these businesses for the remaining performance obligations at December 31, 2018 are expected to be recognized as follows:

(in thousands)	2019	2020	2021	2022	2023	2024 and thereafter
Eastern Shore and Peninsula Pipeline	$38,505	$36,768	$33,510	$26,566	$21,146	$ 212,620
Natural gas distribution operations	4,109	3,586	3,358	3,320	2,924	30,826
PESCO - Natural Gas Marketing	8,886	4,702	1,728	23	—	—
FPU electric distribution	297	297	297	109	—	—
Total revenue contracts with remaining performance obligations	$51,797	$45,353	$38,893	$30,018	$24,070	$ 243,446

Practical expedients

For our businesses with agreements that contain variable consideration, we use the invoice practical expedient method. We determined that the amounts invoiced to customers correspond directly with the value to our customers and our performance to date.

6. SEGMENT INFORMATION

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance.

Our operations are comprised of two reportable segments:

- *Regulated Energy.* Includes energy distribution and transmission services (natural gas distribution, natural gas transmission and electric distribution operations). All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.

- *Unregulated Energy.* Includes energy transmission, energy generation (the operations of our Eight Flags' CHP plant), propane operations, the new mobile CNG utility and pipeline solutions subsidiary, and other energy services (natural gas marketing and related services). These operations are unregulated as to their rates and services. Through March 2017, this segment also included the operations of Xeron, our propane and crude oil trading subsidiary that wound down its operations shortly after the first quarter of 2017. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

The remainder of our operations is presented as "Other businesses and eliminations," which consists of unregulated subsidiaries that own real estate leased to Chesapeake Utilities, as well as certain corporate costs not allocated to other operations.

The following table presents information about our reportable segments.

	For the Year Ended December 31,		
	2018	2017	2016
(in thousands)			
Operating Revenues, Unaffiliated Customers			
Regulated Energy	$ 332,749	$ 316,971	$ 302,402
Unregulated Energy	384,740	300,612	196,458
Total operating revenues, unaffiliated customers	$ 717,489	$ 617,583	$ 498,860
Intersegment Revenues [1]			
Regulated Energy	$ 12,532	$ 9,339	$ 3,287
Unregulated Energy	35,877	23,983	7,321
Other businesses	653	774	880
Total intersegment revenues	$ 49,062	$ 34,096	$ 11,488
Operating Income			
Regulated Energy	$ 79,215	$ 74,584	$ 71,515
Unregulated Energy	16,901	12,631	14,066
Other businesses and eliminations	(1,496)	205	402
Operating Income	94,620	87,420	85,983
Other expense	(615)	(2,342)	(2,328)
Interest charges	16,431	12,645	10,639
Income Before Income taxes	77,574	72,433	73,016
Income taxes	20,994	14,309	28,341
Net Income	$ 56,580	$ 58,124	$ 44,675
Depreciation and Amortization			
Regulated Energy	$ 31,876	$ 28,554	$ 25,677
Unregulated Energy	8,845	7,954	6,386
Other businesses and eliminations	81	91	96
Total depreciation and amortization	$ 40,802	$ 36,599	$ 32,159
Capital Expenditures			
Regulated Energy	$ 235,912	$ 159,011	$ 139,994
Unregulated Energy	38,700	26,190	23,984
Other businesses	8,364	5,902	5,398
Total capital expenditures	$ 282,976	$ 191,103	$ 169,376

[1] All significant intersegment revenues are billed at market rates and have been eliminated from consolidated revenues.

	As of December 31,	
	2018	2017
Identifiable Assets		
Regulated Energy	$ 1,345,805	$ 1,121,673
Unregulated Energy	306,045	259,041
Other businesses	41,821	34,220
Total identifiable assets	$ 1,693,671	$ 1,414,934

Our operations are entirely domestic.

7. SUPPLEMENTAL CASH FLOW DISCLOSURES

Cash paid for interest and income taxes during the years ended December 31, 2018, 2017 and 2016 were as follows:

	For the Year Ended December 31,		
	2018	2017	2016
(in thousands)			
Cash paid for interest	$ 16,741	$ 12,420	$ 10,315
Cash paid for income taxes, net of refunds	$ 477	$ (4,114)	$ (5,308)

Non-cash investing and financing activities during the years ended December 31, 2018, 2017, and 2016 were as follows:

	For the Year Ended December 31,		
	2018	2017	2016
(in thousands)			
Capital property and equipment acquired on account, but not paid for as of December 31	$ 39,402	$ 15,457	$ 9,791
Common stock issued for the Retirement Savings Plan	$ —	$ —	$ 777
Common stock issued under the SICP	$ 2,006	$ 1,127	$ 1,027
Capital lease obligation	$ 1,310	$ 2,070	$ 3,471

8. DERIVATIVE INSTRUMENTS

We use derivative and non-derivative contracts to manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to our customers. Aspire Energy has entered into contracts with producers to secure natural gas to meet its obligations. Purchases under these contracts typically either do not meet the definition of derivatives or are considered "normal purchases and normal sales" and are accounted for on an accrual basis. Both our propane operations and our natural gas marketing operations may also enter into fair value hedges of their inventory or cash flow hedges of their future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of December 31, 2018 and 2017 our natural gas and electric distribution operations did not have any outstanding derivative contracts.

We adopted ASU 2017-12 as of July 1, 2018. See Note 1, *Summary of Significant Accounting Policies,* under the heading "recently adopted accounting standards" for additional details.

Volume of Derivative Activity

As of December 31, 2018, the volume of our open commodity derivative contracts were as follows:

Business unit	Commodity	Quantity hedged (in millions)	Designation	Longest Expiration date of hedge
PESCO/natural gas marketing	Natural gas (Dts)	14.4	Cash flows hedges	March 2022
PESCO/natural gas marketing	Natural gas (Dts)	3.8	Not designated	December 2020
Sharp/propane operations	Propane (gallons)	9.7	Cash flows hedges	June 2021
Sharp/propane operations	Propane (gallons)	0.3	Fair value hedges	March 2019

PESCO entered into natural gas futures contracts associated with the purchase and sale of natural gas to specific customers. We designated and accounted for them as cash flow hedges. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss) and later recognized in the statement of income in the same period and in the same line item as the hedged transaction. We expect to reclassify approximately $1.5 million from accumulated other comprehensive loss to earnings during the next 12-month period ending December 31, 2019.

Sharp entered into futures and swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with the propane volumes expected to be purchased during the heating season. Under the futures and swap agreements, Sharp will receive the difference between (i) the index prices (Mont Belvieu prices in August 2018 through June 2021) and (ii) the per gallon propane swap prices, to the extent the index prices exceed the contracted prices. If the index prices are lower than the swap prices, Sharp will pay the difference. We designated and accounted for propane swaps as cash flows hedges. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss) and later recognized in the statement of income in the same period and in the same line item as the hedged transaction. We expect to reclassify approximately $1.2 million from accumulated other comprehensive income to earnings during the next 12-month period ending December 31, 2019.

Balance sheet offsetting

PESCO has entered into master netting agreements with counterparties that enable it to net the counterparties' outstanding accounts receivable and payable, which are presented on a net basis in the consolidated balance sheets. The following table summarizes the accounts receivable and payables on a gross and net basis at December 31, 2018 and 2017:

	At December 31, 2018		
(in thousands)	Gross amounts	Amounts offset	Net amounts
Accounts receivable	**$ 12,368**	**$ 3,834**	**$ 8,534**
Accounts payable	**$ 24,741**	**$ 3,834**	**$ 20,907**

	At December 31, 2017		
(in thousands)	Gross amounts	Amounts offset	Net amounts
Accounts receivable	$ 8,283	$ 2,391	$ 5,892
Accounts payable	$ 16,643	$ 2,391	$ 14,252

Broker Margin

Futures exchanges have contract specific margin requirements that require the posting of cash or cash equivalents relating to traded contracts. Margin requirements consist of initial margin that is posted upon the initiation of a position, maintenance margin that is usually expressed as a percent of initial margin, and variation margin that fluctuates based on the daily MTM relative to maintenance margin requirements. We maintain separate broker margin accounts for Sharp and PESCO. At December 31, 2018 and 2017, Sharp's account had a zero balance. The balances related to PESCO are as follows:

(in thousands)	**Balance Sheet Location**	**December 31, 2018**	**December 31, 2017**
PESCO	Other Current Assets	**$ 2,810**	$ 6,300

Financial Statements Presentation

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency. Fair values of the derivative contracts recorded in the consolidated balance sheets as of December 31, 2018 and 2017 are as follows:

		Derivative Assets	
		Fair Value As Of	
(in thousands)	Balance Sheet Location	December 31, 2018	December 31, 2017
Derivatives not designated as hedging instruments			
Propane swap agreements	Derivative assets, at fair value	$ —	$ 13
Natural gas futures contracts	Derivative assets, at fair value	4,024	—
Derivatives designated as fair value hedges			
Propane put options	Derivative assets, at fair value	71	—
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative assets, at fair value	9,059	92
Propane swap agreements	Derivative assets, at fair value	11	1,181
Total Derivative Assets		$ 13,165	$ 1,286

		Derivative Liabilities	
		Fair Value As Of	
(in thousands)	Balance Sheet Location	December 31, 2018	December 31, 2017
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Derivative liabilities, at fair value	$ 4,562	$ 5,776
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative liabilities, at fair value	8,705	—
Natural gas swap contracts	Derivative liabilities, at fair value	—	469
Propane swap agreements	Derivative liabilities, at fair value	1,604	2
Total Derivative Liabilities		$ 14,871	$ 6,247

The effects of gains and losses from derivative instruments are as follows:

		Amount of Gain (Loss) on Derivatives:		
		For the Year Ended December 31,		
(in thousands)	Location of Gain (Loss) on Derivatives	2018	2017	2016
Derivatives not designated as hedging instruments				
Realized gain (loss) on forward contracts and options [1]	Revenue	$ —	$ 112	$ (546)
Natural gas futures contracts	Cost of sales	(3,189)	(3,633)	(541)
Propane swap agreements	Cost of sales	(13)	8	7
Natural gas swap contracts	Cost of sales	—	1	—
Derivatives designated as fair value hedges				
Put/Call option	Cost of sales	—	(9)	49
Natural gas futures contracts	Natural gas inventory	—	—	(233)
Derivatives designated as cash flow hedges				
Propane swap agreements	Cost of sales	(647)	1,607	(364)
Propane swap agreements	Other comprehensive income (loss)	(2,773)	487	1,016
Natural gas futures contracts	Cost of sales	(2,010)	(456)	345
Natural gas swap contracts	Cost of sales	197	(822)	—
Natural gas futures contracts	Other comprehensive income (loss)	532	(1,476)	222
Natural gas swap contracts	Other comprehensive income	200	986	—
Total		$ (7,703)	$ (3,195)	$ (45)

[1] All of the realized and unrealized gain (loss) on forward contracts represents the effect of trading activities on our consolidated statements of income.

As of December 31, 2018, the following amounts were recorded in the consolidated balance sheets related to fair value hedges:

(in thousands)	Carrying Amount of Hedged Item		Cumulative Adjustment Included in Carrying Amount of Hedged Item	
Balance Sheet Location of Hedged Items	**At December 31, 2018**	**At December 31, 2017**	**At December 31, 2018**	**At December 31, 2017**
Inventory	$ 212	$ —	$ —	$ —

9. Fair Value of Financial Instruments

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The three levels of the fair value hierarchy are the following:

Fair Value Hierarchy	Description of Fair Value Level	Fair Value Technique Utilized
Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities	*Investments - equity securities* - The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities. *Investments - mutual funds and other* - The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability	*Derivative assets and liabilities* - The fair values of forward contracts are measured using market transactions in either the listed or over-the-counter markets. The fair value of the propane put/call options, swap agreements and natural gas futures contracts are measured using market transactions for similar assets and liabilities in either the listed or over-the-counter markets.
Level 3	Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity)	*Investments - guaranteed income fund* - The fair values of these investments are recorded at the contract value, which approximates their fair value.

Financial Assets and Liabilities Measured at Fair Value

The following tables summarize our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy as of December 31, 2018 and 2017, respectively:

		Fair Value Measurements Using:		
As of December 31, 2018 *(in thousands)*	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments—equity securities	$ 22	$ 22	$ —	$ —
Investments—guaranteed income fund	686	—	—	686
Investments—mutual funds and other	6,003	6,003	—	—
Total investments	6,711	6,025	—	686
Derivative assets	13,165	—	13,165	—
Total assets	$ 19,876	$ 6,025	$ 13,165	$ 686
Liabilities:				
Derivative liabilities	$ 14,871	$ —	$ 14,871	$ —

As of December 31, 2017 (in thousands)	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments—equity securities	$ 22	$ 22	$ —	$ —
Investments—guaranteed income fund	648	—	—	648
Investments—mutual funds and other	6,086	6,086	—	—
Total investments	6,756	6,108	—	648
Derivative assets	1,286	—	1,286	—
Total assets	$ 8,042	$ 6,108	$ 1,286	$ 648
Liabilities:				
Derivative liabilities	$ 6,247	$ —	$ 6,247	$ —

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2018 and 2017:

(in thousands)	For the Year Ended December 31, 2018	2017
Beginning Balance	$ 648	$ 561
Purchases and adjustments	68	79
Transfers/disbursements	(41)	(53)
Investment income	11	61
Ending Balance	$ 686	$ 648

Investment income from the Level 3 investments is reflected in other expense, net in the consolidated statements of income.

At December 31, 2018 and 2017, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).

At December 31, 2018, long-term debt, which includes the current maturities but excludes capital lease obligations, had a carrying value of $327.2 million, compared to the estimated fair value of $323.8 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, adjusted for duration, optionality and risk profile. At December 31, 2017, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of $205.2 million, compared to a fair value of $215.4 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

See Note 17, *Employee Benefit Plans,* for fair value measurement information related to our pension plan assets.

10. INVESTMENTS

The investment balances at December 31, 2018 and 2017, consisted of the following:

	As of December 31,	
(in thousands)	2018	2017
Rabbi trust (associated with the Non-Qualified Deferred Compensation Plan)	$ 6,689	$ 6,734
Investments in equity securities	22	22
Total	$ 6,711	$ 6,756

We classify these investments as trading securities and report them at their fair value. For the year ended December 31, 2018, we recorded net unrealized losses of $428,000 and for the years ended December 31, 2017 and 2016, we recorded net unrealized gains of $1.0 million and $379,000, respectively, in other income (expense) in the consolidated statements of income related to these investments. For the investment in the Rabbi Trust, we also have recorded an associated liability, which is included in other pension and benefit costs in the consolidated balance sheets and is adjusted each period for the gains and losses incurred by the investments in the Rabbi Trust.

11. GOODWILL AND OTHER INTANGIBLE ASSETS

The carrying value of goodwill as of December 31, 2018 and 2017 was as follows:

	As of December 31,	
(in thousands)	2018	2017
Goodwill		
Regulated Energy		
Florida Natural Gas Distribution[1]	$ 3,353	$ 3,353
Unregulated Energy		
Mid-Atlantic Propane Operations	2,147	674
Florida Propane Operations	1,188	1,188
Aspire Energy	10,119	10,119
Marlin Gas Services	4,760	—
Natural Gas Marketing - PESCO	4,270	4,270
Total Goodwill	$ 25,837	$ 19,604

[1] Florida natural gas distribution includes Chesapeake Utilities' Central Florida Gas division, FPU and FPU's Indiantown and Fort Meade divisions.

The annual impairment testing for 2018 and 2017 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2018 and 2017 are as follows:

	As of December 31,			
	2018		2017	
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Customer lists	$ 7,757	$ 3,664	$ 7,393	$ 2,880
Non-Compete agreements	2,245	202	270	175
Other	270	199	270	192
Total	$ 10,272	$ 4,065	$ 7,933	$ 3,247

The customer lists, non-compete agreements and other intangibles acquired in the purchases of the operating assets of several companies are being amortized over five to 41 years.

For the years ended December 31, 2018, 2017 and 2016, amortization expense of intangible assets was $818,000, $537,000, and $380,000, respectively. Amortization expense of intangible assets is expected to be $1.1 million for each of the years 2019, 2020 and 2021, $820,000 for 2022 and $813,000 for 2023.

12. INCOME TAXES

We file a consolidated federal income tax return. Income tax expense allocated to our subsidiaries is based upon their respective taxable incomes and tax credits. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. Our state returns for tax years after 2014 are subject to examination. At December 31, 2018, the 2015 and 2016 federal income tax returns are under examination, and no report has been issued at this time.

We had no net operating loss for federal income tax purposes as of December 31, 2018 and 2017. For state income tax purposes, we had net operating losses in various states of $60.1 million and $34.2 million as of December 31, 2018 and 2017, respectively, almost all of which will expire in 2037. We have recorded deferred tax assets of $2.0 million and $1.6 million related to state net operating loss carry-forwards at December 31, 2018 and 2017, respectively, but we have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will be fully utilized.

Federal Tax Reform

On December 22, 2017, President Trump signed into law the TCJA. Substantially all of the provisions of the TCJA are effective for taxable years beginning on or after January 1, 2018. The provisions significantly impacting us include the reduction of the corporate federal income tax rate from 35 percent to 21 percent. Our federal income tax expense for periods beginning on January 1, 2018 are based on the new federal corporate income tax rate. The TCJA included changes to the Internal Revenue Code, which materially impacted our 2017 financial statements. ASC 740, *Income Taxes,* requires recognition of the effects of changes in tax laws in the period in which the law is enacted. ASC 740 requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. We have completed the assessment of the impact as it relates to accounting for certain effects of the TCJA. At the date of enactment in 2017, we re-measured deferred income taxes based upon the new corporate tax rate. See Note 19, *Rates and Other Regulatory Activities,* for further discussion of the TCJA's impact on our regulated businesses.

In 2018, we elected early adoption of ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* Accordingly, we reclassified stranded tax effects resulting from the TCJA from accumulated other comprehensive loss to retained earnings, related to our employee benefit plans and commodity contracts cash flow hedges.

The following tables provide: (a) the components of income tax expense in 2018, 2017, and 2016; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2018, 2017, and 2016; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2018 and 2017.

	For the Year Ended December 31,		
	2018	2017	2016
(in thousands)			
Current Income Tax Expense			
Federal	$ (845)	$ 2,803	$ (4,898)
State	660	492	2,053
Other	(47)	(71)	(71)
Total current income tax expense	(232)	3,224	(2,916)
Deferred Income Tax Expense [1]			
Property, plant and equipment	19,164	8,314	31,062
Deferred gas costs	(1,435)	2,002	1,163
Pensions and other employee benefits	463	180	237
FPU merger-related premium cost and deferred gain	(528)	(1,148)	(572)
Net operating loss carryforwards	(331)	193	(9)
Other	3,893	1,544	(624)
Total deferred income tax expense	21,226	11,085	31,257
Total Income Tax Expense	$ 20,994	$ 14,309	$ 28,341

[1] Includes $3.5 million, $873,000 and $2.1 million of deferred state income taxes for the years 2018, 2017 and 2016, respectively.

(in thousands)	For the Year Ended December 31, 2018	2017	2016
Reconciliation of Effective Income Tax Rates			
Federal income tax expense [1]	$ 16,291	$ 25,351	$ 22,759
State income taxes, net of federal benefit	4,088	1,894	3,422
ESOP dividend deduction	(158)	(257)	(264)
Revaluation of deferred tax assets and liabilities	—	(14,299)	—
Other	773	1,620	2,424
Total Income Tax Expense	$ 20,994	$ 14,309	$ 28,341
Effective Income Tax Rate [2]	27.06%	19.75%	38.81%

[1] Federal income taxes were calculated at 21 percent for 2018 and 35 percent for 2017 and 2016.
[2] Effective tax rate 2017 includes the impact of the revaluation of deferred tax assets and liabilities for our unregulated businesses due to implementation of the TCJA.

(in thousands)	As of December 31, 2018	2017
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	$ 153,423	$ 133,581
Acquisition adjustment	8,896	9,323
Loss on reacquired debt	32	153
Deferred gas costs	1,139	2,574
Natural gas conversion costs	3,987	2,760
Other	2,641	2,662
Total deferred income tax liabilities	170,118	151,053
Deferred income tax assets:		
Pension and other employee benefits	3,711	4,698
Environmental costs	1,710	1,744
Net operating loss carryforwards	2,010	1,625
Self-insurance	151	164
Storm reserve liability	—	717
Other	5,716	6,255
Total deferred income tax assets	13,298	15,203
Deferred Income Taxes Per Consolidated Balance Sheets	$ 156,820	$ 135,850

Notes to the Consolidated Financial Statements

13. LONG-TERM DEBT

Our outstanding long-term debt is shown below:

	As of December 31,	
(in thousands)	2018	2017
FPU secured first mortgage bonds:		
9.08% bond, due June 1, 2022	$ 7,986	$ 7,982
Uncollateralized Senior Notes:		
5.50% note, due October 12, 2020	4,000	6,000
5.93% note, due October 31, 2023	15,000	18,000
5.68% note, due June 30, 2026	23,200	26,100
6.43% note, due May 2, 2028	7,000	7,000
3.73% note, due December 16, 2028	20,000	20,000
3.88% note, due May 15, 2029	50,000	50,000
3.25% note, due April 30, 2032	70,000	70,000
3.48% note, due May 31, 2038	50,000	—
3.58% note, due November 30, 2038	50,000	—
Term Note due January 21, 2020 [1]	30,000	—
Promissory notes	26	97
Capital lease obligations	1,310	2,070
Less: debt issuance costs	(567)	(433)
Total long-term debt	327,955	206,816
Less: current maturities	(11,935)	(9,421)
Total long-term debt, net of current maturities	$ 316,020	$ 197,395

[1] In December of 2018 we issued a $30.0 million unsecured Term Note through PNC Bank N.A. The maturity date of the Term Note is January 21, 2020. The Term Note bears interest at a rate equal to the one month LIBOR rate plus 75 basis points. The interest rate at December 31, 2018 was 3.23%

Annual maturities

Annual maturities and principal repayments of long-term debt, excluding the capital lease obligation, are as follows:

Year	2019	2020	2021	2022	2023	Thereafter	Total
(in thousands)							
Payments	$ 10,626	$ 45,600	$ 13,600	$ 25,100	$ 20,600	$ 211,700	$ 327,226

See Note 15, *Lease Obligations,* for future payments related to the capital lease obligation.

Shelf Agreements

We have entered into Shelf Agreements with Prudential, MetLife and NYL who are under no obligation to purchase any unsecured debt.

The Prudential Shelf Agreement totaling $150.0 million was entered in October 2015 and we issued $70.0 million of 3.25 percent unsecured debt in April 2017. The Prudential Shelf Agreement was amended in September 2018 to increase the borrowing capacity to $150.0 million after which Prudential accepted our request to purchase our unsecured debt of $100.0 million at an interest rate of 3.98 percent on or before August 20, 2019. The NYL Shelf Agreement totaling $100.0 million was entered in March 2017 and we issued unsecured debt totaling $100.0 million during 2018. The NYL Shelf Agreement was amended in November 2018 to provide additional borrowing capacity of $50.0 million. As of December 31, 2018, we had not requested that MetLife purchase unsecured senior debt under the MetLife Shelf Agreement.

The following table summarizes our shelf agreements borrowing information at December 31, 2018:

(in thousands)	Total Borrowing Capacity	Less Amount of Debt Issued	Less Unfunded Commitments	Remaining Borrowing Capacity
Shelf Agreement				
Prudential Shelf Agreement	$ 220,000	$ (70,000)	$ (100,000)	$ 50,000
MetLife Shelf Agreement	150,000	—	—	150,000
NYL Shelf Agreement	150,000	(100,000)	—	50,000
Total	$ 520,000	$ (170,000)	$ (100,000)	$ 250,000

The Prudential Shelf Agreement and the NYL Shelf Agreement set forth certain business covenants to which we are subject when any note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

Secured First Mortgage Bonds

We guaranteed FPU's first mortgage bonds, which are secured by a lien covering all of FPU's property. FPU's first mortgage bonds contain a restriction that limits the payment of dividends by FPU to an amount less than the sum of $2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2018, FPU's cumulative net income base was $155.8 million, offset by restricted payments of $37.6 million, leaving $118.2 million of available dividend capacity.

The dividend restrictions in FPU's first mortgage bonds resulted in approximately $42.2 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2018. This represents approximately 8.1 percent of our consolidated net assets. Other than the dividend restrictions associated with FPU's first mortgage bonds, there are no legal, contractual or regulatory restrictions on the net assets of our subsidiaries.

Uncollateralized Senior Notes

All of our uncollateralized Senior Notes require periodic principal and interest payments as specified in each note. They also contain various restrictions. The most stringent restrictions state that we must maintain equity of at least 40.0 percent of total capitalization, and the fixed charge coverage ratio must be at least 1.2 times. The most recent Senior Notes issued in December 2013 also contain a restriction that we must maintain an aggregate net book value in our regulated business assets of at least 50.0 percent of our consolidated total assets. Failure to comply with those covenants could result in accelerated due dates and/or termination of the Senior Note agreements.

Certain uncollateralized Senior Notes contain a "restricted payments" covenant as defined in the respective note agreements. The most restrictive covenants of this type are included within the 5.93 percent Senior Note, due October 31, 2023. The covenant provides that we cannot pay or declare any dividends or make any other restricted payments in excess of the sum of $10.0 million, plus our consolidated net income accrued on and after January 1, 2003. As of December 31, 2018, the cumulative consolidated net income base was $444.3 million, offset by restricted payments of $201.5 million, leaving $242.8 million of cumulative net income free of restrictions. As of December 31, 2018, we are in compliance with all of our debt covenants.

14. SHORT-TERM BORROWINGS

At December 31, 2018 and 2017, we had $294.5 million and $251.0 million, respectively, of short-term borrowings outstanding at the weighted average interest rates of 3.44 percent and 2.42 percent, respectively. We have an aggregate of $370.0 million in credit lines comprised of five unsecured bank credit facilities with four financial institutions, with $220.0 million in total available credit, and a Revolver with five participating Lenders totaling $150.0 million. All of these facilities expire on October 31, 2019 with the exception of the Revolver which is available through October 8, 2020. We incurred commitment fees of $93,300, $131,000 and $145,000 in 2018, 2017 and 2016, respectively. The following table summarizes our short-term borrowing facilities information at December 31, 2018 and 2017.

(in thousands)	Total Facility	LIBOR Based Interest Rate	Outstanding borrowings at December 31, 2018	Outstanding borrowings at December 31, 2017	Available at December 31, 2018
Bank Credit Facility					
Committed revolving credit facility A	$ 55,000	plus 1.00 percent	**$ 25,000**	$ 55,000	**$ 30,000**
Committed revolving credit facility B	30,000	plus 1.00 percent	**15,431**	20,500	**14,569**
Short-term revolving credit note C	50,000	plus 0.80 percent	**50,000**	50,000	**—**
Committed revolving credit facility D	45,000	plus 0.85 percent	**34,672**	40,171	**10,328**
Committed revolving credit facility E	40,000	plus 0.85 percent	**40,000**	—	**—**
Committed revolving credit facility F[2]	150,000	plus up to 1.25 percent	**125,000**	75,000	**25,000**
Total short term credit facilities	$ 370,000		**$ 290,103**	$ 240,671	**$ 79,897**
Book overdrafts[1]			**4,355**	10,298	
Total short-term borrowing			**$ 294,458**	$ 250,969	

[1] If presented, these book overdrafts would be funded through the bank revolving credit facilities.

[2] This committed revolving credit facility includes a restriction that our short-term borrowings, excluding any borrowings under the committed revolving credit facility, shall not exceed $200.0 million.

We are authorized by our Board of Directors to borrow up to $350.0 million of short-term debt, as required, from these short-term lines of credit. These bank credit facilities are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal year, a funded indebtedness ratio of no greater than 65 percent. We are in compliance with all of our debt covenants.

15. Lease Obligations

We have entered into several operating lease arrangements for office space, land, equipment and pipeline facilities. Rent expense related to these leases for 2018, 2017 and 2016 was $3.8 million, $3.6 million and $2.5 million, respectively. As of December 31, 2018, future minimum payments under our current lease agreements are as follows:

Year(s)	2019	2020	2021	2022	2023	Thereafter	Total
(in thousands)							
Expected payments	$2,349	$1,998	$1,761	$1,689	$1,642	$5,398	$14,837

For the years ended December 31, 2018, 2017 and 2016 we paid $2.4 million ,$1.5 million and $1.5 million respectively, for capital lease arrangements related to Sandpiper's capacity, supply and operating agreement and our Mid-Atlantic propane operations' lease arrangement for property in Anne Arundel County, Maryland which it intends to purchase during the first quarter of 2019. Future minimum payments under these lease arrangements are $1.3 million in 2019.

16. Stockholders' Equity

Accumulated Other Comprehensive (Loss)

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options and natural gas futures and swap contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss). In 2018, we elected early adoption of ASU 2018-02, *Reclassification of Certain Tax*

Effects from Accumulated Other Comprehensive Income. Accordingly, we reclassified stranded tax effects resulting from the TCJA from accumulated other comprehensive loss to retained earnings, related to our employee benefit plans and commodity contracts cash flow hedges.

The following table present the changes in the balance of accumulated other comprehensive loss for the years ended December 31, 2018 and 2017. All amounts in the following tables are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2016	$ (5,360)	$ 482	$ (4,878)
Other comprehensive income before reclassifications	281	159	440
Amounts reclassified from accumulated other comprehensive income/(loss)	336	(170)	166
Net current-period other comprehensive income/(loss)	617	(11)	606
As of December 31, 2017	(4,743)	471	(4,272)
Other comprehensive loss before reclassifications	(602)	(3,130)	(3,732)
Amounts reclassified from accumulated other comprehensive income	439	1,759	2,198
Net current-period other comprehensive loss	(163)	(1,371)	(1,534)
Stranded tax reclassification to retained earnings	(1,022)	115	(907)
As of December 31, 2018	**$ (5,928)**	**$ (785)**	**$ (6,713)**

The following table presents amounts reclassified out of accumulated other comprehensive income (loss) for the years ended December 31, 2018, 2017 and 2016. Deferred gains and losses of our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	For the Year Ended December 31,		
(in thousands)	2018	2017	2016
Amortization of defined benefit pension and postretirement plan items:			
Prior service cost [1]	$ 77	$ 77	$ 77
Net gain [1]	(579)	(636)	(871)
Total before income taxes	(502)	(559)	(794)
Income tax benefit	63	223	320
Net of tax	$ (439)	$ (336)	$ (474)
Gains and losses on commodity contracts cash flow hedges			
Propane swap agreements [2]	$ (647)	$ 1,607	$ (322)
Natural gas swaps [2]	197	(822)	—
Natural gas futures [2]	(2,010)	(456)	345
Total before income taxes	(2,460)	329	23
Income tax impact	701	(159)	(3)
Net of tax	$ (1,759)	$ 170	$ 20
Total reclassifications for the period	$ (2,198)	$ (166)	$ (454)

[1] These amounts are included in the computation of net periodic benefits. See Note 17, *Employee Benefit Plans*, for additional details.
[2] These amounts are included in the effects of gains and losses from derivative instruments. See Note 8, *Derivative Instruments*, for additional details.

Amortization of defined benefit pension and postretirement plan items is included in other expense, net and gains and losses on propane swap agreements, call options and natural gas futures contracts are included in cost of sales in the accompanying

consolidated statements of income. The income tax benefit is included in income tax expense in the accompanying consolidated statements of income.

17. EMPLOYEE BENEFIT PLANS

We measure the assets and obligations of the defined benefit pension plans and other postretirement benefits plans to determine the plans' funded status as of the end of the year. We record as a component of other comprehensive income/loss or a regulatory asset the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit costs.

Defined Benefit Pension Plans

We sponsor three defined benefit pension plans: the Chesapeake Pension Plan, the FPU Pension Plan and the Chesapeake unfunded supplemental executive retirement pension plan ("SERP").

The Chesapeake Pension Plan, a qualified plan, was closed to new participants, effective January 1, 1999, and was frozen with respect to additional years of service and additional compensation, effective January 1, 2005. Benefits under the Chesapeake Pension Plan were based on each participant's years of service and highest average compensation, prior to the freezing of the plan. Active participants on the date the Chesapeake Pension Plan was frozen were credited with two additional years of service.

The FPU Pension Plan, a qualified plan, covers eligible FPU non-union employees hired before January 1, 2005 and union employees hired before the respective union contract expiration dates in 2005 and 2006. Prior to the FPU merger, the FPU Pension Plan was frozen with respect to additional years of service and additional compensation, effective December 31, 2009.

The Chesapeake SERP, a nonqualified plan, is comprised of two sub-plans. The first sub-plan was frozen with respect to additional years of service and additional compensation as of December 31, 2004. Benefits under the Chesapeake SERP were based on each participant's years of service and highest average compensation, prior to the freezing of the plan. Active participants on the date the Chesapeake SERP was frozen were credited with two additional years of service. The second sub-plan provides fixed payments for several executives who joined the Company as a result of an acquisition and whose agreements with the Company provided for this benefit.

The unfunded liability for all three plans at both December 31, 2018 and 2017, is included in the other pension and benefit costs liability in our consolidated balance sheets.

The following schedule sets forth the funded status at December 31, 2018 and 2017 and the net periodic cost for the years ended December 31, 2018, 2017 and 2016 for the Chesapeake and FPU Pension Plans as well as the Chesapeake SERP:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP	
At December 31,	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
(in thousands)						
Change in benefit obligation:						
Benefit obligation — beginning of year	**$11,443**	$ 11,355	**$ 64,664**	$ 63,832	**$ 2,428**	$ 2,428
Interest cost	**384**	402	**2,339**	2,482	**83**	89
Actuarial loss (gain)	**(610)**	454	**(4,739)**	1,199	**(74)**	63
Benefits paid	**(505)**	(768)	**(2,887)**	(2,849)	**(152)**	(152)
Benefit obligation — end of year	**10,712**	11,443	**59,377**	64,664	**2,285**	2,428
Change in plan assets:						
Fair value of plan assets — beginning of year	**9,350**	8,668	**48,396**	43,272	**—**	—
Actual return on plan assets	**(647)**	1,144	**(3,113)**	6,025	**—**	—
Employer contributions	**451**	306	**1,205**	1,948	**152**	152
Benefits paid	**(505)**	(768)	**(2,887)**	(2,849)	**(152)**	(152)
Fair value of plan assets — end of year	**8,649**	9,350	**43,601**	48,396	**—**	—
Reconciliation:						
Funded status	**(2,063)**	(2,093)	**(15,776)**	(16,268)	**(2,285)**	(2,428)
Accrued pension cost	**$(2,063)**	$ (2,093)	**$(15,776)**	$(16,268)	**$ (2,285)**	$ (2,428)
Assumptions:						
Discount rate	**4.00%**	3.50%	**4.25%**	3.75%	**4.00%**	3.50%
Expected return on plan assets	**6.00%**	6.00%	**6.50%**	6.50%	**—%**	—%

For the Years Ended December 31, (in thousands)	Chesapeake Pension Plan 2018	Chesapeake Pension Plan 2017	Chesapeake Pension Plan 2016	FPU Pension Plan 2018	FPU Pension Plan 2017	FPU Pension Plan 2016	Chesapeake SERP 2018	Chesapeake SERP 2017	Chesapeake SERP 2016
Components of net periodic pension cost:									
Interest cost	$ 384	$ 402	$ 421	$ 2,339	$ 2,482	$ 2,525	$ 83	$ 89	$ 91
Expected return on assets	(542)	(495)	(501)	(3,091)	(2,779)	(2,702)	—	—	
Amortization of actuarial loss	343	399	459	404	513	519	101	87	87
Settlement expense	—	—	161	—	—	—			
Net periodic pension cost[1]	185	306	540	(348)	216	342	184	176	178
Amortization of pre-merger regulatory asset	—	—	—	761	761	761	—	—	—
Total periodic cost	$ 185	$ 306	$ 540	$ 413	$ 977	$ 1,103	$ 184	$ 176	$ 178
Assumptions:									
Discount rate	3.50%	3.75%	3.75%	3.75%	4.00%	4.00%	3.50%	3.75%	3.75%
Expected return on plan assets	6.00%	6.00%	6.00%	6.50%	6.50%	6.50%	—%	—%	—%

(1) As a result of our adoption of ASU 2017-07 on January 1, 2018, the "other than service" cost components of the net periodic costs have been recorded or reclassified to other income (expense), net in the consolidated statements of income.

Included in the net periodic costs for the FPU Pension Plan is continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated operations for the changes in funded status that occurred, but were not recognized as part of net periodic cost, prior to the merger with Chesapeake Utilities in October 2009. This was previously deferred as a regulatory asset to be recovered through rates pursuant to an order by the Florida PSC. The unamortized balance of this regulatory asset was $543,000 and $1.3 million at December 31, 2018 and 2017, respectively.

Our funding policy provides that payments to the trustee of each qualified plan shall be equal to at least the minimum funding requirements of the Employee Retirement Income Security Act of 1974. The following schedule summarizes the assets of the Chesapeake Pension Plan and the FPU Pension Plan, by investment type, at December 31, 2018, 2017 and 2016:

At December 31,	Chesapeake Pension Plan 2018	Chesapeake Pension Plan 2017	Chesapeake Pension Plan 2016	FPU Pension Plan 2018	FPU Pension Plan 2017	FPU Pension Plan 2016
Asset Category						
Equity securities	49.02%	52.70%	52.93%	50.04%	55.17%	53.18%
Debt securities	40.98%	37.79%	37.64%	41.06%	36.56%	37.74%
Other	10.00%	9.51%	9.43%	8.90%	8.27%	9.08%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The investment policy of both the Chesapeake Utilities and FPU Pension Plans is designed to provide the capital assets necessary to meet the financial obligations of the plans. The investment goals and objectives are to achieve investment returns that, together with contributions, will provide funds adequate to pay promised benefits to present and future beneficiaries of the plans, earn a long-term investment return in excess of the growth of the plans' retirement liabilities, minimize pension expense and cumulative contributions resulting from liability measurement and asset performance, and maintain a diversified portfolio to reduce the risk of large losses.

The following allocation range of asset classes is intended to produce a rate of return sufficient to meet the plans' goals and objectives:

Asset Allocation Strategy		
Asset Class	**Minimum Allocation Percentage**	**Maximum Allocation Percentage**
Domestic Equities (Large Cap, Mid Cap and Small Cap)	14%	32%
Foreign Equities (Developed and Emerging Markets)	13%	25%
Fixed Income (Inflation Bond and Taxable Fixed)	26%	40%
Alternative Strategies (Long/Short Equity and Hedge Fund of Funds)	6%	14%
Diversifying Assets (High Yield Fixed Income, Commodities, and Real Estate)	7%	19%
Cash	0%	5%

Due to periodic contributions and different asset classes producing varying returns, the actual asset values may temporarily move outside of the intended ranges. The investments are monitored on a quarterly basis, at a minimum, for asset allocation and performance.

At December 31, 2018 and 2017, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

	Fair Value Measurement Hierarchy							
	At December 31, 2018				At December 31, 2017			
Asset Category	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
(in thousands)								
Mutual Funds - Equity securities								
U.S. Large Cap [1]	$ 3,399	$ —	$ —	$ 3,399	$ 4,245	$ —	$ —	$ 4,245
U.S. Mid Cap [1]	1,478	—	—	1,478	1,775	—	—	1,775
U.S. Small Cap [1]	670	—	—	670	918	—	—	918
International [2]	9,226	—	—	9,226	11,916	—	—	11,916
Alternative Strategies [3]	5,726	—	—	5,726	5,528	—	—	5,528
	20,499	—	—	20,499	24,382	—	—	24,382
Mutual Funds - Debt securities								
Fixed income [4]	18,630	—	—	18,630	18,454	—	—	18,454
High Yield [4]	2,818	—	—	2,818	2,772	—	—	2,772
	21,448	—	—	21,448	21,226	—	—	21,226
Mutual Funds - Other								
Commodities [5]	1,902	—	—	1,902	2,154	—	—	2,154
Real Estate [6]	2,216	—	—	2,216	2,300	—	—	2,300
Guaranteed deposit [7]	—	—	627	627	—	—	436	436
	4,118	—	627	4,745	4,454	—	436	4,890
Total Pension Plan Assets in fair value hierarchy	$46,065	$ —	$ 627	46,692	$50,062	$ —	$ 436	50,498
Investments measured at net asset value [8]				5,558				7,248
Total Pension Plan Assets				$ 52,250				$ 57,746

[1] Includes funds that invest primarily in United States common stocks.
[2] Includes funds that invest primarily in foreign equities and emerging markets equities.
[3] Includes funds that actively invest in both equity and debt securities, funds that sell short securities and funds that provide long-term capital appreciation. The funds may invest in debt securities below investment grade.
[4] Includes funds that invest in investment grade and fixed income securities.
[5] Includes funds that invest primarily in commodity-linked derivative instruments and fixed income securities.
[6] Includes funds that invest primarily in real estate.
[7] Includes investment in a group annuity product issued by an insurance company.

[8] Certain investments that were measured at net asset value per share have not been classified in the fair value hierarchy. These amounts are presented to reconcile to total pension plan assets.

At December 31, 2018 and 2017, all of the investments were classified under the same fair value measurement hierarchy (Level 1 through Level 3) described under Note 9, *Fair Value of Financial Instruments*. The Level 3 investments were recorded at fair value based on the contract value of annuity products underlying guaranteed deposit accounts, which was calculated using discounted cash flow models. The contract value of these products represented deposits made to the contract, plus earnings at guaranteed crediting rates, less withdrawals and fees.

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2018 and 2017:

	For the Year Ended December 31,	
	2018	2017
(in thousands)		
Balance, beginning of year	$ 436	$ 498
Purchases	**1,674**	2,271
Transfers in	**2,375**	1,743
Disbursements	**(3,872)**	(4,101)
Investment income	**14**	25
Balance, end of year	$ 627	$ 436

Other Postretirement Benefits Plans

We sponsor two defined benefit postretirement health plans: the Chesapeake Postretirement Plan and the FPU Medical Plan. The following table sets forth the funded status at December 31, 2018 and 2017 and the net periodic cost for the years ended December 31, 2018, 2017, and 2016:

	Chesapeake Postretirement Plan		FPU Medical Plan	
At December 31,	2018	2017	2018	2017
(in thousands)				
Change in benefit obligation:				
Benefit obligation — beginning of year	$ **1,128**	$ 1,132	$ **1,287**	$ 1,349
Interest cost	**38**	41	**47**	50
Plan participants contributions	**136**	118	**41**	48
Actuarial loss (gain)	**(131)**	72	**(89)**	(48)
Benefits paid	**(169)**	(235)	**(99)**	(112)
Benefit obligation — end of year	**1,002**	1,128	**1,187**	1,287
Change in plan assets:				
Fair value of plan assets — beginning of year	**—**	—	**—**	—
Employer contributions[1]	**33**	117	**58**	64
Plan participants contributions	**136**	118	**41**	48
Benefits paid	**(169)**	(235)	**(99)**	(112)
Fair value of plan assets — end of year	**—**	—	**—**	—
Reconciliation:				
Funded status	**(1,002)**	(1,128)	**(1,187)**	(1,287)
Accrued postretirement cost	$ **(1,002)**	$ (1,128)	$ **(1,187)**	$ (1,287)
Assumptions:				
Discount rate	**4.00%**	3.50%	**4.25%**	3.75%

[1] The Chesapeake Postretirement Plan does not receive a Medicare Part-D subsidy. The FPU Medical Plan did not receive a significant subsidy for the post-merger period.

Notes to the Consolidated Financial Statements

Net periodic postretirement benefit costs for 2018, 2017, and 2016 include the following components:

	Chesapeake Postretirement Plan			FPU Medical Plan		
For the Years Ended December 31, *(in thousands)*	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Components of net periodic postretirement cost:						
Interest cost	$ 38	$ 41	$ 43	$ 47	$ 50	$ 55
Amortization of actuarial loss	58	53	64	—	—	—
Amortization of prior service cost (credit)	(77)	(77)	(77)	—	—	—
Net periodic cost	19	17	30	47	50	55
Amortization of pre-merger regulatory asset	—	—	—	8	8	8
Total periodic cost[1]	$ 19	$ 17	$ 30	$ 55	$ 58	$ 63
Assumptions						
Discount rate	3.50%	3.75%	3.75%	3.75%	4.00%	4.00%

(1) As a result of our adoption of ASU 2017-07 on January 1, 2018, the "other than service" cost components of the net periodic costs have been recorded or reclassified to other income (expense), net in the condensed consolidated statements of income.

Similar to the FPU Pension Plan, continued amortization of the FPU Medical Plan regulatory asset related to the unrecognized cost prior to the merger with Chesapeake Utilities was included in the net periodic cost. The unamortized balance of this regulatory asset was $14,000 and $22,000 at December 31, 2018 and 2017, respectively.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive loss or as a regulatory asset as of December 31, 2018:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ —	$ —	$ —	$ (524)	$ —	$ (524)
Net loss (gain)	3,865	18,544	559	578	(79)	23,467
Total	$ 3,865	$ 18,544	$ 559	$ 54	$ (79)	$ 22,943
Accumulated other comprehensive loss (gain) pre-tax[1]	$ 3,865	$ 3,523	$ 559	$ 54	$ (15)	$ 7,986
Post-merger regulatory asset	—	15,021	—	—	(64)	14,957
Subtotal	3,865	18,544	559	54	(79)	22,943
Pre-merger regulatory asset	—	543	—	—	14	557
Total unrecognized cost	$ 3,865	$ 19,087	$ 559	$ 54	$ (65)	$ 23,500

(1) The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2018 is net of income tax benefits of $2.1 million.

Pursuant to a Florida PSC order, FPU continues to record as a regulatory asset a portion of the unrecognized pension and postretirement benefit costs after the merger with Chesapeake Utilities related to its regulated operations, which is included in the above table as a post-merger regulatory asset. FPU also continues to maintain and amortize a portion of the unrecognized pension and postretirement benefit costs prior to the merger with Chesapeake Utilities related to its regulated operations, which is shown as a pre-merger regulatory asset.

Assumptions

The assumptions used for the discount rate to calculate the benefit obligations were based on the interest rates of high-quality bonds in 2018, considering the expected lives of each of the plans. In determining the average expected return on plan assets for each applicable plan, various factors, such as historical long-term return experience, investment policy and current and expected allocation, were considered. Since Chesapeake Utilities' plans and FPU's plans have different expected plan lives, particularly in light of the lump-sum-payment option provided in the Chesapeake Pension Plan, different assumptions regarding discount rate and expected return on plan assets were selected for Chesapeake Utilities' and FPU's plans. Since both pension plans are frozen with respect to additional years of service and compensation, the rate of assumed compensation increases is not applicable.

The health care inflation rate for 2018 used to calculate the benefit obligation is 5.0 percent for medical and 6.0 percent for prescription drugs for the Chesapeake Postretirement Plan; and 5.0 percent for both medical and prescription drugs for the FPU Medical Plan.

Estimated Future Benefit Payments

In 2019, we expect to contribute $163,000 and $1.2 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $383,000 to the Chesapeake SERP. We also expect to contribute $96,000 and $94,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2019.

The schedule below shows the estimated future benefit payments for each of the plans previously described:

(in thousands)	Chesapeake Pension Plan[1]	FPU Pension Plan[1]	Chesapeake SERP[2]	Chesapeake Postretirement Plan[2]	FPU Medical Plan[2]
2019	$ 528	$ 3,091	$ 383	$ 96	$ 94
2020	$ 529	$ 3,221	$ 150	$ 85	$ 87
2021	$ 736	$ 3,299	$ 148	$ 82	$ 91
2022	$ 595	$ 3,485	$ 147	$ 81	$ 93
2023	$ 1,244	$ 3,558	$ 145	$ 64	$ 80
Years 2024 through 2028	$ 3,866	$ 18,570	$ 744	$ 275	$ 402

[1] The pension plan is funded; therefore, benefit payments are expected to be paid out of the plan assets.
[2] Benefit payments are expected to be paid out of our general funds.

Retirement Savings Plan

For the years ended December 31, 2018, 2017 and 2016, we sponsored a 401(k) Retirement Savings Plan. This plan is offered to all eligible employees who have completed three months of service. We match 100 percent of eligible participants' pre-tax contributions to the Retirement Savings Plan up to a maximum of six percent of eligible compensation. The employer matching contribution is made in cash and is invested based on a participant's investment directions. In addition, we may make a discretionary supplemental contribution to participants in the plan, without regard to whether or not they make pre-tax contributions. Any supplemental employer contribution is generally made in our common stock. With respect to the employer match and supplemental employer contribution, employees are 100 percent vested after two years of service or upon reaching 55 years of age while still employed by us. New employees who do not make an election to contribute and do not opt out of the Retirement Savings Plan will be automatically enrolled at a deferral rate of three percent, and the automatic deferral rate will increase by one percent per year up to a maximum of ten percent. All contributions and matched funds can be invested among the mutual funds available for investment.

Employer contributions to our Retirement Savings Plan totaled $5.5 million, $5.0 million, and $4.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, there were 831,183 shares of our common stock reserved to fund future contributions to the Retirement Savings Plan.

Non-Qualified Deferred Compensation Plan

Members of our Board of Directors, and officers designated by the Compensation Committee, are eligible to participate in the Non-Qualified Deferred Compensation Plan. Directors can elect to defer any portion of their cash or stock compensation and officers can defer up to 80 percent of their base compensation, cash bonuses or any amount of their stock bonuses (net of required withholdings). Officers may receive a matching contribution on their cash compensation deferrals up to six percent of their

compensation, provided it does not duplicate a match they receive in the Retirement Savings Plan. Stock bonuses are not eligible for matching contributions. Participants are able to elect the payment of deferred compensation to begin on a specified future date or upon separation from service. Additionally, participants can elect to receive payments upon the earlier or later of a fixed date or separation from service. The payments can be made in one lump sum or annual installments for up to 15 years.

All obligations arising under the Non-Qualified Deferred Compensation Plan are payable from our general assets, although we have established a Rabbi Trust to informally fund the plan. Deferrals of cash compensation may be invested by the participants in various mutual funds (the same options that are available in the Retirement Savings Plan). The participants are credited with gains or losses on those investments. Deferred stock compensation may not be diversified. The participants are credited with dividends on our common stock in the same amount that is received by all other stockholders. Such dividends are reinvested into our common stock. Assets held in the Rabbi Trust, recorded as Investments on the consolidated balance sheet, had a fair value of $6.7 million at both December 31, 2018 and 2017. (See *Note 10, Investments*, for further details). The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Deferrals of officer base compensation and cash bonuses and directors' cash retainers are paid in cash. All deferrals of executive performance shares, which represent deferred stock units, and directors' stock retainers are paid in shares of our common stock, except that cash is paid in lieu of fractional shares. The value of our stock held in the Rabbi Trust is classified within the stockholders' equity section of the consolidated balance sheets and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Non-Qualified Deferred Compensation Plan totaled $3.9 million and $3.4 million at December 31, 2018 and 2017, respectively, which are also shown as a deduction against stockholders' equity in the consolidated balance sheet.

18. SHARE-BASED COMPENSATION PLANS

Our non-employee directors and key employees have been granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period. We have 475,099 shares of common stock reserved for issuance under the SICP.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the SICP for the years ended December 31, 2018, 2017 and 2016:

	For the Year Ended December 31,		
	2018	2017	2016
(in thousands)			
Awards to non-employee directors	$ 539	$ 540	$ 580
Awards to key employees	2,871	1,950	1,787
Total compensation expense	3,410	2,490	2,367
Less: tax benefit	(934)	(1,003)	(952)
Share-based compensation amounts included in net income	$ 2,476	$ 1,487	$ 1,415

Stock Options

There were no stock options outstanding at December 31, 2018 or 2017, nor were any stock options issued during the years 2016 through 2018.

Non-employee Directors

Shares granted to non-employee directors are issued in advance of these directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2017, each of our non-employee directors received an annual retainer of 835 shares of common stock under the SICP for board service through the 2018 Annual Meeting of Stockholders; as a group, 7,515 shares, with a weighted average fair value of $71.80, were issued and vested in 2017. In May 2018, each of our non-employee directors received an annual retainer of 792 shares of common stock under the SICP for board service through the 2019 Annual Meeting of Stockholders; accordingly, 7,128 shares, with a weighted average fair value of $75.70, were issued and vested in 2018.

The intrinsic values of the shares granted to our non-employee directors are equal to the fair value of these awards on the date of grant. At December 31, 2018, there was $180,000 of unrecognized compensation expense related to these awards. This expense will be fully recognized by April 2019, which approximates the expected remaining service period of those directors.

Key Employees

Our Compensation Committee is authorized to grant our key employees the right to receive awards of shares of our common stock, contingent upon the achievement of established performance goals and subject to SEC transfer restrictions once awarded.

We currently have several outstanding multi-year performance plans, which are based upon the successful achievement of long-term goals, growth and financial results and comprise both market-based and performance-based conditions or targets. The fair value per share, tied to a performance-based condition or target, is equal to the market price per share on the grant date. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each share granted.

The table below presents the summary of the stock activity for awards to key employees:

	Number of Shares	Weighted Average Fair Value
Outstanding — December 31, 2016	115,091	$ 51.85
Granted	52,355	$ 63.42
Vested	(32,926)	$ 38.88
Expired	(1,878)	$ 39.97
Outstanding — December 31, 2017	132,642	$ 59.31
Granted	49,494	$ 67.76
Vested	(29,786)	$ 47.39
Vested - Accelerated pursuant to separation agreement [1]	(16,676)	$ 75.78
Expired	(3,933)	$ 49.66
Outstanding — December 31, 2018	**131,741**	**$ 67.24**

[1] Includes 2,569 shares that were forfeited

The intrinsic value of these awards was $10.7 million, $10.4 million and $7.7 million in 2018, 2017 and 2016, respectively. At December 31, 2018, there was $2.1 million of unrecognized compensation cost related to these awards, which is expected to be recognized during 2019 through 2020.

In 2018, 2017 and 2016, we withheld shares with a value at least equivalent to the employees' minimum statutory obligation for the applicable income and other employment taxes, and remitted the cash to the appropriate taxing authorities with the executives electing to receive the net shares. The below table presents the number of shares withheld, amounts remitted to taxing authorities and the tax benefits associated with these obligations:

	For the Year Ended December 31,		
	2018	**2017**	**2016**
(amounts except shares, in thousands)			
Shares withheld to satisfy tax obligations	**10,436**	10,269	12,031
Amounts remitted to tax authorities to satisfy obligations	**$ 1,210**	$ 692	$ 770
Tax benefit associated with settlement of share based payments	**$ —**	$ 349	285

In June 2018, the Company and a former executive officer entered into a separation agreement and release (the "Separation Agreement"). Pursuant to the Separation Agreement, three awards, representing a total of 14,107 shares of common stock previously granted to the executive officer under the SICP, immediately vested at the time of separation, and an additional 2,569 shares were forfeited. We settled the awards that vested in cash and recognized $1.1 million as share-based compensation expense.

19. RATES AND OTHER REGULATORY ACTIVITIES

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC.

Delaware

Underserved Area Rates: In December 2017, we filed an application requesting authorization to utilize existing expansion area tariff rates to serve customers located outside of the current Sussex County, Delaware expansion area boundaries that cannot be economically served under the regular tariff rates. In June 2018, we reached a settlement agreement with the relevant parties, which allows us to utilize higher rates for areas outside of our existing expansion area. The Delaware PSC unanimously approved the settlement at its public meeting on July 10, 2018. The new rate schedule became effective on August 1, 2018.

CGS: In June 2018, we filed with the Delaware PSC an application requesting approval of the acquisition, and subsequent conversion to natural gas of certain CGS located within our service territory. We requested the establishment of regulatory accounting treatment and valuation of the proposed acquisition, approval of a methodology to set new distribution rates for CGS customers and approval of a new system-wide tariff rate that will recover CGS conversion costs. The application included a request that the Delaware PSC regulate the propane CGS systems after their acquisition but before conversion to natural gas. In late 2018, the Delaware PSC ruled that it did not have jurisdiction over these propane CGS systems and could not approve the methodology given the lack of jurisdiction. We are considering proposing legislation to clarify the Delaware PSC jurisdiction or we may redesign the application and re-file.

Effect of the TCJA on customers: The Delaware PSC issued an order requiring all rate-regulated utilities to: (i) file estimates of the impact of the TCJA on their cost of service for the most recent test year available (including new rate schedules), and (ii) propose procedures for changing rates to reflect those impacts on or before March 31, 2018. In addition, on February 1, 2018, the Delaware PSC issued an order requiring Delaware rate-regulated public utilities to accrue regulatory liabilities reflecting the impacts of changes in the federal corporate income tax laws. In compliance with the Delaware PSC order, we have established a regulatory liability to reflect the estimated impacts of the changes in the federal corporate income tax rate. On May 31, 2018, our Delaware Division filed the information requested by the PSC, including an updated report reflecting the impact of the TCJA. On January 31, 2019, the Delaware PSC approved the as-filed Delaware Division Delivery Service Rates reflecting the impact of the TCJA. The new rates will go into effect March 1, 2019, and the Company will have to complete refunds back to February 2018, per the Commission's previous order, by June 30, 2019. The order also provides for a line item billing credit to go into effect on April 1, 2019, for the return of the excess deferred income taxes. Additional information on the TCJA impact is included in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

Maryland

Effect of the TCJA on customers: In April 2018, the Maryland PSC issued orders related to the TCJA impact on both the Maryland Division and Sandpiper operations. Please see the actions taken in conjunction with these orders in the TCJA table at the end of this Note 19, *Rates and Other Regulatory Activities*. Additionally, if in the future the Maryland Division or Sandpiper identifies any additional tax savings, we must submit an additional filing to the Maryland PSC in order to return those savings to customers as soon as possible.

Florida

Florida Electric Reliability/Modernization Pilot Program: In July 2017, our Florida electric operations filed a petition with the Florida PSC requesting approval to include $15.2 million of certain capital project expenditures in its rate base and to adjust its base rates accordingly. These expenditures are designed to improve the stability and safety of the electric system, while enhancing the capability of our electrical grid. In December 2017, the Florida PSC approved this petition, effective January 1, 2018. The settlement agreement prescribed the methodology for adjusting the new rates based on the lower federal income tax rate and the process and methodology regarding the refund of deferred income taxes, reclassified as a regulatory liability, as a result of the TCJA. More details about this methodology are included in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

Electric Limited Proceeding-Storm Recovery: In February 2018, FPU filed a petition with the Florida PSC, requesting recovery of incremental storm restoration costs related to several hurricanes and tropical storms, along with the replenishment of the storm reserve to its pre-storm level of $1.5 million. As a result of these hurricanes and tropical storms, FPU's storm reserve was depleted and, at the time of this filing, had a deficit of $779,000. We requested approval of a surcharge of $1.82 per kilowatt hour for two years to recover storm-related costs and replenish the storm reserve. FPU filed written testimony on this matter in August 2018. This matter was heard before the Florida PSC in December 2018, final legal briefs were submitted and, on January 14, 2019, and is scheduled for approval at Agenda on March 5, 2019.

In October 2018, Hurricane Michael passed through Florida Public Utilities Company's ("FPU") electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure resulting in 100 percent of its customers losing electrical service. FPU has restored service to those customers who were able to accept service following Hurricane Michael after a significant hurricane restoration effort. In conjunction with restoring these services, FPU expended over $60.0 million to restore service, which has been recorded as new plant and equipment or charged against FPU's storm reserve. We are preparing the necessary regulatory filings to seek recovery for the costs incurred, including replenishment of FPU's storm reserve. In conjunction with the hurricane-related expenditures, we executed two 13-month unsecured term loans as temporary financing, each in the amount of $30.0 million. The interest cost associated with these loans is LIBOR plus 75 basis points. One of the term loans was executed in December 2018 and the other was executed in January 2019. The storm did not have a material impact on the Company's financial results in 2018, and is not expected to have a significant impact going forward assuming reasonable regulatory treatment.

Effect of the TCJA on customers: In February 2018, the Florida PSC opened dockets to consider the impacts associated with the TCJA. In May 2018, FPU's natural gas division filed petitions and supporting testimony regarding the disposition of the related impacts of the TCJA. Hearings on this matter took place in November 2018, The Florida PSC approved staff's recommendations on February 5, 2019. Final orders were issued on February 25, 2019, and are subject to a 30-day appeal period. Staff's recommendations are summarized in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

Eastern Shore

2017 Expansion Project: In October 2017, the FERC issued a Certificate of Public Convenience and Necessity authorizing Eastern Shore to construct this project, the largest expansion in Eastern Shore's history. The facilities include approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional compressor unit at Eastern Shore's existing Daleville compressor station in Chester County, Pennsylvania; and approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. Eastern Shore entered into precedent agreements with seven existing customers, including three affiliates of Chesapeake Utilities, for a total of 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system and an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities.

The first phase of the project was placed into service in December 2017 and, as of December 31, 2018, we have substantially completed construction. The TETLP interconnect upgrade was placed into service in December 2017, and the Fair Hill Loop, the Jennersville Loop, the Daleville Compressor Station, the Seaford-Millsboro Connector, and the Millsboro Pressure Control Station were placed into service at various dates in 2018. The Parkesburg Loop was placed into service in January 2019. The few remaining segments are expected to be placed into service in various phases during the first half of 2019.

2017 Rate Case Filing: In January 2017, Eastern Shore filed a base rate proceeding with the FERC. In August 2017, Eastern Shore implemented the proposed new rates, subject to refund, based on the outcome of the rate proceeding. Eastern Shore recorded incremental revenue of approximately $3.7 million for the year ended December 31, 2017, and established a regulatory liability to reserve a portion of the total incremental revenues generated by the new rates pending FERC approval of a settlement agreement and refunds to customers according to the terms of the settlement. The FERC approved the settlement agreement in February 2018, and it became final in March 2018. In April 2018, Eastern Shore refunded to its customers, with interest, the difference between the proposed rates and the settlement rates. Exclusive of the TCJA impact, which is discussed below, base rates increased, on an annual basis, by approximately $9.8 million.

Effect of the TCJA on customers: In March 2018, Eastern Shore filed with the FERC its revised base rates, reflecting the reduction in its federal corporate income tax rate. These adjusted base rates became effective January 1, 2018 and will generate approximately $6.6 million in incremental margin, on an annual basis. Other information about the impact of the TCJA on ESNG has been included in the table at the end of this Note 19, *Rates and Other Regulatory Activities*.

In October 2018, the FERC issued an order granting a waiver to Eastern Shore. In April 2018, Eastern Shore consummated a filing, which included its comments associated with the United Airlines, Inc. vs. FERC proceeding and requested confirmation from the FERC that Eastern Shore is not required to provide an informational filing because of its implementation of lower rates in accordance with the 2017 rate case settlement agreement.

Del-Mar Energy Pathway Project: In September 2018, Eastern Shore filed a Certificate Application with the FERC, requesting authorization to construct and operate the Del-Mar Energy Pathway project, which will provide an additional 14,300 Dts/d of capacity to four customers. Facilities to be constructed include six miles of pipeline looping in Delaware; 13 miles of new mainline extension in Sussex County, Delaware and Somerset County, Maryland; and new pressure control and delivery stations in these counties. The benefits of this project include: (i) further natural gas transmission pipeline infrastructure in eastern Sussex County, Delaware, and (ii) extension of Eastern Shore's pipeline system, for the first time, into Somerset County, Maryland. During the fourth quarter of 2018, the FERC held a full project area scoping meeting in Sussex County, Delaware and issued a Notice of Schedule for Environmental Review, indicating issuance of its Environmental Assessment for the Del-Mar Energy Pathway project by April 1, 2019.

Summary TCJA Table

	Regulatory Liabilities related to Excess Accumulated Deferred Income Taxes ("ADIT")		Status of Customer Rate impact related to 35 percent to 21 percent rate change
Operation and Regulatory Jurisdiction	Amount (in thousands)	Status	
Eastern Shore (FERC)	$34,190	Will be addressed in Eastern Shore's next rate case filing	Implemented one-time bill credit (totaling $900,000) in April 2018 - Customer rates adjusted in April, 2018
Delaware Division (Delaware PSC)	$13,262	In January 2019, PSC approved amortization of ADIT and corresponding customer rate reductions effective March 1, 2019.	Customer rates to be adjusted March 1, 2019. One-time bill credit to be implemented during the second quarter.
Maryland Division (Maryland PSC)	$4,211	In May 2018, PSC approved amortization of ADIT and corresponding customer rate reductions commenced	Implemented one-time bill credit (totaling $365,000) in July 2018 - Customer rates adjusted effective May 1, 2018
Sandpiper Energy (Maryland PSC)	$3,815	In May 2018, PSC approved amortization of ADIT and corresponding customer rate reductions commenced	Implemented one-time bill credit (totaling $608,000) in July 2018 - Customer rates adjusted effective May 1, 2018
Chesapeake Florida Gas Division/Central Florida Gas (Florida PSC)	$8,471	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019
		The order states that the net ADIT liability would be amortized and retained by the Company pursuant to the prescribed schedule	No one-time bill credit or adjustment in rates would be applied; the tax savings arising from the TCJA rate reduction would be retained
FPU Natural Gas (includes FPU, Fort Meade, and Indiantown) (Florida PSC)	$19,505	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019
		The order states that the net ADIT liability would be amortized and retained by the Company pursuant to the prescribed schedule	No one-time bill credit or adjustment in rates would be applied; the tax savings arising from the TCJA rate reduction would be retained
FPU Electric (Florida PSC)	$5,995	In January 2019, PSC approved amortization of ADIT through purchased power cost recovery, storm reserve and rates.	TCJA benefit will flow back to its customers through a combination of reductions to the fuel cost recovery rate, base rates, as well as application to the storm reserve over the next several years

Regulatory Assets and Liabilities

At December 31, 2018 and 2017, our regulated utility operations had recorded the following regulatory assets and liabilities included in our consolidated balance sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers' rates.

(in thousands)	As of December 31, 2018	2017
Regulatory Assets		
Under-recovered purchased fuel and conservation cost recovery [1]	$ 4,631	$ 9,869
Under-recovered GRIP revenue [2]	165	164
Deferred postretirement benefits [3]	15,517	15,498
Deferred conversion and development costs [1]	16,727	11,735
Environmental regulatory assets and expenditures [4]	2,731	3,222
Acquisition adjustment [5]	33,255	39,992
Loss on reacquired debt [6]	942	1,031
Other	3,250	4,994
Total Regulatory Assets	$ 77,218	$ 86,505
Regulatory Liabilities		
Self-insurance [7]	$ 947	$ 1,013
Over-recovered purchased fuel and conservation cost recovery [1]	5,443	2,048
Over-recovered GRIP revenue [2]	1,563	2,245
Storm reserve [7]	677	669
Accrued asset removal cost [8]	42,401	40,948
Deferred income taxes due to rate change [9]	91,162	98,492
Other	729	2,048
Total Regulatory Liabilities	$ 142,922	$ 147,463

[1] We are allowed to recover the asset or are required to pay the liability in rates. We do not earn an overall rate of return on these assets.
[2] The Florida PSC allowed us to recover through a surcharge, capital and other program-related-costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services (defined as any material other than coated steel or plastic) in FPU's natural gas distribution, Fort Meade division and Chesapeake Utilities' Central Florida Gas division. We are allowed to recover the asset or are required to pay the liability in rates related to GRIP.
[3] The Florida PSC allowed FPU to treat as a regulatory asset the portion of the unrecognized costs pursuant to ASC Topic 715, *Compensation - Retirement Benefits*, related to its regulated operations. See Note 17, *Employee Benefit Plans*, for additional information.
[4] All of our environmental expenditures incurred to date and our current estimate of future environmental expenditures have been approved by various PSCs for recovery. See Note 20, *Environmental Commitments and Contingencies*, for additional information on our environmental contingencies.
[5] We are allowed to include the premiums paid in various natural gas utility acquisitions in Florida in our rate bases and recover them over a specific time period pursuant to the Florida PSC approvals. Included in these amounts are $543,000 of the premium paid by FPU, $34.2 million of the premium paid by us in 2009, including a gross up for income tax, because it is not tax deductible, and $746,000 of the premium paid by FPU in 2010.
[6] Gains and losses resulting from the reacquisition of long-term debt are amortized over future periods as adjustments to interest expense in accordance with established regulatory practice.
[7] We have self-insurance and storm reserves in our Florida regulated energy operations that allow us to collect through rates amounts to be used against general claims, storm restoration costs and other losses as they are incurred.
[8] See Note 1, *Summary of Significant Accounting Policies*, for additional information on our asset removal cost policies.
[9] We recorded a regulatory liability for our regulated businesses related to the revaluation of accumulated deferred tax assets/liabilities as a result of the TCJA. Based upon the regulatory proceedings, we will pass back the respective portion of the excess accumulated deferred taxes to rate payers. See Note 12, *Income Taxes*, for additional information.

20. Environmental Commitments and Contingencies

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remediate, at current and former operating sites, the effect on the environment of the disposal or release of specified substances.

MGP Sites

We have participated in the investigation, assessment or remediation of, and have exposures at, seven former MGP sites. We have received approval for recovery of clean-up costs in rates for six sites located in Salisbury, Maryland, Seaford, Delaware and Winter

Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the MDE regarding a former MGP site located in Cambridge, Maryland.

As of December 31, 2018, we had approximately $9.1 million in environmental liabilities, related to FPU's MGP sites in Key West, Pensacola, Sanford and West Palm Beach. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to its MGP sites. As of December 31, 2018, we have recovered approximately $11.5 million, leaving approximately $2.5 million in regulatory assets for future recovery from FPU's customers.

Environmental liabilities for our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental remediation and related activities, including any potential future remediation costs for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.

The following is a summary of our remediation status and estimated costs to implement clean-up of our key MGP sites:

MGP Site (Jurisdiction)	Status	Estimated Cost to Clean Up (Expect to Recover through Rates)
West Palm Beach (Florida)	Remedial actions approved by Florida Department of Environmental Protection have been implemented on the east parcel of the site. Similar remedial actions expected to be implemented on other remaining portions.	Between $4.5 million to $15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.
Sanford (Florida)	In March 2018, the EPA approved a "site-wide ready for anticipated use" status, which is the final step before delisting a site. Construction has been completed and restrictive covenants are in place to ensure protection of human health. The only remaining activity is long-term groundwater monitoring. It is unlikely that FPU will incur any significant future costs associated with the site.	FPU's remaining remediation expenses, including attorneys' fees and costs, are anticipated to be less than $10,000.
Winter Haven (Florida)	Remediation is ongoing.	Not expected to exceed $425,000, which includes costs of implementing institutional controls at the site.
Seaford (Delaware)	Proposed plan for implementation approved by Delaware Department of Natural Resources and Environmental Control in July 2017. Site assessment is ongoing.	$273,000 to $465,000.
Cambridge (Maryland)	Currently in discussions with MDE.	Unable to estimate.

21. OTHER COMMITMENTS AND CONTINGENCIES

Natural Gas, Electric and Propane Supply

Our Delmarva Peninsula natural gas distribution operations have asset management agreements with PESCO to manage their natural gas transportation and storage capacity. The agreements were effective as of April 1, 2017, and each has a three-year term, expiring on March 31, 2020. Previously, the Delaware PSC approved PESCO to serve as an asset manager with respect to our Delaware Division.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with Eastern Gas & Water Investment Company, LLC ("EGWIC") to purchase propane through May 2019. Sandpiper's remaining commitment is approximately 1.2 million gallons. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices.

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC through May 2019. Sharp's current annual commitment is estimated at approximately 1.2 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC; neither agreement permits the set off of the rights and obligations in one agreement against those in the other agreement.

Chesapeake Utilities' Florida Division has firm transportation service contracts with FGT and Gulfstream. Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake Utilities is contingently liable to FGT and Gulfstream should any party that acquired the capacity through release fail to pay the capacity charge.

FPU's electric supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with FPL requires FPU to meet or exceed a debt service coverage ratio of 1.25 times based on the results of the prior 12 months. If FPU fails to meet this ratio, it must provide an irrevocable letter of credit or pay all amounts outstanding under the agreement within five business days. FPU's electric supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken, or proposed to be taken, to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could also result in FPU having to provide an irrevocable letter of credit. As of December 31, 2018, FPU was in compliance with all of the requirements of its fuel supply contracts.

Eight Flags provides electricity and steam generation services through its CHP plant located on Amelia Island, Florida. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU pursuant to a 20-year power purchase agreement for distribution to our electric customers. In July 2016, Eight Flags also started selling steam, pursuant to a separate 20-year contract, to the landowner on which the CHP plant is located. The CHP plant is powered by natural gas transported by FPU through its distribution system and Peninsula Pipeline through its intrastate pipeline.

The total purchase obligations for natural gas, electric and propane supplies are as follows:

Year	2019	2020-2021	2022-2023	Beyond 2023	Total
(in thousands)					
Purchase Obligations	$ 158,544	$ 74,970	$ 42,279	$ 129,019	$ 404,812

Corporate Guarantees

The Board of Directors has authorized the Company to issue corporate guarantees securing obligations of our subsidiaries and to obtain letters of credit securing our subsidiaries' obligations. The maximum authorized liability under such guarantees and letters of credit during 2018 was $95.0 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily PESCO. These corporate guarantees provide for the payment of natural gas purchases in the event that PESCO defaults. PESCO has never defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at December 31, 2018 was $76.5 million, with the guarantees expiring on various dates through December 2019.

Chesapeake Utilities also guarantees the payment of FPU's first mortgage bonds. The maximum exposure under this guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU's first mortgage bonds approximate their carrying values (see Note 13, *Long-Term Debt*, for further details).

As of December 31, 2018, we have issued letters of credit totaling approximately $7.0 million related to the electric transmission services for FPU's electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, the payment of natural gas purchases for PESCO, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through December 2019. There have been no draws on these letters of credit as of December 31, 2018. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

Notes to the Consolidated Financial Statements

22. QUARTERLY FINANCIAL DATA (UNAUDITED)

In our opinion, the quarterly financial information shown below includes all adjustments necessary for a fair presentation of the operations for such periods. Due to the seasonal nature of our business, there are substantial variations in operations reported on a quarterly basis.

	For the Quarters Ended			
(in thousands except per share amounts)	March 31	June 30	September 30	December 31
2018 [1]				
Operating Revenues	$ 239,356	$ 136,664	$ 140,279	$ 201,190
Operating Income	$ 40,406	$ 13,248	$ 12,036	$ 28,930
Net Income	$ 26,855	$ 6,387	$ 5,538	$ 17,801
Earnings per share:				
Basic	$ 1.64	$ 0.39	$ 0.34	$ 1.09
Diluted	$ 1.64	$ 0.39	$ 0.34	$ 1.08
2017 [1]				
Operating Revenues	$ 185,160	$ 125,084	$ 126,936	$ 180,403
Operating Income	$ 35,099	$ 14,061	$ 14,632	$ 23,628
Net Income	$ 19,144	$ 6,046	$ 6,833	$ 26,101
Earnings per share:				
Basic	$ 1.17	$ 0.37	$ 0.42	$ 1.60
Diluted	$ 1.17	$ 0.37	$ 0.42	$ 1.59

[1] The sum of the four quarters does not equal the total for the year due to rounding.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer, with the participation of other Company officials, have evaluated our "disclosure controls and procedures" (as such term is defined under Rule 13a-15(e) and Rule 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended) as of December 31, 2018. Based upon their evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2018.

CHANGE IN INTERNAL CONTROLS

There has been no change in internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2018, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

CEO AND CFO CERTIFICATIONS

Our Chief Executive Officer and Chief Financial Officer have filed with the SEC the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the fiscal year ended December 31, 2018. In addition, on June 8, 2018, our former Chief Executive Officer certified to the NYSE that he was not aware of any violation by us of the NYSE corporate governance listing standards.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Exchange Act. A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records which in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, our management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria established in an updated report entitled "Internal Control - Integrated Framework," issued in May 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management has evaluated and concluded that our internal control over financial reporting was effective as of December 31, 2018.

Our independent auditors, Baker Tilly Virchow Krause, LLP, have audited the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their report which appears under Part II, *Item 8. Financial Statements and Supplementary Data.*

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE.

In December 2018, the Company announced that its Board of Directors had appointed Jeffry M. Householder, formerly President of the Company's Florida business unit, President and Chief Executive Officer. Concurrent with his promotion, Mr. Householder was also appointed to the Company's Board of Directors. Both appointments were effective on January 1, 2019.

The Company's former President and Chief Executive Officer, Michael P. McMasters, who retired on December 31, 2018, is continuing as a member of the Company's Board of Directors.

We have adopted a Code of Ethics that applies to our principal executive officer, president, principal financial officer, principal accounting officer or controller, and persons performing similar functions, which is a "code of ethics" as defined by applicable rules of the SEC. This Code of Ethics is publicly available on our website at http://www.chpk.com/wp-content/uploads/Code_of_Ethics.pdf. If we make any amendments to this code other than technical, administrative or other non-substantive amendments, or grant any waivers, including implicit waivers, from a provision of this code to our principal executive officer, president, principal financial officer, principal accounting officer or controller, we intend to disclose the nature of the amendment or waiver, its effective date and to whom it applies by posting such information on our website at the address and location specified above.

The remaining information required by this Item is incorporated herein by reference to the sections of our Proxy Statement captioned "Election of Directors (Proposal 1)," "Overview," "Corporate Governance," "Board of Directors and its Committees" and "Section 16(a) Beneficial Ownership Reporting Compliance."

ITEM 11. EXECUTIVE COMPENSATION.

The information required by this Item is incorporated herein by reference to the sections of our Proxy Statement captioned "Director Compensation," "Executive Compensation" and "Compensation Discussion and Analysis" in the Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by this Item is incorporated herein by reference to the sections of our Proxy Statement captioned "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by this Item is incorporated herein by reference to the section of our Proxy Statement captioned "Corporate Governance."

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement captioned "Fees and Services of Independent Registered Public Accounting Firm."

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this report:

(a)(1) All of the financial statements, reports and notes to the financial statements included in Item 8 of Part II of this Annual Report on Form 10-K.

(a)(2) Schedule II—Valuation and Qualifying Accounts.

(a)(3) The Exhibits below.

• Exhibit 3.1	Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q for the period ended June 30, 2010, File No. 001-11590.
• Exhibit 3.2	Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 4, 2012, are incorporated herein by reference to Exhibit 3 of our Current Report on Form 8-K, filed December 7, 2012, File No. 001-11590.
• Exhibit 3.3	First Amendment to the Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 3, 2014, is incorporated herein by reference to Exhibit 3.3 of our Annual Report on Form 10-K for the year ended December 31, 2014.
• Exhibit 3.4	Second Amendment to the Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective November 2, 2016, is incorporated herein by reference to Exhibit 3.3 of our Quarterly Report on Form 10-Q for the quarter ended September 30, 2016, File No. 001-11590.
• Exhibit 3.5	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed May 9, 2017, File No. 001-11590.
• Exhibit 3.6	Certificate of Elimination of Series A Participating Cumulative Preferred Stock of Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 3.6 to our Annual Report on Form 10-K for the year ended December 31, 2017, File No. 001-11590.
• Exhibit 4.1	Note Agreement dated October 18, 2005, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management, Inc., relating to the private placement of Chesapeake Utilities Corporation's 5.5% Senior Notes due 2020, is incorporated herein by reference to Exhibit 4.1 of our Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-11590.
• Exhibit 4.2	Note Agreement dated October 31, 2008, among Chesapeake Utilities Corporation, as issuer, General American Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 5.93% Senior Notes due 2023.†
• Exhibit 4.3	Note Agreement dated June 29, 2010, among Chesapeake Utilities Corporation, as issuer, Metropolitan Life Insurance Company and New England Life Insurance Company, relating to the private placement of Chesapeake Utilities Corporation's 5.68% Senior Notes due 2026 and Chesapeake Utilities Corporation's 6.43% Senior Notes due 2028.†
• Exhibit 4.4	Note Agreement dated September 5, 2013, among Chesapeake Utilities Corporation, as issuer, and certain note holders, relating to the private placement of Chesapeake Utilities Corporation's 3.73% Senior Notes due 2028 and Chesapeake Utilities Corporation's 3.88% Senior Notes due 2029.†
• Exhibit 4.5	Form of Indenture of Mortgage and Deed of Trust dated September 1, 1942, between Florida Public Utilities Company and the trustee, for the First Mortgage Bonds, is incorporated herein by reference to Exhibit 7-A of Florida Public Utilities Company's Registration No. 2-6087.

• Exhibit 4.6	Seventeenth Supplemental Indenture dated April 12, 2011, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guarantees the payment and performance obligations of Florida Public Utilities Company under the Indenture, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, File No. 001-11590.
• Exhibit 4.7	Sixteenth Supplemental Indenture dated December 1, 2009, between Chesapeake Utilities Corporation and Florida Public Utilities Company, pursuant to which Chesapeake Utilities Corporation guaranteed the secured First Mortgage Bonds of Florida Public Utilities Company under the Merger Agreement, is incorporated herein by reference to Exhibit 4.9 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
• Exhibit 4.8	Thirteenth Supplemental Indenture dated June 1, 1992, pursuant to which Florida Public Utilities, on May 1, 1992, privately placed $8,000,000 of its 9.08% First Mortgage Bonds due 2022, is incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 1992.
• Exhibit 4.9	Private Shelf Agreement dated October 8, 2015, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management Inc., relating to the private placement of Chesapeake Utilities Corporation's 3.25% Senior Notes due 2032 and the sale of other Chesapeake Utilities Corporation unsecured Senior Notes from time to time, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2015, File No. 001-11590.
• Exhibit 4.10	First Amendment to Private Shelf Agreement dated September 14, 2018, between Chesapeake Utilities Corporation, as issuer, and PGIM, Inc. (formerly known as Prudential Investment Management, Inc.), and other purchasers that may become party thereto. †
• Exhibit 4.11	Master Note Agreement dated March 2, 2017, among Chesapeake Utilities Corporation, as issuer, NYL Investors LLC, and other certain note holders that may become party thereto from time to time relating to the private placement of Chesapeake Utilities Corporation's 3.48% Senior Notes due 2038 and Chesapeake Utilities Corporation's 3.58% Senior Notes due 2038. †
• Exhibit 10.1*	Chesapeake Utilities Corporation Cash Bonus Incentive Plan, effective January 1, 2015, is incorporated herein by reference to our Proxy Statement dated March 31, 2015, in connection with our Annual Meeting held on May 6, 2015, File No. 001-11590.
• Exhibit 10.2*	Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan, effective May 2, 2013 is incorporated herein by reference to our Proxy Statement dated March 29, 2013 in connection with our Annual Meeting held on May 2, 2013, File No. 001-11590.
• Exhibit 10.3*	Non-Qualified Deferred Compensation Plan, effective January 1, 2014, is incorporated herein by reference to Exhibit 10.8 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
• Exhibit 10.4*	Executive Employment Agreement dated January 14, 2011, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
• Exhibit 10.5*	Amendment to Executive Employment Agreement effective January 1, 2014, between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K filed January 14, 2014, File No. 001-11590.
• Exhibit 10.6*	Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.9 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.7*	Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.10 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.
• Exhibit 10.8*	Executive Employment Agreement dated January 9, 2013, between Chesapeake Utilities Corporation and Elaine B. Bittner, incorporated herein by reference to Exhibit 10.11 of our Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-11590.

• Exhibit 10.9*	Executive Employment Agreement dated January 1, 2015, between Chesapeake Utilities Corporation and Jeffry M. Householder, is incorporated herein by reference to Exhibit 10.15 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
• Exhibit 10.10*	Form of Performance Share Agreement, effective January 7, 2014 for the period 2014 to 2016, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, and Jeffry M. Householder is incorporated herein by reference to Exhibit 10.18 of our Annual Report on Form 10-K for the year ended December 31, 2013, File No. 001-11590.
• Exhibit 10.11*	Form of Performance Share Agreement, effective January 13, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner and Jeffry M. Householder, is incorporated herein by reference to Exhibit 10.19 of our Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-11590.
• Exhibit 10.12*	Form of Performance Share Agreement, dated March 6, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and James F. Moriarty is incorporated herein by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the year ended September 30, 2015, File No. 001-11590.
• Exhibit 10.13*	Form of Performance Share Agreement, dated January 12, 2016 for the period 2016 to 2018, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder and James F. Moriarty, is incorporated herein by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2015, File No. 001-11590.
• Exhibit 10.14*	Chesapeake Utilities Corporation Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.27 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
• Exhibit 10.15*	First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Plan as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.30 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
• Exhibit 10.16	Revolving Credit Agreement dated October 8, 2015, between Chesapeake Utilities Corporation and PNC Bank, National Association, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada and Wells Fargo Bank, National Association as lenders, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2015, File No. 001-11590.
• Exhibit 10.17	First Amendment dated February 25, 2016 to the Revolving Credit Agreement dated October 8, 2015, between Chesapeake Utilities Corporation and PNC Bank, National Association, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada and Wells Fargo Bank, National Association as lenders, is incorporated herein by reference to Exhibit 10.24 of our Annual Report on Form 10-K for the year ended December 31, 2015, File No. 001-11590.
• Exhibit 10.18*	Executive Employment Agreement dated May 10, 2016, between Chesapeake Utilities Corporation and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the year ended June 30, 2016, File No. 001-11590.
• Exhibit 10.19*	Form of Performance Share Agreement, effective February 23, 2017 for the period 2017 to 2019, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder, and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the year ended June 30, 2017, File No. 001-11590.
• Exhibit 10.20	Credit Agreement, dated November 28, 2017, by and between Chesapeake Utilities Corporation and Branch Banking and Trust Company is filed herewith.

• Exhibit 10.21*	Separation Agreement and Release, effective as of June 7, 2018, by and between Chesapeake Utilities Corporation and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on June 8, 2018, File No. 001-11590.
• Exhibit 10.22*	Form of Performance Share Agreement, effective February 26, 2018 for the period 2018 to 2020, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Jeffry M. Householder and James F. Moriarty, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, File No. 001-11590.
• Exhibit 10.23	Term Note dated December 21, 2018 issued by Chesapeake Utilities Corporation in favor of PNC Bank, National Association is filed herewith.
• Exhibit 10.24*	Form of Performance Share Agreement, effective February 25, 2019 for the period January 01, 2019 to December 31, 2021, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and Jeffry M. Householder is filed herewith.
• Exhibit 10.25*	Executive Employment Agreement dated February 25, 2019, between Chesapeake Utilities Corporation and Jeffry M. Householder, is filed herewith.
• Exhibit 10.26	Term Note dated January 31, 2019 issued by Chesapeake Utilities Corporation in favor of Branch Banking & Trust Company is filed herewith.
• Exhibit 21	Subsidiaries of the Registrant is filed herewith.
• Exhibit 23.1	Consent of Independent Registered Public Accounting Firm is filed herewith.
• Exhibit 31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), is filed herewith.
• Exhibit 31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d – 14(a), is filed herewith.
• Exhibit 32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, is filed herewith.
• Exhibit 32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, is filed herewith.

- Exhibit 101.INS XBRL Instance Document is filed herewith.
- Exhibit 101.SCH XBRL Taxonomy Extension Schema Document is filed herewith.
- Exhibit 101.CAL XBRL Taxonomy Extension Calculation Linkbase Document is filed herewith.
- Exhibit 101.DEF XBRL Taxonomy Extension Definition Linkbase Document is filed herewith.
- Exhibit 101.LAB XBRL Taxonomy Extension Label Linkbase Document is filed herewith.
- Exhibit 101.PRE XBRL Taxonomy Extension Presentation Linkbase Document is filed herewith.

* Management contract or compensatory plan or agreement.

† These agreements have not been filed herewith pursuant to Item 601(b)(4)(v) of Regulation S-K under the Securities Act of 1933, as amended. We hereby agree to furnish copies to the SEC upon request.

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, Chesapeake Utilities Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

By: /s/ JEFFRY M. HOUSEHOLDER
Jeffry M. Householder
President, Chief Executive Officer and Director
February 26, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ JEFFRY M. HOUSEHOLDER
Jeffry M. Householder
President, Chief Executive Officer and Director
February 26, 2019

/s/ BETH W. COOPER
Beth W. Cooper, Executive Vice President,
Chief Financial Officer,
and Assistant Corporate Secretary
(Principal Financial and Accounting Officer)
February 26, 2019

/s/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Chair of the Board and Director
February 26, 2019

/s/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
February 26, 2019

/s/ EUGENE H. BAYARD, ESQ
Eugene H. Bayard, Esq., Director
February 26, 2019

/s/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
February 26, 2019

/s/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
February 26, 2019

/s/ MICHAEL P. MCMASTERS
Michael P. McMasters, Director
February 26, 2019

/s/ RONALD G. FORSYTHE, JR.
Dr. Ronald G. Forsythe, Jr., Director
February 26, 2019

/s/ CALVERT A. MORGAN, JR.
Calvert A. Morgan, Jr., Director
February 26, 2019

/s/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
February 26, 2019

/s/ DIANNA F. MORGAN
Dianna F. Morgan, Director
February 26, 2019

Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions: Charged to Income	Additions: Other Accounts [1]	Deductions [2]	Balance at End of Year
(In thousands)					
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
2018	**$ 936**	**$ 1,157**	**$ 136**	**$ (1,121)**	**$ 1,108**
2017	909	602	337	(912)	936
2016	909	985	340	(1,325)	909

[1] Recoveries.
[2] Uncollectible accounts charged off.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended: March 31, 2019

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission File Number: 001-11590

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CHESAPEAKE UTILITIES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	51-0064146
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including Zip Code)

(302) 734-6799
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock - par value per share $0.4867	CPK	New York Stock Exchange, Inc.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Common Stock, par value $0.4867 — 16,397,017 shares outstanding as of April 30, 2019.

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GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification issued by the FASB

ASU: Accounting Standards Update issued by the FASB

CDD: Cooling 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 above 65 degrees Fahrenheit

Chesapeake or Chesapeake Utilities: Chesapeake Utilities Corporation, and its direct and indirect subsidiaries, as appropriate in the context of the disclosure

CHP: Combined heat and power plant

Company: Chesapeake Utilities Corporation, and its direct and indirect subsidiaries, as appropriate in the context of the disclosure

Degree-Day: A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am) falls above or below 65 degrees Fahrenheit

Delmarva Peninsula: A peninsula on the east coast of the U. S. occupied by Delaware and portions of Maryland and Virginia

Dt(s): Dekatherm(s), which is a natural gas unit of measurement that includes a standard measure for heating value

Dts/d: Dekatherms per day

Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned subsidiary of Chesapeake Utilities

Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake OnSight Services, LLC

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake Utilities

GAAP: Accounting principles generally accepted in the United States of America

GRIP: Gas Reliability Infrastructure Program

Gross Margin: a non-GAAP measure defined as operating revenues less the cost of sales. The Company's cost of sales includes purchased fuel cost for natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities and excludes depreciation, amortization and accretion

Gulfstream: Gulfstream Natural Gas System, LLC, an unaffiliated pipeline network that supplies natural gas to FPU

HDD: Heating Degree-Day

Marlin Gas Services: Marlin Gas Services, LLC, a newly created subsidiary of Chesapeake Utilities that acquired certain operating assets of Marlin Gas Transport, Inc.

Marlin Gas Transport: Marlin Gas Transport, Inc., a supplier of mobile compressed natural gas utility and pipeline solutions

MetLife: MetLife Investment Advisors, an institutional debt investment management firm, with which we entered into the MetLife Shelf Agreement

MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use

MTM: Mark-to-Market (fair value accounting)

NYL: New York Life Investors LLC, an institutional debt investment management firm, with which Chesapeake Utilities entered into a Shelf Agreement

Peninsula Pipeline: Peninsula Pipeline Company, Inc., a wholly-owned subsidiary of Chesapeake Utilities

PESCO: Peninsula Energy Services Company, Inc., a wholly-owned subsidiary of Chesapeake Utilities

Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which Chesapeake Utilities has entered into a Shelf Agreement and issued Shelf Notes

PSC: Public Service Commission, which is the state agency that regulates utility rates and/or services in certain of our jurisdictions

Retirement Savings Plan: A qualified 401(k) retirement savings plan sponsored by Chesapeake Utilities

Revolver: Our unsecured revolving credit facility with certain lenders

Sandpiper: Sandpiper Energy, Inc., a wholly-owned subsidiary of Chesapeake Utilities

SEC: U.S. Securities and Exchange Commission

Senior Notes: Our unsecured long-term debt issued primarily to insurance companies on various dates

Sharp: Sharp Energy, Inc., a wholly-owned subsidiary of Chesapeake Utilities

Shelf Agreement: An agreement entered into by Chesapeake Utilities and a counterparty pursuant to which Chesapeake Utilities may request that the counterparty purchase our unsecured senior debt with a fixed interest rate and a maturity date not to exceed 20 years from the date of issuance

Shelf Notes: Unsecured senior promissory notes issuable under the Shelf Agreement executed with various counterparties

SICP: 2013 Stock and Incentive Compensation Plan

TCJA: Tax Cuts and Jobs Act enacted on December 22, 2017

TETLP: Texas Eastern Transmission, LP, an interstate pipeline interconnected with Eastern Shore's pipeline

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

(in thousands, except shares and per share data)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Operating Revenues		
Regulated Energy	$ 103,618	$ 109,393
Unregulated Energy and other	123,998	129,963
Total Operating Revenues	227,616	239,356
Operating Expenses		
Regulated Energy cost of sales	36,516	48,231
Unregulated Energy and other cost of sales	89,703	99,826
Operations	37,144	32,702
Maintenance	3,681	3,593
Depreciation and amortization	11,074	9,704
Other taxes	5,505	4,894
Total Operating Expenses	183,623	198,950
Operating Income	43,993	40,406
Other income (expense), net	(45)	68
Interest charges	5,710	3,664
Income Before Income Taxes	38,238	36,810
Income taxes	9,574	9,955
Net Income	$ 28,664	$ 26,855
Weighted Average Common Shares Outstanding:		
Basic	16,384,927	16,351,338
Diluted	*16,432,852*	*16,402,985*
Earnings Per Share of Common Stock:		
Basic	$ 1.75	$ 1.64
Diluted	$ 1.74	$ 1.64

The accompanying notes are an integral part of these financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Comprehensive Income (Unaudited)

(in thousands)	Three Months Ended March 31, 2019	2018
Net Income	**$ 28,664**	$ 26,855
Other Comprehensive Income (Loss), net of tax:		
Employee Benefits, net of tax:		
Amortization of prior service cost, net of tax of $(5) and $(5), respectively	**(14)**	(14)
Net gain, net of tax of $42 and $41, respectively	**121**	108
Cash Flow Hedges, net of tax:		
Unrealized gain (loss) on commodity contract cash flow hedges, net of tax of $1,194 and $(756), respectively	**2,982**	(1,788)
Total Other Comprehensive Income (Loss), net of tax	**3,089**	(1,694)
Comprehensive Income	**$ 31,753**	$ 25,161

The accompanying notes are an integral part of these financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Assets *(in thousands, except shares and per share data)*	March 31, 2019	December 31, 2018
Property, Plant and Equipment		
Regulated Energy	$ 1,346,221	$ 1,297,416
Unregulated Energy	241,126	237,682
Other businesses and eliminations	30,282	34,585
Total property, plant and equipment	1,617,629	1,569,683
Less: Accumulated depreciation and amortization	(312,949)	(294,295)
Plus: Construction work in progress	90,453	108,584
Net property, plant and equipment	1,395,133	1,383,972
Current Assets		
Cash and cash equivalents	7,975	6,089
Trade and other receivables (less allowance for uncollectible accounts of $1,054 and $1,108, respectively)	74,098	85,404
Accrued revenue	20,747	27,499
Propane inventory, at average cost	6,865	9,791
Other inventory, at average cost	8,122	7,127
Regulatory assets	7,913	4,796
Storage gas prepayments	1,327	6,603
Income taxes receivable	9,059	15,300
Prepaid expenses	7,192	10,079
Derivative assets, at fair value	9,221	13,165
Other current assets	1,121	5,684
Total current assets	153,640	191,537
Deferred Charges and Other Assets		
Goodwill	25,785	25,837
Other intangible assets, net	5,909	6,207
Investments, at fair value	7,509	6,711
Operating lease right-of-use assets (refer to Note 15)	12,523	—
Regulatory assets	77,101	72,422
Other assets	5,197	6,985
Total deferred charges and other assets	134,024	118,162
Total Assets	$ 1,682,797	$ 1,693,671

The accompanying notes are an integral part of these financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities *(in thousands, except shares and per share data)*	March 31, 2019	December 31, 2018
Capitalization		
Stockholders' equity		
Preferred stock, par value $0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	$ —	$ —
Common stock, par value $0.4867 per share (authorized 50,000,000 shares)	7,980	7,971
Additional paid-in capital	255,307	255,651
Retained earnings	284,111	261,530
Accumulated other comprehensive loss	(3,739)	(6,713)
Deferred compensation obligation	4,376	3,854
Treasury stock	(4,376)	(3,854)
Total stockholders' equity	543,659	518,439
Long-term debt, net of current maturities	285,998	316,020
Total capitalization	829,657	834,459
Current Liabilities		
Current portion of long-term debt	71,509	11,935
Short-term borrowing	276,393	294,458
Accounts payable	75,277	129,804
Customer deposits and refunds	29,710	34,155
Accrued interest	4,505	2,317
Dividends payable	6,067	6,060
Accrued compensation	8,506	13,923
Regulatory liabilities	15,085	7,883
Derivative liabilities, at fair value	6,798	14,871
Other accrued liabilities	14,719	12,828
Total current liabilities	508,569	528,234
Deferred Credits and Other Liabilities		
Deferred income taxes	160,912	156,820
Regulatory liabilities	132,686	135,039
Environmental liabilities	7,370	7,638
Other pension and benefit costs	29,822	28,513
Operating lease - liabilities (refer to Note 15)	10,873	—
Deferred investment tax credits and other liabilities	2,908	2,968
Total deferred credits and other liabilities	344,571	330,978
Environmental and other commitments and contingencies (Notes 5 and 6)		
Total Capitalization and Liabilities	$ 1,682,797	$ 1,693,671

The accompanying notes are an integral part of these financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Three Months Ended March 31,	
	2019	2018
(in thousands)		
Operating Activities		
Net income	$ 28,664	$ 26,855
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	11,074	9,704
Depreciation and accretion included in other costs	2,135	2,276
Deferred income taxes	3,430	6,469
Realized (gain) loss on commodity contracts/sale of assets/investments	(363)	3,416
Unrealized (gain) loss on investments/commodity contracts	(721)	44
Employee benefits and compensation	382	228
Share-based compensation	487	1,520
Other, net	—	(12)
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	18,147	9,649
Propane inventory, storage gas and other inventory	7,207	12,448
Regulatory assets/liabilities, net	3,121	11,511
Prepaid expenses and other current assets	11,873	8,095
Accounts payable and other accrued liabilities	(44,783)	(26,932)
Income taxes receivable	6,241	8,741
Customer deposits and refunds	(4,445)	44
Accrued compensation	(5,548)	(7,731)
Other assets and liabilities, net	3,585	347
Net cash provided by operating activities	40,486	66,672
Investing Activities		
Property, plant and equipment expenditures	(43,216)	(63,116)
Proceeds from sales of assets	115	193
Environmental expenditures	(268)	(48)
Net cash used in investing activities	(43,369)	(62,971)
Financing Activities		
Common stock dividends	(5,877)	(5,147)
Issuance of stock under the Dividend Reinvestment Plan	(183)	(164)
Tax withholding payments related to net settled stock compensation	(692)	(719)
Change in cash overdrafts due to outstanding checks	84	2,352
Net repayment under line of credit agreements	(18,149)	(24,213)
Proceeds from long-term debt	30,000	25,000
Repayment of long-term debt, long-term borrowing under the Revolver and capital lease obligation	(414)	(428)
Net cash provided (used) by financing activities	4,769	(3,319)
Net Increase in Cash and Cash Equivalents	1,886	382
Cash and Cash Equivalents—Beginning of Period	6,089	5,614
Cash and Cash Equivalents—End of Period	$ 7,975	$ 5,996

The accompanying notes are an integral part of these financial statements.

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

(in thousands, except shares and per share data)	Common Stock [1] Number of Shares[2]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2017	**16,344,442**	**$ 7,955**	**$ 253,470**	**$ 229,141**	**$ (4,272)**	**$ 3,395**	**$ (3,395)**	**$ 486,294**
Net income	—	—	—	26,855	—	—	—	26,855
Cumulative effect of the adoption of ASU 2014-09	—	—	—	(1,498)	—	—	—	(1,498)
Reclassification upon the adoption of ASU 2018-02	—	—	—	907	(907)	—	—	—
Other comprehensive loss	—	—	—	—	(1,694)	—	—	(1,694)
Dividend declared ($.3250 per share)	—	—	—	(5,381)	—	—	—	(5,381)
Dividend reinvestment plan	—	—	(1)	—	—	—	—	(1)
Share-based compensation and tax benefit [3][4]	19,350	9	657	—	—	—	—	666
Treasury stock activities	—	—	—	—	—	178	(178)	—
Balance at March 31, 2018	**16,363,792**	**$ 7,964**	**$ 254,126**	**$ 250,024**	**$ (6,873)**	**$ 3,573**	**$ (3,573)**	**$ 505,241**
Balance at December 31, 2018	**16,378,545**	**$ 7,971**	**$ 255,651**	**$ 261,530**	**$ (6,713)**	**$ 3,854**	**$ (3,854)**	**$ 518,439**
Net income	—	—	—	28,664	—	—	—	28,664
Prior period reclassification	—	—	—	115	(115)	—	—	—
Other comprehensive income	—	—	—	—	3,089	—	—	3,089
Dividend declared ($0.3700 per share)	—	—	—	(6,198)	—	—	—	(6,198)
Dividend reinvestment plan	—	—	(1)	—	—	—	—	(1)
Share-based compensation and tax benefit [3] [4]	18,472	9	(343)	—	—	—	—	(334)
Treasury stock activities	—	—	—	—	—	522	(522)	—
Balance at March 31, 2019	**16,397,017**	**$ 7,980**	**$ 255,307**	**$ 284,111**	**$ (3,739)**	**$ 4,376**	**$ (4,376)**	**$ 543,659**

(1) 2,000,000 shares of preferred stock at $0.01 par value have been authorized. None has been issued or is outstanding; accordingly, no information has been included in the statements of stockholders' equity.

(2) Includes 101,997 shares at March 31, 2019, 97,053 shares at December 31, 2018, 93,422 shares at March 31, 2018 and 90,961 shares at December 31, 2017, respectively, held in a Rabbi Trust related to our Non-Qualified Deferred Compensation Plan.

(3) Includes amounts for shares issued for directors' compensation.

(4) The shares issued under the SICP are net of shares withheld for employee taxes. For the three months ended March 31, 2019 and 2018, we withheld 7,635 and 10,436 shares, respectively, for taxes.

The accompanying notes are an integral part of these financial statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Summary of Accounting Policies

Basis of Presentation

References in this document to the "Company," "Chesapeake Utilities," "we," "us" and "our" are intended to mean Chesapeake Utilities Corporation, its divisions and/or its subsidiaries, as appropriate in the context of the disclosure.

The accompanying unaudited condensed consolidated financial statements have been prepared in compliance with the rules and regulations of the SEC and GAAP. In accordance with these rules and regulations, certain information and disclosures normally required for audited financial statements have been condensed or omitted. These financial statements should be read in conjunction with the consolidated financial statements and notes thereto, included in our latest Annual Report on Form 10-K for the year ended December 31, 2018. In the opinion of management, these financial statements reflect normal recurring adjustments that are necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods presented.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is highest due to colder temperatures.

Marlin Gas Transport and Ohl Fuel Oil Acquisitions

In December 2018, Marlin Gas Services acquired certain operating assets of Marlin Gas Transport. The acquisition will enable us to offer solutions to supply interruption scenarios and tailor other alternatives where pipeline supplies are unavailable or inadequate to meet customer requirements.

In December 2018, Sharp acquired certain propane operating assets and customers of R. F. Ohl Fuel Oil, Inc. ("Ohl"), which provided propane distribution service to approximately 2,500 residential and commercial customers in Pennsylvania.

We accounted for the purchases of the operating assets of Marlin Gas Transport and Ohl, which totaled approximately $18.4 million, as business combinations within our Unregulated Energy segment. Goodwill of $4.8 million, related to the Marlin Gas Transport acquisition, and $1.5 million, associated with the Ohl acquisition, were initially recorded at the close of these transactions. The amounts recorded in conjunction with these acquisitions are preliminary and subject to adjustment based on additional valuations performed during the measurement period. Due to the timing of these acquisitions, the revenue and net income from these acquisitions in 2018 were immaterial. For the quarter ended March 31, 2019, these acquisitions generated the following operating revenue and income:

	Three Months Ended March 31, 2019	
	Operating Revenue	Operating Income
(in thousands)		
Marlin Gas Services	$ 2,434	$ 1,375
Ohl	$ 822	$ 273

FASB Statements and Other Authoritative Pronouncements

Recently Adopted Accounting Standards

Leases (ASC 842) - In February 2016, the FASB issued ASU 2016-02, *Leases,* which requires lessees to recognize leases on the balance sheet and disclose key information about leasing arrangements. The standard establishes a right of use model that requires a lessee to recognize a right of use asset and lease liability for all leases with a term greater than 12 months. The update also expands the required quantitative and qualitative disclosures surrounding leases. ASC 842 was subsequently amended by ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*; ASU No. 2018-10, *Codification Improvements to Topic 842, Leases*; ASU No. 2018-11, *Targeted Improvements*; and ASU No. 2019-01, *Codification Improvements*. We adopted ASU 2016-02 and the related amendments on January 1, 2019, and used the optional transition method for all existing leases. The optional transition method enables us to adopt the new standard as of the beginning of the period of adoption and does not require restatement of prior period financial information. As a result, prior period financial information has not been recast and continues to be reported under the accounting guidance that was effective during those periods.

At adoption, we elected the following practical expedients: (1) the 'package of practical expedients,' pursuant to which we did not need to reassess our prior conclusions about lease identification, lease classification and initial direct costs, (2) the 'use-of-hindsight' practical expedient, which allowed us to use hindsight in assessing impairment of our existing land easements, (3) creation of an accounting policy for short-term leases resulting in lease payments being recorded as an expense on a straight-line basis over the lease term, and (4) to not separate lease and non-lease components for all leases.

See Note 15, *Leases,* for additional information with respect to the impact of the adoption of the lease accounting guidance and the disclosures required by ASU 2016-02 and the related amendments.

Compensation - Stock Compensation (ASC 718) - In June 2018, the FASB issued ASU 2018-07, *Improvements to Nonemployee Share-Based Payment Accounting*, which expands the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees. We adopted ASU 2018-07 on January 1, 2019. Implementation of this new standard did not have a material impact on our financial position or results of operations.

Recent Accounting Standards Yet to be Adopted

Intangibles-Goodwill (ASC 350) - In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment*, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. ASU 2017-04 will be effective for our annual and interim financial statements beginning January 1, 2020, although early adoption is permitted. The amendments included in this ASU are to be applied prospectively. We believe that implementation of this new standard will not have a material impact on our financial position or results of operations.

Fair Value Measurement (ASC 820) - In August 2018, the FASB issued ASU 2018-13, *Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement*, which removes, modifies and adds certain disclosure requirements on fair value measurements in ASC 820. ASU 2018-13 will be effective for our annual and interim financial statements beginning January 1, 2020 and, since the changes only impact disclosures, will not have a material impact on our financial position or results of operations.

2. Calculation of Earnings Per Share

(in thousands, except shares and per share data)	Three Months Ended March 31, 2019	2018
Calculation of Basic Earnings Per Share:		
Net Income	**$ 28,664**	$ 26,855
Weighted average shares outstanding	**16,384,927**	16,351,338
Basic Earnings Per Share	**$ 1.75**	$ 1.64
Calculation of Diluted Earnings Per Share:		
Reconciliation of Numerator:		
Net Income	**$ 28,664**	$ 26,855
Reconciliation of Denominator:		
Weighted shares outstanding—Basic	**16,384,927**	16,351,338
Effect of dilutive securities—Share-based compensation	**47,925**	51,647
Adjusted denominator—Diluted	**16,432,852**	16,402,985
Diluted Earnings Per Share	**$ 1.74**	$ 1.64

3. Revenue Recognition

We recognize revenue when our performance obligations under contracts with customers have been satisfied, which generally occurs when our businesses have delivered or transported natural gas, electricity or propane to customers. We exclude sales taxes and other similar taxes from the transaction price. Typically, our customers pay for the goods and/or services we provide in the month following the satisfaction of our performance obligation.

The following table displays our revenue by major source based on product and service type for the three months ended March 31, 2019 and 2018:

	Three months ended March 31, 2019				Three Months Ended March 31, 2018			
(in thousands)	Regulated Energy	Unregulated Energy	Other and Eliminations	Total	Regulated Energy	Unregulated Energy	Other and Eliminations	Total
Energy distribution								
Delaware natural gas division	$ 27,549	$ —	$ —	$ 27,549	$ 32,072	$ —	$ —	$ 32,072
Florida natural gas division	7,900	—	—	7,900	5,864	—	—	5,864
FPU electric distribution	14,378	—	—	14,378	18,741	—	—	18,741
FPU natural gas distribution	23,786	—	—	23,786	23,213	—	—	23,213
Maryland natural gas division	10,047	—	—	10,047	10,672	—	—	10,672
Sandpiper natural gas/propane operations	7,082	—	—	7,082	8,964	—	—	8,964
Total energy distribution	90,742	—	—	90,742	99,526	—	—	99,526
Energy transmission								
Aspire Energy	—	13,470	—	13,470	—	12,077	—	12,077
Eastern Shore	19,056	—	—	19,056	15,597	—	—	15,597
Peninsula Pipeline	3,565	—	—	3,565	2,098	—	—	2,098
Total energy transmission	22,621	13,470	—	36,091	17,695	12,077	—	29,772
Energy generation								
Eight Flags	—	4,142	—	4,142	—	4,378	—	4,378
Propane operations								
Propane delivery operations	—	46,125	—	46,125	—	52,104	—	52,104
Energy services								
Marlin Gas Services	—	2,434	—	2,434	—	—	—	—
PESCO - Natural Gas Marketing	—	77,022	—	77,022		81,559	—	81,559
Total energy services	—	79,456	—	79,456	—	81,559	—	81,559
Other and eliminations								
Eliminations	(9,745)	(5,496)	(14,236)	(29,477)	(7,828)	(5,245)	(15,598)	(28,671)
Other	—	405	132	537	—	494	194	688
Total other and eliminations	(9,745)	(5,091)	(14,104)	(28,940)	(7,828)	(4,751)	(15,404)	(27,983)
Total operating revenues[1]	$ 103,618	$ 138,102	$ (14,104)	$227,616	$ 109,393	$ 145,367	$ (15,404)	$239,356

(1) Total operating revenues for the three months ended March 31, 2019, include other revenue (revenues from sources other than contracts with customers) of $121,000 and $84,000 for our Regulated and Unregulated Energy segments, respectively and $(589,000) and $73,000 for our Regulated and Unregulated Energy segments, respectively, for the three months ended March 31, 2018. The sources of other revenues include revenue from alternative revenue programs related to revenue normalization for the Maryland division and Sandpiper and late fees.

Contract balances

The timing of revenue recognition, customer billings and cash collections results in trade receivables, unbilled receivables (contract assets), and customer advances (contract liabilities) in our condensed consolidated balance sheets. The balances of our trade receivables, contract assets, and contract liabilities as of December 31, 2018 and March 31, 2019 were as follows:

(in thousands)	Trade Receivables	Contract Assets (Non-current)	Contract Liabilities (Current)
Balance at 12/31/2018	$ 83,214	$ 2,614	$ 480
Balance at 3/31/2019	**72,162**	**3,004**	**305**
Increase (decrease)	$ (11,052)	$ 390	$ (175)

Our trade receivables are included in trade and other receivables in the condensed consolidated balance sheets. Our non-current contract assets are included in other assets in the condensed consolidated balance sheet and relate to operations and maintenance costs incurred by Eight Flags that have not yet been recovered through rates for the sale of electricity to our electric distribution operation pursuant to a long-term service agreement.

At times, we receive advances or deposits from our customers before we satisfy our performance obligation, resulting in contract liabilities. At March 31, 2019 and December 31, 2018, we had a contract liability of $305,000 and $480,000, respectively, which was included in other accrued liabilities in the condensed consolidated balance sheet, and which relates to non-refundable prepaid fixed fees for our Delmarva Peninsula propane delivery operation's retail offerings. Our performance obligation is satisfied over the term of the respective retail offering plan on a ratable basis. For the three months ended March 31, 2019 and 2018, we recognized revenue of $287,000 and $251,000, respectively.

Remaining performance obligations

Our businesses have long-term fixed fee contracts with customers in which revenues are recognized as performance obligations are satisfied over the contract term. Revenue for these businesses for the remaining performance obligations at March 31, 2019 are expected to be recognized as follows:

(in thousands)	2019	2020	2021	2022	2023	2024	2025 and thereafter
Eastern Shore and Peninsula Pipeline	$ 28,754	$ 36,791	$33,510	$26,566	$ 21,146	$18,969	$ 193,651
Natural gas distribution operations	2,999	3,587	3,358	3,320	2,924	2,910	27,916
PESCO - Natural Gas Marketing	4,435	4,585	1,706	22	—	—	—
FPU electric distribution	223	297	297	109	—	—	—
Total revenue contracts with remaining performance obligations	$ 36,411	$ 45,260	$38,871	$30,017	$ 24,070	$21,879	$ 221,567

4. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC.

Delaware

Effect of the TCJA on Customers: On January 31, 2019, the Delaware PSC approved the as-filed Delaware Division Delivery Service Rates reflecting the impact of the TCJA. The new rates went into effect March 1, 2019, and we will have to complete refunds retroactive to February 2018, by June 30, 2019. The order also provided for a line item billing credit that went into effect on April 1, 2019, for the return of the excess accumulated deferred income taxes ("ADIT"). Additional information on the TCJA impact is included in the table at the end of this Note 4, *Rates and Other Regulatory Activities*.

Weather Normalization Adjustment: In January 2019, we filed with the Delaware PSC an application requesting approval to implement a weather normalization adjustment. The proposed weather normalization adjustment will provide either a billing credit (during colder than normal weather) or surcharge (during warmer than normal weather) designed to produce natural gas bills for customers that reflect normal temperatures. The weather normalization adjustment will ensure we do not over or under-collect Delaware PSC authorized levels of distribution revenues due to weather variability. The Delaware PSC issued an order on March 19, 2019 to open a docket and formally review the case.

Florida

Electric Limited Proceeding-Storm Recovery: In February 2018, FPU filed a petition with the Florida PSC, requesting recovery of incremental storm restoration costs related to several hurricanes and tropical storms, along with the replenishment of the storm reserve to its pre-storm level of $1.5 million. As a result of these hurricanes and tropical storms, FPU's storm reserve was depleted and, at the time of this filing, had a deficit of $779,000. This matter went to hearing in December 2018 and was subsequently approved at the March 5, 2019 Agenda with the Final Order issued on March 25, 2019. FPU received approval to begin a surcharge of $1.54 per 1,000 kilowatt hour on customer bills for two years beginning in April 2019, to recover storm-related costs and replenish the storm reserve.

Hurricane Michael: In October 2018, Hurricane Michael passed through FPU's electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure resulting in 100 percent of its customers losing electrical service. FPU, after exerting extraordinary hurricane restoration efforts, restored service to those customers who were able to accept it. FPU expended more than $65.0 million to restore service, which has been recorded as new plant and equipment or charged against FPU's storm reserve. In conjunction with the hurricane-related expenditures, we executed two 13-month unsecured term loans as temporary financing, each in the amount of $30 million. The interest cost associated with these loans is LIBOR plus 75 points. One of the term loans was executed in December 2018; the other was executed in January 2019. While there is a short-term negative impact, the storm is not expected to have a significant impact going forward, assuming reasonable regulatory treatment. We have begun preparing the necessary regulatory filings to seek recovery of the costs incurred, including the financing costs for the temporary debt issued to fund the new plant and equipment.

Effect of the TCJA on Customers: In February 2018, the Florida PSC opened dockets to consider the impacts associated with the TCJA. In May 2018, FPU's natural gas divisions filed petitions and supporting testimony regarding the disposition of the related impacts of the TCJA. Hearings on this matter took place in November 2018, and the staff's recommendation was approved by the Florida PSC at the February 5, 2019 Agenda. Final orders were issued on February 25, 2019. Staff's recommendations are summarized in the table at the end of this Note 4, *Rates and Other Regulatory Activities.*

Imbalance Petition: In February 2019, FPU filed a petition, with the Florida PSC, to modify the pool manager cash out tiers and respective cash out rates. With this petition, FPU further facilitates consistency across the Florida business units and eliminates the unintentional arbitrage opportunity created by the tariff. The petition does not have a financial impact for FPU, and it will benefit customers by lowering costs. This petition was approved by the Florida PSC at the April 2, 2019 Agenda.

Maryland Division and Sandpiper

There were no material regulatory matters during the quarter.

Eastern Shore

Del-Mar Energy Pathway Project: In September 2018, Eastern Shore filed a Certificate Application with the FERC, requesting authorization to construct and operate the Del-Mar Energy Pathway project, which will provide an additional 14,300 Dts/d of firm service to four customers. Facilities to be constructed include six miles of pipeline looping in Delaware; 13 miles of new mainline extension in Sussex County, Delaware and Somerset County, Maryland; and new pressure control and delivery stations in these counties. The benefits of this project include: (i) additional natural gas transmission pipeline infrastructure in eastern Sussex County, Delaware, and (ii) extension of Eastern Shore's pipeline system, for the first time, into Somerset County, Maryland. During the fourth quarter of 2018, the FERC held a full project area scoping meeting in Sussex County, Delaware and issued a Notice of Schedule for Environmental Review. The Environmental Assessment for the Del-Mar Energy Pathway project was issued on April 1, 2019. As of the date of this filing, final FERC authorization was still pending.

Summary TCJA Table

The following table summarizes the TCJA impact on our regulated businesses:

	Regulatory Liabilities related to ADIT		
Operation and Regulatory Jurisdiction	**Amount (in thousands)**	**Status**	**Status of Customer Rate impact related to lower federal corporate income tax rate**
Eastern Shore (FERC)	$34,190	Will be addressed in Eastern Shore's next rate case filing	Implemented one-time bill credit (totaling $900,000) in April 2018 - Customer rates adjusted in April, 2018
Delaware Division (Delaware PSC)	$13,082	PSC approved amortization of ADIT in January 2019	Customer rates adjusted March 1, 2019. One-time bill credit to be implemented during the second quarter of 2019
Maryland Division (Maryland PSC)	$4,171	PSC approved amortization of ADIT in May 2018	Implemented one-time bill credit (totaling $365,000) in July 2018 - Customer rates adjusted effective May 1, 2018
Sandpiper Energy (Maryland PSC)	$3,803	PSC approved amortization of ADIT in May 2018	Implemented one-time bill credit (totaling $608,000) in July 2018 - Customer rates adjusted effective May 1, 2018
Chesapeake Florida Gas Division/Central Florida Gas (Florida PSC)	$8,346	PSC issued order authorizing amortization and retention of net ADIT liability by the Company on February 25, 2019	PSC Staff recommendation issued on January 24, 2019; final order was issued on February 25, 2019; No one-time bill credit or adjustment in rates will be applied; the tax savings arising from the TCJA rate reduction will be retained by the Company
FPU Natural Gas (includes FPU, Fort Meade, and Indiantown) (Florida PSC)	$19,478	Same treatment on a net basis as Chesapeake Florida Gas Division (above)	Same treatment on a net basis as Chesapeake Florida Gas Division (above)
FPU Electric (Florida PSC)	$5,950	In January 2019, PSC issued order approving amortization of ADIT through purchased power cost recovery, storm reserve and rates	TCJA benefit will flow back to its customers through a combination of reductions to the fuel cost recovery rate, base rates, as well as application to the storm reserve over the next several years

5. Environmental Commitments and Contingencies

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remediate, at current and former operating sites, the effect on the environment of the disposal or release of specified substances.

MGP Sites

We have participated in the investigation, assessment or remediation of, and have exposures at, seven former MGP sites. We have received approval for recovery of clean-up costs in rates for sites located in Salisbury, Maryland; Seaford, Delaware; and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We are also in discussions with the Maryland Department of Environment ("MDE") regarding another former MGP site located in Cambridge, Maryland.

As of March 31, 2019 and December 31, 2018, we had approximately $8.9 million and $9.1 million, respectively, in environmental liabilities related to FPU's MGP sites in Key West, Pensacola, Sanford and West Palm Beach. FPU has approval to recover, from insurance and through customer rates, up to $14.0 million of its environmental costs related to its MGP sites. As of March 31, 2019 and December 31, 2018, we had recovered approximately $11.6 million and $11.5 million, respectively, leaving approximately $2.4 million and $2.5 million, respectively, in regulatory assets for future recovery of environmental costs from FPU's customers.

Environmental liabilities for our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental remediation and related activities, including any potential future remediation costs for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.

The following is a summary of our remediation status and estimated costs to implement clean-up of our key MGP sites:

MGP Site (Jurisdiction)	Status	Estimated Cost to Clean up (Expect to Recover through Rates with Customers)
West Palm Beach (Florida)	Remedial actions approved by the Florida Department of Environmental Protection have been implemented on the east parcel of the site. We expect to implement similar remedial actions on other remaining portions, including the anticipated demolition of buildings on the site's west parcel in 2019.	Between $4.5 million to $15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.
Sanford (Florida)	In March 2018, the United States Environmental Protection Agency ("EPA") approved a "site-wide ready for anticipated use" status, which is the final step before delisting a site. Construction has been completed and restrictive covenants are in place to ensure protection of human health. The only remaining activity is long-term groundwater monitoring.	FPU's remaining remediation expenses, including attorneys' fees and costs, are anticipated to be less than $10,000. It is unlikely that FPU will incur any significant future costs associated with the site.
Winter Haven (Florida)	Remediation is ongoing.	Not expected to exceed $425,000, which includes costs of implementing institutional controls at the site.
Seaford (Delaware)	Conducted investigations of on-site and off-site impacts in the vicinity of the site, from 2014 through 2018, and submitted the findings to Delaware Department of Natural Resources and Environmental Control ("DNREC") in a March 2019 report. An interim action involving air-sparging/vapor extraction to mitigate on-site impact will be implemented, after the Work Plan has been submitted and approved by DNREC.	Between $273,000 and $465,000.
Cambridge (Maryland)	Currently in discussions with the MDE.	Unable to estimate.

6. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

Our Delmarva Peninsula natural gas distribution operations have asset management agreements with PESCO to manage their natural gas transportation and storage capacity. The agreements were effective as of April 1, 2017, and each has a three-year term, expiring on March 31, 2020.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with Eastern Gas & Water Investment Company, LLC ("EGWIC") to purchase propane through May 2019. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices. Sandpiper's remaining commitment at March 31, 2019 was approximately 288,000 gallons. Sandpiper has entered into an agreement with EGWIC to purchase any remaining assets at the end of the lease term and will transfer them to Sharp.

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC through May 2019. Sharp's remaining commitment as of March 31, 2019 was approximately 288,000 gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC.

Chesapeake Utilities' Florida Division has firm transportation service contracts with Florida Gas Transmission Company ("FGT") and Gulfstream. Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake Utilities is contingently liable to FGT and Gulfstream should any party, that acquired the capacity through release, fail to pay the capacity charge.

FPU's electric supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with Florida Power & Light Company requires FPU to meet or exceed a debt service coverage ratio of 1.25 times based on the results of the prior 12 months. If FPU fails to meet this ratio, it must provide an irrevocable letter of credit or pay all amounts outstanding under the agreement within five business days. FPU's electric supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of two times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken, or proposed to be taken, to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could also result in FPU having to provide an irrevocable letter of credit. As of March 31, 2019, FPU was in compliance with all of the requirements of its fuel supply contracts.

Eight Flags provides electricity and steam generation services through its CHP plant located on Amelia Island, Florida. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU pursuant to a 20-year power purchase agreement for distribution to our electric customers. In July 2016, Eight Flags also started selling steam, pursuant to a separate 20-year contract, to the landowner on which the CHP plant is located. The CHP plant is powered by natural gas transported by FPU through its distribution system and Peninsula Pipeline through its intrastate pipeline.

Corporate Guarantees

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily PESCO. These corporate guarantees provide for the payment of natural gas purchases in the event that PESCO defaults. PESCO has never defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at March 31, 2019 was approximately $77.3 million, with the guarantees expiring on various dates through December 2020.

Chesapeake Utilities also guarantees the payment of FPU's first mortgage bonds. The maximum exposure under this guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU's first mortgage bonds approximate their carrying values (see Note 14, *Long-Term Debt*, for further details).

As of March 31, 2019, we have issued letters of credit totaling approximately $7.0 million related to the electric transmission services for FPU's electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, the payment of natural gas purchases for PESCO, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through March 2020. There have been no draws on these letters of credit as of March 31, 2019. We do not anticipate that the counterparties will draw upon these letters of credit, and we expect that they will be renewed to the extent necessary in the future.

7. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance.

Our operations are comprised of two reportable segments:

- *Regulated Energy*. Includes energy distribution and transmission services (natural gas distribution, natural gas transmission and electric distribution operations). All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.
- *Unregulated Energy.* Includes energy transmission, energy generation (the operations of our Eight Flags' CHP plant), propane operations, the new mobile compressed natural gas utility and pipeline solutions subsidiary, and other energy services (natural gas marketing and related services). These operations are unregulated as to their rates and services. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

The remainder of our operations is presented as "Other businesses and eliminations," which consists of unregulated subsidiaries that own real estate leased to Chesapeake Utilities, as well as certain corporate costs not allocated to other operations.

The following table presents financial information about our reportable segments:

	Three Months Ended March 31,	
	2019	2018
(in thousands)		
Operating Revenues, Unaffiliated Customers		
Regulated Energy	$ 100,739	$ 105,954
Unregulated Energy	126,877	133,402
Total operating revenues, unaffiliated customers	$ 227,616	$ 239,356
Intersegment Revenues [1]		
Regulated Energy	$ 2,879	$ 3,439
Unregulated Energy	11,225	11,965
Other businesses	132	194
Total intersegment revenues	$ 14,236	$ 15,598
Operating Income		
Regulated Energy	$ 29,741	$ 26,711
Unregulated Energy	15,127	13,684
Other businesses and eliminations	(875)	11
Operating income	43,993	40,406
Other income (expense), net	(45)	68
Interest charges	5,710	3,664
Income before Income Taxes	38,238	36,810
Income taxes	9,574	9,955
Net Income	$ 28,664	$ 26,855

[1] All significant intersegment revenues are billed at market rates and have been eliminated from consolidated operating revenues.

(in thousands)	March 31, 2019	December 31, 2018
Identifiable Assets		
Regulated Energy segment	$ 1,343,061	$ 1,345,805
Unregulated Energy segment	296,836	306,045
Other businesses and eliminations	42,900	41,821
Total identifiable assets	$ 1,682,797	$ 1,693,671

Our operations are entirely domestic.

8. Stockholder's Equity

Accumulated Other Comprehensive Loss

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options natural gas swaps and futures contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated other comprehensive loss. The following tables present the changes in the balance of accumulated other comprehensive (loss)/income as of March 31, 2019 and 2018. All amounts except the stranded tax reclassification are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2018	$ (5,928)	$ (785)	$ (6,713)
Other comprehensive income before reclassifications	—	3,021	3,021
Amounts reclassified from accumulated other comprehensive income/(loss)	107	(39)	68
Net current-period other comprehensive income	107	2,982	3,089
Prior-year reclassification	—	(115)	(115)
As of March 31, 2019	$ (5,821)	$ 2,082	$ (3,739)
(in thousands)			
As of December 31, 2017	$ (4,743)	$ 471	$ (4,272)
Other comprehensive loss before reclassifications	—	(2,232)	(2,232)
Amounts reclassified from accumulated other comprehensive income/(loss)	94	444	538
Net prior-period other comprehensive income/(loss)	94	(1,788)	(1,694)
Stranded tax reclassification to retained earnings	(1,022)	115	(907)
As of March 31, 2018	$ (5,671)	$ (1,202)	$ (6,873)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three months ended March 31, 2019 and 2018. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	Three Months Ended March 31,	
	2019	2018
(in thousands)		
Amortization of defined benefit pension and postretirement plan items:		
Prior service credit [1]	$ 19	$ 19
Net loss[1]	(163)	(149)
Total before income taxes	(144)	(130)
Income tax benefit	37	36
Net of tax	$ (107)	$ (94)
Gains and losses on commodity contracts cash flow hedges:		
Propane swap agreements [2]	$ 606	$ (464)
Natural gas swaps [2]	11	(450)
Natural gas futures [2]	(573)	298
Total before income taxes	44	(616)
Income tax benefit (expense)	(5)	172
Net of tax	39	(444)
Total reclassifications for the period	$ (68)	$ (538)

[1] These amounts are included in the computation of net periodic costs (benefits). See Note 9, *Employee Benefit Plans*, for additional details.

[2] These amounts are included in the effects of gains and losses from derivative instruments. See Note 12, *Derivative Instruments*, for additional details.

Amortization of defined benefit pension and postretirement plan items is included in operations expense, and gains and losses on propane swap agreements, call options and natural gas futures contracts are included in cost of sales in the accompanying condensed consolidated statements of income. The income tax benefit is included in income tax expense in the accompanying condensed consolidated statements of income.

9. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three months ended March 31, 2019 and 2018 are set forth in the following tables:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended March 31,	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**
(in thousands)										
Interest cost	$ 105	$ 97	$ 615	$ 592	$ 21	$ 21	$ 10	$ 10	$ 12	$ 12
Expected return on plan assets	(127)	(138)	(693)	(774)	—	—	—	—	—	—
Amortization of prior service credit	—	—	—	—	—	—	(19)	(19)	—	—
Amortization of net loss	101	88	129	109	26	25	12	15	—	—
Net periodic cost (benefit)	79	47	51	(73)	47	46	3	6	12	12
Amortization of pre-merger regulatory asset	—	—	190	191	—	—	—	—	2	2
Total periodic cost	$ 79	$ 47	$ 241	$ 118	$ 47	$ 46	$ 3	$ 6	$ 14	$ 14

We expect to record pension and postretirement benefit costs of approximately $1.3 million for 2019. Included in these costs is approximately $543,000 related to continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU's regulated energy operations for the changes in funded status that occurred, but were not recognized, as part of net periodic benefit costs prior to the FPU merger in 2009. This was deferred as a regulatory asset by FPU prior to the merger, to be recovered through rates pursuant to a previous order by the Florida PSC. The unamortized balance of this regulatory asset was approximately $351,000 and approximately $543,000 at March 31, 2019 and December 31, 2018, respectively. The other than service cost components of the net periodic costs have been recorded or reclassified to other income (expense), net in the condensed consolidated statements of income.

Pursuant to a Florida PSC order, FPU continues to record, as a regulatory asset, a portion of the unrecognized pension and postretirement benefit costs related to its regulated operations after the FPU merger. The portion of the unrecognized pension and postretirement benefit costs related to FPU's unregulated operations and Chesapeake Utilities' operations is recorded to accumulated other comprehensive loss.

The following tables present the amounts included in the regulatory asset and accumulated other comprehensive loss that were recognized as components of net periodic benefit cost during the three months ended March 31, 2019 and 2018:

For the Three Months Ended March 31, 2019	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (19)	$ —	$ (19)
Net loss	101	129	26	12	—	268
Total recognized in net periodic benefit cost	101	129	26	(7)	—	249
Recognized from accumulated other comprehensive loss [1]	101	24	26	(7)	—	144
Recognized from regulatory asset	—	105	—	—	—	105
Total	$ 101	$ 129	$ 26	$ (7)	$ —	$ 249

For the Three Months Ended March 31, 2018 *(in thousands)*	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service credit	$ —	$ —	$ —	$ (19)	$ —	$ (19)
Net loss	88	109	25	15	—	237
Total recognized in net periodic benefit cost	88	109	25	(4)	—	218
Recognized from accumulated other comprehensive loss [1]	88	21	25	(4)	—	130
Recognized from regulatory asset	—	88	—	—	—	88
Total	$ 88	$ 109	$ 25	$ (4)	$ —	$ 218

[1] See Note 8, *Stockholder's Equity*.

During the three months ended March 31, 2019, we contributed approximately $33,000 to the Chesapeake Pension Plan and approximately $233,000 to the FPU Pension Plan. We expect to contribute a total of approximately $163,000 and approximately $1.2 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2019, which represents the minimum annual contribution payments required.

The Chesapeake SERP, the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake SERP for the three months ended March 31, 2019, were approximately $38,000. We expect to pay total cash benefits of approximately $383,000 under the Chesapeake SERP in 2019. Cash benefits paid under the Chesapeake Postretirement Plan, primarily for medical claims for the three months ended March 31, 2019, were approximately $1,000. We estimate that approximately $96,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2019. Cash benefits paid under the FPU Medical Plan, primarily for medical claims for the three months ended March 31, 2019, were approximately $6,000. We estimate that approximately $94,000 will be paid for such benefits under the FPU Medical Plan in 2019.

10. Investments

The investment balances at March 31, 2019 and December 31, 2018, consisted of the following:

(in thousands)	March 31, 2019	December 31, 2018
Rabbi trust (associated with the Non-Qualified Deferred Compensation Plan)	$ 7,484	$ 6,689
Investments in equity securities	25	22
Total	$ 7,509	$ 6,711

We classify these investments as trading securities and report them at their fair value. For the three months ended March 31, 2019 and 2018, we recorded a net unrealized gain of approximately $727,000 and a net unrealized loss of approximately $44,000, respectively, in other expense, net in the condensed consolidated statements of income related to these investments. For the investment in the Rabbi Trust, we also have recorded an associated liability, which is included in other pension and benefit costs in the condensed consolidated balance sheets and is adjusted each period for the gains and losses incurred by the investments in the Rabbi Trust.

11. Share-Based Compensation

Our non-employee directors and key employees are 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.

The table below presents the amounts included in net income related to share-based compensation expense for the three months ended March 31, 2019 and 2018:

	Three Months Ended March 31,	
	2019	2018
(in thousands)		
Awards to non-employee directors	$ 149	$ 135
Awards to key employees	338	1,385
Total compensation expense	487	1,520
Less: tax benefit	(127)	(416)
Share-based compensation amounts included in net income	$ 360	$ 1,104

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 2018, each of our non-employee directors received an annual retainer of 792 shares of common stock under the SICP for service as a director through the 2019 Annual Meeting of Stockholders. Our former President and Chief Executive Officer, Michael P. McMasters, retired on December 31, 2018 and continued as a member of the Board of Directors beginning January 1, 2019. Mr. McMasters received a pro-rated grant of 276 shares of common stock under the SICP for service as a non-employee director from January 1, 2019 through the 2019 Annual Meeting of Stockholders. These shares were issued and vested in January 2019 at a weighted average fair value of $75.70.

At March 31, 2019, there was approximately $52,000 of unrecognized compensation expense related to shares granted to non-employee directors. This expense will be recognized over the remaining service period ending April 30, 2019. See Note 1, *Summary of Accounting Policies*, for additional information regarding ASU 2018-07 and its impact on the accounting for non-employee share-based payments.

Key Employees

The table below presents the summary of the stock activity for awards to key employees for the three months ended March 31, 2019:

	Number of Shares	Weighted Average Fair Value
Outstanding—December 31, 2018	131,741	$ 67.24
Granted	45,016	$ 91.19
Vested	(25,831)	$ 67.08
Expired	(15,086)	$ 69.28
Outstanding—March 31, 2019	135,840	$ 74.05

In February 2019, our Board of Directors granted awards of 45,016 shares of common stock to key employees under the SICP. The shares granted are multi-year awards that will vest at the end of the three-year service period ending December 31, 2021. All of these stock awards are earned based upon the successful achievement of long-term financial results, which comprise market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the grant date of each award. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

In March 2019, upon the election of certain of our executive officers, we withheld shares with a value at least equivalent to each such executive officer's minimum statutory obligation for applicable income and other employment taxes related to shares that we awarded in February 2019 for the performance period ended December 31, 2018, remitted the cash to the appropriate taxing authorities, and paid the balance of such awarded shares to each such executive officer. We withheld 7,635 shares, 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 combined payments for the employees' tax obligations to the taxing authorities were approximately $692,000.

At March 31, 2019, the aggregate intrinsic value of the SICP awards granted to key employees was approximately $12.4 million. At March 31, 2019, there was approximately $4.3 million of unrecognized compensation cost related to these awards, which is expected to be recognized as expense from 2019 through 2021.

Stock Options

We did not have any stock options outstanding at March 31, 2019 or 2018, nor were any stock options issued during these periods.

12. Derivative Instruments

We use derivative and non-derivative contracts to manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to our customers. Aspire Energy has entered into contracts with producers to secure natural gas to meet its obligations. Purchases under these contracts typically either do not meet the definition of derivatives or are considered "normal purchases and normal sales" and are accounted for on an accrual basis. Both our propane distribution and natural gas marketing operations may also enter into fair value hedges of their inventory or cash flow hedges of their future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of March 31, 2019, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Volume of Derivative Activity

As of March 31, 2019, the volume of our open commodity derivative contracts were as follows:

Business unit	Commodity	Quantity hedged (in millions)	Designation	Longest Expiration date of hedge
PESCO	Natural gas (Dts)	21.7	Cash flows hedges	December 2022
PESCO	Natural gas (Dts)	3.8	Not designated	March 2021
Sharp	Propane (gallons)	5.4	Cash flows hedges	June 2021

PESCO entered into natural gas futures contracts associated with the purchase and sale of natural gas to specific customers. We designated and accounted for them as cash flow hedges. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss) and later recognized in the statement of income in the same period and in the same line item as the hedged transaction. We expect to reclassify approximately $2.1 million from accumulated other comprehensive loss to earnings during the next 12-month period ending March 31, 2020.

Sharp entered into futures and swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with the propane volumes expected to be purchased during the heating season. Under the futures and swap agreements, Sharp will receive the difference between: (i) the index prices (Mont Belvieu prices in August 2018 through June 2021), and (ii) the per gallon propane swap prices, to the extent the index prices exceed the contracted prices. If the index prices are lower than the swap prices, Sharp will pay the difference. We designated and accounted for propane swaps as cash flows hedges. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss) and later recognized in the statement of income in the same period and in the same line item as the hedged transaction. We expect to reclassify approximately $503,000 from accumulated other comprehensive income (loss) to earnings during the next 12-month period ending March 31, 2020.

Balance Sheet Offsetting

PESCO has entered into master netting agreements with counterparties that enable it to net the counterparties' outstanding accounts receivable and payable, which are presented on a net basis in the condensed consolidated balance sheets. The following table summarizes the accounts receivable and payable on a gross and net basis at March 31, 2019 and December 31, 2018:

	At March 31, 2019		
(in thousands)	Gross amounts	Amounts offset	Net amounts
Accounts receivable	$ 8,832	$ 3,264	$ 5,568
Accounts payable	$ 15,906	$ 3,264	$ 12,642

	At December 31, 2018		
(in thousands)	Gross amounts	Amounts offset	Net amounts
Accounts receivable	$ 12,368	$ 3,834	$ 8,534
Accounts payable	$ 24,741	$ 3,834	$ 20,907

Broker Margin

Futures exchanges have contract specific margin requirements that require the posting of cash or cash equivalents relating to traded contracts. Margin requirements consist of initial margin that is posted upon the initiation of a position, maintenance margin that is usually expressed as a percent of initial margin, and variation margin that fluctuates based on the daily MTM relative to maintenance margin requirements. We maintain separate broker margin accounts for Sharp and PESCO. The balances are as follows:

(in thousands)	Balance Sheet Location	At March 31, 2019	At December 31, 2018
PESCO	Other Current Assets	$ (335)	$ 2,810

Financial Statements Presentation

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency.

The fair values of the derivative contracts recorded in the condensed consolidated balance sheets as of March 31, 2019 and December 31, 2018, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	March 31, 2019	December 31, 2018
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Derivative assets, at fair value	$ 2,122	$ 4,024
Derivatives designated as fair value hedges			
Propane put options	Derivative assets, at fair value	—	71
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative assets, at fair value	7,055	9,059
Propane swap agreements	Derivative assets, at fair value	44	11
Total asset derivatives		$ 9,221	$ 13,165

		Liability Derivatives	
		Fair Value As Of	
(in thousands)	Balance Sheet Location	March 31, 2019	December 31, 2018
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Derivative liabilities, at fair value	$ 2,638	$ 4,562
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative liabilities, at fair value	3,533	8,705
Propane swap agreements	Derivative liabilities, at fair value	627	1,604
Total liability derivatives		$ 6,798	$ 14,871

The effects of gains and losses from derivative instruments on the condensed consolidated financial statements are as follows:

		Amount of Gain (Loss) on Derivatives:	
	Location of Gain	For the Three Months Ended March 31,	
(in thousands)	(Loss) on Derivatives	2019	2018
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Cost of sales	$ (22)	$ (2,835)
Propane swap agreements	Cost of sales	—	(9)
Derivatives designated as cash flow hedges			
Propane swap agreements	Cost of sales	606	(464)
Propane swap agreements	Other comprehensive income (loss)	1,009	(992)
Natural gas futures contracts	Cost of sales	(573)	298
Natural gas swap contracts	Cost of sales	11	(450)
Natural gas swap contracts	Other comprehensive income (loss)	3,226	(1,617)
Natural gas futures contracts	Other comprehensive income (loss)	(59)	65
Total		$ 4,198	$ (6,004)

As of March 31, 2019, the following amounts were recorded in the condensed consolidated balance sheets related to fair value hedges:

(in thousands)	Carrying Amount of Hedged Item		Cumulative Adjustment Included in Carrying Amount of Hedged Item	
Balance Sheet Location of Hedged Items	At March 31, 2019	At December 31, 2018	At March 31, 2019	At December 31, 2018
Inventory	$ 6	$ 212	$ —	$ —

13. Fair Value of Financial Instruments

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The three levels of the fair value hierarchy are the following:

Fair Value Hierarchy	Description of Fair Value Level	Fair Value Technique Utilized
Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities	*Investments - equity securities* - The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities. *Investments - mutual funds and other* - The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability	*Derivative assets and liabilities* - The fair values of forward contracts are measured using market transactions in either the listed or over-the-counter markets. The fair value of the propane put/call options, swap agreements and natural gas futures contracts are measured using market transactions for similar assets and liabilities in either the listed or over-the-counter markets.
Level 3	Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity)	*Investments - guaranteed income fund* - The fair values of these investments are recorded at the contract value, which approximates their fair value.

Financial Assets and Liabilities Measured at Fair Value

The following tables summarize our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy as of March 31, 2019 and December 31, 2018:

		Fair Value Measurements Using:		
As of March 31, 2019 *(in thousands)*	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments—equity securities	$ 25	$ 25	$ —	$ —
Investments—guaranteed income fund	695	—	—	695
Investments—mutual funds and other	6,789	6,789	—	—
Total investments	7,509	6,814	—	695
Derivative assets	9,221	—	9,221	—
Total assets	$ 16,730	$ 6,814	$ 9,221	$ 695
Liabilities:				
Derivative liabilities	$ 6,798	$ —	$ 6,798	$ —

As of December 31, 2018 *(in thousands)*	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments—equity securities	$ 22	$ 22	$ —	$ —
Investments—guaranteed income fund	686	—	—	686
Investments—mutual funds and other	6,003	6,003	—	—
Total investments	6,711	6,025	—	686
Derivative assets	13,165	—	13,165	—
Total assets	$ 19,876	$ 6,025	$ 13,165	$ 686
Liabilities:				
Derivative liabilities	$ 14,871	$ —	$ 14,871	$ —

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the three months ended March 31, 2019 and 2018:

(in thousands)	Three Months Ended March 31, 2019	2018
Beginning Balance	$ 686	$ 648
Purchases and adjustments	6	(48)
Investment income	3	2
Ending Balance	$ 695	$ 602

Investment income from the Level 3 investments is reflected in other expense, (net) in the consolidated statements of income.

At March 31, 2019, 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 March 31, 2019, long-term debt which includes current maturities but excludes capital lease obligations, had a carrying value of approximately $357.2 million, compared to the estimated fair value of $361.3 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, and with adjustments for duration, optionality, and risk profile. At December 31, 2018, long-term debt, which includes the current maturities but excludes a capital lease obligation, had a carrying value of approximately $327.2 million, compared to a fair value of approximately $323.8 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	March 31, 2019	December 31, 2018
FPU secured first mortgage bonds [1]:		
9.08% bond, due June 1, 2022	$ 7,987	$ 7,986
Uncollateralized senior notes:		
5.50% note, due October 12, 2020	4,000	4,000
5.93% note, due October 31, 2023	15,000	15,000
5.68% note, due June 30, 2026	23,200	23,200
6.43% note, due May 2, 2028	7,000	7,000
3.73% note, due December 16, 2028	20,000	20,000
3.88% note, due May 15, 2029	50,000	50,000
3.25% note, due April 30, 2032	70,000	70,000
3.48% note, due May 31, 2038	50,000	50,000
3.58% note, due November 30, 2038	50,000	50,000
Term Note due January 21, 2020	30,000	30,000
Term Note due February 28, 2020	30,000	—
Promissory notes	—	26
Finance lease obligation	909	1,310
Less: debt issuance costs	(589)	(567)
Total long-term debt	357,507	327,955
Less: current maturities	(71,509)	(11,935)
Total long-term debt, net of current maturities	$ 285,998	$ 316,020

[1] FPU secured first mortgage bonds are guaranteed by Chesapeake Utilities.

Term Notes

In December 2018, we issued a $30.0 million unsecured term note through PNC Bank N.A. with maturity date of January 21, 2020. The interest rate at March 31, 2019 and December 31, 2018 was 3.24% and 3.23%, respectively, which equals one month LIBOR rate plus 75 basis points. In January 2019, we issued a $30.0 million unsecured term note through Branch Banking and Trust Company, with a maturity date of February 28, 2020. The interest rate at March 31, 2019 was 3.24%, which equals the one month LIBOR rate plus 75 basis points. As of March 31, 2019, these term notes totaling $60.0 million are included in the current maturities of long-term debt.

Shelf Agreements

We have entered into Shelf Agreements with Prudential, MetLife and NYL, whom are under no obligation to purchase any unsecured debt. We entered into the Prudential Shelf Agreement, totaling $150.0 million, in October 2015, and we issued $70.0 million of 3.25% unsecured debt in April 2017. The Prudential Shelf Agreement was then amended in September 2018 to increase the borrowing capacity back up to $150.0 million, and Prudential accepted our request to purchase our unsecured debt of $100.0 million at an interest rate of 3.98% on or before August 20, 2019. We entered into the NYL Shelf Agreement, totaling $100.0 million, in March 2017, and we issued unsecured debt totaling $100.0 million during 2018. The NYL Shelf Agreement was amended in November 2018 to add incremental borrowing capacity of $50.0 million. As of March 31, 2019, we had not requested that MetLife purchase unsecured senior debt under the MetLife Shelf Agreement, which we entered into in March 2017. The following table summarizes the borrowing information under our Shelf Agreements at March 31, 2019:

(in thousands)	Total Borrowing Capacity	Less: Amount of Debt Issued	Less: Unfunded Commitments	Remaining Borrowing Capacity
Shelf Agreement				
Prudential Shelf Agreement	$ 220,000	$ (70,000)	$ (100,000)	$ 50,000
MetLife Shelf Agreement	150,000	—	—	150,000
NYL Shelf Agreement	150,000	(100,000)	—	50,000
Total	$ 520,000	$ (170,000)	$ (100,000)	$ 250,000

The Shelf Agreements or Shelf Notes set forth certain business covenants to which we are subject when any note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

15. Leases

We have entered into lease arrangements for office space, land, equipment, pipeline facilities and warehouses. These leases have been entered into to better enable us to conduct our business operations in the regions in which we operate. Office space is leased to provide adequate workspace for all our employees in several locations throughout the Mid-Atlantic, Mid-West and in Florida. We lease land at various locations throughout our service territories to enable us to inject natural gas into underground storage and distribution systems, for bulk storage capacity, for our propane operations and for storage of equipment used in repairs and maintenance of our infrastructure. We lease natural gas compressors to ensure timely and reliable transportation of natural gas to our customers. Additionally, we lease a pipeline to deliver natural gas to an industrial customer in Polk County, Florida. We lease warehouses to store equipment and materials used in repairs and maintenance for our businesses.

Some of our leases are subject to annual changes in the Consumer Price Index ("CPI"). While lease liabilities are not re-measured as a result of changes to the CPI, changes to the CPI are treated as variable lease payments and recognized in the period in which the obligation for those payments was incurred. A 100-basis-point increase in CPI would have resulted in immaterial additional annual lease costs.

Most of our leases include options to renew, with renewal terms that can extend the lease term from one to 25 years or more. The exercise of lease renewal options is at our sole discretion. The amounts disclosed in our condensed consolidated balance sheet at March 31, 2019, pertaining to the right of use assets and lease liabilities, are measured based on our current expectations of exercising our available renewal options.

Our existing leases are not subject to any restrictions or covenants which preclude our ability to pay dividends, obtain financing or enter into additional leases.

We utilize our incremental borrowing rate, as the basis to calculate the present value of future lease payments, at lease commencement. Our incremental borrowing rate represents the rate that we would have to pay to borrow funds on a collateralized basis over a similar term and in a similar economic environment.

Leases with an initial term of 12 months or less are not recorded on our balance sheet; we recognize lease expense for these leases on a straight-line basis over the lease term.

We have elected not to separate non-lease components from all classes of our existing leases. Non-lease components have been accounted for as part of the single lease component to which they are related.

As of March 31, 2019, we have not entered into any leases, which have not yet commenced, that would entitle us to significant rights or create additional obligations. The following table presents information related to our total lease cost included in our condensed consolidated statements of income:

(in thousands)	Classification	Three Months Ended March 31, 2019	2018
Operating lease cost [1]	Operations expense	$ 635	$ 1,107
Finance lease cost			
Amortization of lease assets	Depreciation and amortization	401	358
Interest on lease liabilities	Interest expense	4	17
Net lease cost		$ 1,040	$ 1,482

[1] Includes short-term leases and variable lease costs, which are immaterial

The following table presents the balance and classifications of our right of use assets and lease liabilities included in our consolidated balance sheet at March 31, 2019:

(in thousands)	Balance sheet classification	Amount
Assets		
Operating lease assets	Operating lease right-of-use assets	$ 12,523
Finance lease assets	Property, plant and equipment	1,839
Total lease assets		$ 14,362
Liabilities		
Current		
Operating lease liabilities	Other accrued liabilities	$ 1,642
Finance lease liabilities	Current portion of long-term debt	909
Noncurrent		
Operating lease liabilities	Other liabilities	10,873
Finance lease liabilities	Long-term debt	—
Total lease liabilities		$ 13,424

The following table presents our weighted-average remaining lease terms and weighted-average discount rates for our operating and financing leases at March 31, 2019:

	At March 31, 2019
Weighted-average remaining lease term (*in years*)	
Operating leases	9.32
Finance leases	0.17
Weighted-average discount rate	
Operating leases	3.8%
Finance leases	3.5%

The following table presents additional information related to cash paid for amounts included in the measurement of lease liabilities included in our condensed consolidated statements of cash flows as of March 31, 2019 and March 31, 2018:

(in thousands)	Three Months Ended March 31, 2019	2018
Operating cash flows from operating leases	$ 537	$ 1,018
Operating cash flows from finance leases	4	17
Financing cash flows from finance leases	401	358

The following table presents the future undiscounted maturities of our operating and financing leases at March 31, 2019 and for each of the next five years and thereafter:

(in thousands)	Operating Leases [1]	Finance Leases	Total
Remainder of 2019	$ 1,539	$ 910	$ 2,449
2020	2,045	—	2,045
2021	1,765	—	1,765
2022	1,659	—	1,659
2023	1,669	—	1,669
2024	1,431	—	1,431
Thereafter	4,860	—	4,860
Total lease payments	$ 14,968	$ 910	$ 15,878
Less: Interest	2,453	1	2,454
Present value of lease liabilities	$ 12,515	$ 909	13,424

(1) Operating lease payments include $3.8 million related to options to extend lease terms that are reasonably certain of being exercised.

The following table presents future minimum lease payments for our operating leases at December 31, 2018 under ASC 840 and is being presented for comparative purposes:

Year(s)	2019	2020	2021	2022	2023	Thereafter	Total
(in thousands)							
Expected payments	$2,349	$1,998	$1,761	$1,689	$1,642	$5,398	$14,837

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations is designed to provide a reader of the financial statements with a narrative report on our financial condition, results of operations and liquidity. This discussion and analysis should be read in conjunction with the attached unaudited condensed consolidated financial statements and notes thereto and our Annual Report on Form 10-K for the year ended December 31, 2018, including the audited consolidated financial statements and notes thereto.

Safe Harbor for Forward-Looking Statements

We make statements in this Quarterly Report on Form 10-Q that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as "project," "believe," "expect," "anticipate," "intend," "plan," "estimate," "continue," "potential," "forecast" or other similar words, or future or conditional verbs such as "may," "will," "should," "would" or "could." These statements represent our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. Forward-looking statements speak only as of the date they are made or as of the date indicated and we do not undertake any obligation to update forward-looking statements as a result of new information, future events or otherwise. These statements are subject to many risks, uncertainties and other important factors that could cause actual future results to differ materially from those expressed in the forward-looking statements. In addition to the risk factors described under Item 1A, Risk Factors in our 2018 Annual Report on Form 10-K, such factors include, but are not limited to:

- state and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed and the degree to which competition enters the electric and natural gas industries;
- the outcomes of regulatory, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the related costs are adequately covered by insurance or recoverable in rates;
- the impact of significant changes to current tax regulations and rates;
- the timing of certification authorizations associated with new capital projects and the ability to construct facilities at or below estimated costs;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now, or may in the future, own or operate;
- possible increased federal, state and local regulation of the safety of our operations;
- the economy in our service territories or markets, the nation, and worldwide, including the impact of economic conditions (which we do not control) on demand for electricity, natural gas, propane or other fuels;
- risks related to cyber-attacks or cyber-terrorism that could disrupt our business operations or result in failure of information technology systems;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- customers' preferred energy sources;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the effect of competition on our businesses;
- the timing and extent of changes in commodity prices and interest rates;
- the effect of spot, forward and future market prices on our various energy businesses;
- the extent of our success in connecting natural gas and electric supplies to transmission systems, establishing and maintaining key supply sources; and expanding natural gas and electric markets;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the capital-intensive nature of our regulated energy businesses;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the ability to successfully execute, manage and integrate a merger, acquisition or divestiture of assets or businesses and the related regulatory or other conditions associated with the merger, acquisition or divestiture;
- the impact on our costs and funding obligations, under our pension and other post-retirement benefit plans, of potential downturns in the financial markets, lower discount rates, and costs associated with health care legislation and regulation;
- the ability to continue to hire, train and retain appropriately qualified personnel; and
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies.

Introduction

We are an energy delivery company engaged in the distribution of natural gas, propane and electricity; the transmission of natural gas; the generation of electricity and steam, and in providing related services to our customers.

Our strategy is focused on growing earnings from a stable utility foundation and investing in related businesses and services that provide opportunities for returns greater than traditional utility returns. We are focused on identifying and developing opportunities across the energy value chain, with emphasis on midstream and downstream investments that are accretive to earnings per share and consistent with our long-term growth strategy.

Our strategy is to consistently produce industry-leading total shareholder returns by profitably investing capital into opportunities that leverage our skills and expertise in energy distribution and transmission to achieve high levels of service and growth. The key elements of our strategy include:

- capital investment in growth opportunities that generate our target returns;
- expanding our energy distribution and transmission operations within our existing service areas as well as into new geographic areas;
- providing new services in our current service areas;
- expanding our footprint in potential growth markets through strategic acquisitions;
- entering new energy markets and businesses that complement our existing operations and growth strategy; and
- operating as a customer-centric full-service energy supplier/partner/provider of safe and reliable service.

Our employees strive to build meaningful connections that generate opportunities to grow our businesses, develop new markets, and enrich the communities in which we live, work and serve.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is normally highest due to colder temperatures.

The following discussions and those later in the document on operating income and segment results include the use of the term "gross margin," which is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities, and excludes depreciation, amortization and accretion. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by us under our allowed rates for regulated energy operations and under our competitive pricing structures for unregulated energy operations. Our management uses gross margin in measuring our business units' performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

Earnings per share information is presented on a diluted basis, unless otherwise noted.

Results of Operations for the Three Months ended March 31, 2019

Overview

Chesapeake Utilities is a Delaware corporation formed in 1947. We are a diversified energy company engaged, through our operating divisions and subsidiaries, in regulated energy, unregulated energy and other businesses. We operate primarily on the Delmarva Peninsula and in Florida, Pennsylvania and Ohio and provide services centered on energy distribution, energy transmission, energy generation, propane operations and other energy services. These services include: natural gas distribution, transmission, and marketing; electric distribution and generation; propane operations; steam generation; and other energy-related services.

Operational Highlights

Our net income for the quarter ended March 31, 2019 was $28.7 million, or $1.74 per share. This represents an increase of $1.8 million, or $0.10 per share, compared to net income of $26.9 million, or $1.64 per share, reported for the same quarter in 2018. Operating income increased by $3.6 million for the three months ended March 31, 2019, compared to the same period in the prior year, as margin increased by $10.1 million, or 11.1 percent, and was offset by a $1.8 million increase in growth-related depreciation, amortization and property taxes and a $4.7 million increase in other operating expenses. In addition, a final order by the Florida PSC allowing us to retain TCJA tax savings associated with lower federal income tax rates resulted in the reversal, during the first quarter of 2019, of $1.3 million in reserves for customer refunds recorded in 2018.

Our net income for the quarter was impacted by an increase in interest charges of $2.0 million, compared to the same period in 2018. The increase was attributable primarily to an increase of $980,000 in interest on higher levels of short-term borrowings, and an increase of $742,000 in interest on long-term debt, largely as a result of the issuance of the NYL Shelf Notes in May and November 2018 and term notes issued in December 2018 and January 2019 to finance the restoration of service to customers who lost service due to the impact of Hurricane Michael.

	Three Months Ended March 31,		Increase
	2019	2018	(decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$ 29,741	$ 26,711	$ 3,030
Unregulated Energy segment	15,127	13,684	1,443
Other businesses and eliminations	(875)	11	(886)
Operating Income	$ 43,993	$ 40,406	$ 3,587
Other expense income (expense), net	(45)	68	(113)
Interest charges	5,710	3,664	2,046
Pre-tax Income	38,238	36,810	1,428
Income taxes	9,574	9,955	(381)
Net Income	$ 28,664	$ 26,855	$ 1,809
Earnings Per Share of Common Stock			
Basic	$ 1.75	$ 1.64	$ 0.11
Diluted	$ 1.74	$ 1.64	$ 0.10

Key variances, between the first quarter of 2019 and the first quarter of 2018, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
First Quarter of 2018 Reported Results	**$ 36,810**	**$ 26,855**	**$ 1.64**
Adjusting for Unusual Items:			
Net impact of PESCO's MTM activity	(5,591)	(4,088)	(0.24)
Impact of weather on customer consumption	(2,523)	(1,891)	(0.12)
2018 retained tax savings for certain Florida natural gas operations	1,321	990	0.06
	(6,793)	(4,989)	(0.30)
Increased (Decreased) Gross Margins:			
Absence of the 2018 Bomb Cyclone and capacity constraints cost for PESCO	5,545	4,157	0.25
Eastern Shore and Peninsula Pipeline service expansions*	4,266	3,198	0.19
Margin contribution from Marlin Gas Services and Ohl (assets acquired in December 2018)*	2,805	2,103	0.13
Natural gas distribution - customer growth (excluding service expansions)	1,451	1,088	0.06
Higher propane retail margins per gallon	1,259	944	0.06
Unregulated Energy customers' consumption growth	879	659	0.04
Aspire Energy rate increases	779	584	0.04
Other margin for PESCO operations	731	548	0.03
Natural gas distribution - change in customer consumption (non-weather)	(485)	(364)	(0.02)
Lower wholesale propane margins and sales	(453)	(340)	(0.02)
Conversion of Sandpiper customers to natural gas	382	287	0.02
Florida GRIP*	223	167	0.01
	17,382	13,031	0.79
Decreased (Increased) Other Operating Expenses:			
Depreciation, asset removal and property tax costs due to growth investments	(1,560)	(1,169)	(0.07)
Incentive compensation costs (based on timing and period-over-period results)	(1,931)	(1,448)	(0.09)
Operating expenses for Marlin Gas Services and Ohl (assets acquired in December 2018)	(1,157)	(867)	(0.05)
Benefits and other employee-related expenses	(732)	(549)	(0.03)
Payroll expense (increased staffing and annual salary increases)	(673)	(504)	(0.03)
Operating expenses to support growth for PESCO	(431)	(323)	(0.02)
	(6,484)	(4,860)	(0.29)
Interest charges	(2,046)	(1,534)	(0.09)
Change in effective tax rate	—	768	0.05
Net other changes	(631)	(607)	(0.06)
	(2,677)	(1,373)	(0.10)
First Quarter of 2019 Reported Results	**$ 38,238**	**$ 28,664**	**$ 1.74**

***See the Major Projects and Initiatives table.**

Summary of Key Factors

Recently Completed and Ongoing Major Projects and Initiatives

We constantly seek and develop additional projects and initiatives in order to increase shareholder value and serve our existing and new customers. The following table represents the major projects recently completed and currently underway. In the future, we will add new projects to this table as such projects are initiated.

	Gross Margin for the Period				
	Three Months Ended March 31,		Year Ended December 31,	Estimate for Fiscal	
in thousands	2019	2018	2018	2019	2020
Florida GRIP [1]	$ 3,565	$ 3,342	$ 13,323	$ 14,204	$ 15,565
2017 Eastern Shore System Expansion Project - including interim services	4,800	2,263	9,238	16,183	15,799
Tax benefit retained by certain Florida entities[2]	2,115	—	—	3,199	1,879
Northwest Florida Expansion	1,307	—	3,485	6,500	6,500
Western Palm Beach County, Florida Expansion	161	—	54	605	4,711
Marlin Gas Services	2,329	—	110	5,100	6,000
Ohl propane acquisition (rolled into Sharp)	476	—	—	1,200	1,236
Del-Mar Energy Pathway Project - including interim services	165	—	—	725	3,039
Total	$ 14,918	$ 5,605	$ 26,210	$ 47,716	$ 54,729

(1) All periods shown have been adjusted to reflect the lower customer rates as a result of the TCJA. Lower customer rates are offset by the corresponding decrease in federal income tax expense and have no negative impact on net income.
(2) The amount disclosed for the first quarter of 2019 includes tax savings of $1.3 million for the year ended December 31, 2018, due to an order by the Florida PSC allowing reversal of a TCJA refund reserve, recorded in 2018, which increased gross margin for the quarter by that amount.

Ongoing Growth Initiatives

GRIP

Florida GRIP is a natural gas pipe replacement program approved by the Florida PSC that allows automatic recovery, through rates, of costs associated with the replacement of mains and services. Since the program's inception in August 2012, we have invested $131.4 million of capital expenditures to replace 268 miles of qualifying distribution mains, including $4.1 million during the first three months of 2019. GRIP generated additional gross margin of $223,000 for the three months ended March 31, 2019 compared to the same period in 2018.

Major Projects and Initiatives Currently Underway

2017 Eastern Shore System Expansion Project

Eastern Shore has substantially completed the construction of a system expansion project that has increased its capacity by 26 percent. A few remaining segments are expected to be placed into service in various phases during the second quarter of 2019. The project generated $2.5 million in incremental gross margin during the three months ended March 31, 2019, compared to the same period in 2018. The project is expected to produce gross margin of approximately $16.2 million this year; $15.8 million annually, through 2022; and $13.2 million annually thereafter.

Northwest Florida Expansion Project

In May 2018, Peninsula Pipeline completed construction of transmission lines, and our Florida natural gas division completed construction of lateral distribution lines, to serve customers in Northwest Florida. The project generated incremental gross margin of $1.3 million for the three months ended March 31, 2019. The estimated annual gross margin from this project is $6.5 million, with the opportunity for additional margin as the remaining capacity is sold.

Western Palm Beach County Belvedere, Florida Project

Peninsula Pipeline is constructing four transmission lines to bring natural gas to our distribution system in West Palm Beach, Florida. The first phase of this project was placed into service in December 2018 and generated $161,000 in additional gross margin for the three months ended March 31, 2019. We expect to complete the remainder of the project in phases through early 2020, and we estimate that the project will generate gross margin of $605,000 in 2019 and approximately $4.7 million in future years once fully in service.

Marlin Gas Services

In December 2018, Marlin Gas Services, our newly created subsidiary, acquired certain operating assets of Marlin Gas Transport, a supplier of mobile compressed natural gas utility and pipeline solutions. The acquisition will allow us to offer solutions to supply interruption scenarios and provide other unique applications where pipeline supplies are unavailable or inadequate to meet customer requirements. Marlin Gas Services generated $2.3 million of incremental gross margin for the three months ended March 31, 2019. We estimate that this acquisition will generate additional annual gross margin of approximately $5.1 million in 2019 and $6.0 million annually thereafter.

Ohl Propane Acquisition

In December 2018, Sharp acquired certain propane customers and operating assets of Ohl. Located between two of Sharp's existing districts, Ohl provided propane distribution service to approximately 2,500 residential and commercial customers in Pennsylvania. The customers and assets acquired from Ohl have been assimilated into Sharp. The operations acquired from Ohl generated $476,000 of incremental gross margin for the three months ended March 31, 2019. We estimate that this acquisition will generate additional gross margin of approximately $1.2 million for Sharp in 2019, with the potential for additional growth in future years.

Del-Mar Energy Pathway Project

In September 2018, Eastern Shore filed for FERC authorization to construct the Del-Mar Energy Pathway project to provide an additional 14,300 dekatherms per day of capacity to four customers. The benefits of this project include additional natural gas transmission pipeline infrastructure in eastern Sussex County, Delaware, and the initial extension of Eastern Shore's pipeline system into Somerset County, Maryland. Interim services in advance of this project generated $165,000 for the three months ended March 31, 2019. The estimated annual gross margin from this project is approximately $725,000 in 2019, $3.0 million in 2020, $4.6 million in 2021 and $5.1 million annually thereafter. Eastern Shore anticipates that this project will be fully in-service by mid-2021, contingent upon FERC issuing authorization for the project by August 2019.

Regulatory Initiatives

Florida Tax Savings Related to TCJA

In the first quarter of 2019, the Florida PSC issued orders authorizing certain of our natural gas distribution operations to retain a portion of the tax savings associated with the lower federal tax rates resulting from the TCJA. We expect these savings to continue in future years.

Other major factors influencing gross margin

Weather and Consumption

Weather conditions accounted for a $2.5 million decrease in gross margin during the first quarter of 2019 compared to the same period in 2018. While period-over-period heating degree-days ("HDD") were essentially flat on the Delmarva Peninsula, extreme conditions during the 2018 "Bomb Cyclone" drove weather-related consumption in the first quarter of 2018 compared to the same period in 2019. The decrease in consumption on the Delmarva Peninsula accounted for $1.1 million in lower first quarter 2019 gross margin for the propane operations and $310,000 for the natural gas distribution operations. Weather in Florida was approximately 26 percent warmer in the first quarter of 2019, compared to the same period in 2018, and reduced consumption by propane, electric and natural gas distribution customers which resulted in decreased margin of approximately $951,000. The following table summarizes HDD and cooling degree-day ("CDD") variances from the 10-year average HDD/CDD ("Normal") for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31,		
	2019	2018	Variance
Delmarva			
Actual HDD	**2,322**	2,295	27
10-Year Average HDD ("Normal")	**2,362**	2,354	8
Variance from Normal	**(40)**	(59)	
Florida			
Actual HDD	**361**	490	(129)
10-Year Average HDD ("Normal")	**518**	517	1
Variance from Normal	**(157)**	(27)	
Ohio			
Actual HDD	**2,996**	2,991	5
10-Year Average HDD ("Normal")	**3,045**	3,069	(24)
Variance from Normal	**(49)**	(78)	
Florida			
Actual CDD	**134**	139	(5)
10-Year Average CDD ("Normal")	**97**	89	8
Variance from Normal	**37**	50	

Natural Gas Distribution Margin Growth

New customer growth in the Company's natural gas distribution operations generated $1.5 million of additional margin, which was partially offset by $485,000 in lower margin due to fewer volumes sold to commercial and industrial customers in Florida and at Sandpiper. The details for the three months ended March 31, 2019 are provided in the following table:

(in thousands)	Three Months Ended March 31, 2019
Customer Growth:	
Residential	$ 637
Commercial and industrial, excluding new service in Northwest Florida	529
New service in Northwest Florida	285
Total Customer Growth	1,451
Non-Weather Change in Customer Consumption:	
Residential	(89)
Commercial and industrial	(396)
Total Decline in Customer Consumption	(485)
Total (or net) Increase in Natural Gas Distribution Margin	**$ 966**

The additional margin from new customers reflects an increase of approximately 3.9 percent in the average number of residential customers served on the Delmarva Peninsula, approximately 3.2 percent growth in new residential customers served in Florida, new service to customers in Northwest Florida, as well as an increase in the number of commercial and industrial customers served.

Propane Operations

Gross margin generated by our propane operations increased by $305,000 during the three months ended March 31, 2019, compared to the same period in 2018. The following table summarizes the year-over-year changes in gross margin for the propane business for the quarter ended March 31, 2019:

	Three Months Ended March 31, 2019
(in thousands)	
Decrease in customer consumption due to warmer weather	$ (1,307)
Increased retail margins per gallon	1,259
Customer growth, increased sales volumes (non-weather-related) and other factors	482
Ohl acquisition (assets acquired in December 2018)	476
Lower wholesale propane margins and sales	(453)
Other	(152)
2019 Change in gross margin by our propane operations	**$ 305**

Aspire Energy

Gross margin generated by Aspire Energy increased by $796,000 during the three months ended March 31, 2019, compared to the same period in 2018. The increase reflects $779,000 of rate increases and $397,000 of consumption growth, offset by a $380,000 decrease in gross margin due to various factors.

PESCO

PESCO's gross margin for the three months ended March 31, 2019 was higher by $685,000 compared to the same period in 2018. The following table summarizes the changes in PESCO's quarter-over-quarter margin for the three months ended March 31, 2019:

(in thousands)	Three Months Ended March 31, 2019
Net impact of PESCO's MTM activity	$ (5,591)
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [(1)]	3,284
Mid-Atlantic retail portfolio loss due to pipeline capacity constraints in the first quarter of 2018 [(1)]	2,261
Other margin for PESCO operations (net)	731
2019 Change in PESCO gross margin	**$ 685**

[(1)] The 2018 Bomb Cyclone refers to the high-intensity winter storms in early January 2018 that impacted the Mid-Atlantic region and had a residual impact on our businesses through the month of February 2018. The exceedingly high demand and associated impacts on pipeline capacity and gas supply in the Mid-Atlantic region created significant, unusual costs for PESCO. While such concerted impacts are not expected to occur frequently, our management revisited and refined its risk management strategies and implemented additional controls.

PESCO generated an operating loss of $510,000 for the three months ended March 31, 2019, compared to an operating loss of $764,000 during the prior year period. The improvement in the quarter-over-quarter results reflects higher gross margin growth, partially offset by a $431,000 increase in operating expenses for increased staffing, infrastructure and risk management system resources to support continued execution of PESCO's growth strategy.

Impact of Hurricane Michael

In October 2018, Hurricane Michael passed through FPU's electric distribution operation's service territory in Northwest Florida. The hurricane caused widespread and severe damage to FPU's infrastructure, resulting in 100 percent of its Northwest Florida customers losing electrical service. FPU, after exerting extraordinary hurricane restoration efforts, restored service to those customers who were able to accept it. Through March 31, 2019, FPU has spent approximately $65.0 million to restore service, which has been recorded as new plant and equipment or charged against FPU's accumulated depreciation and storm reserve. In conjunction with the hurricane-related expenditures, we executed two 13-month unsecured term loans as temporary financing, each in the amount of $30.0 million. The interest cost associated with these loans is LIBOR plus 75 basis points. One term loan was executed in December 2018; the other was executed in January 2019. The storm did not have a material impact on the margin from these operations, as services were restored to a majority of our customers. Pending the outcome of the regulatory filings associated with the storm, our results for the first quarter included higher interest expense of $435,000, or $326,000 on an after-tax basis, associated with the intermediate term loans discussed above. We are in the process of preparing the necessary regulatory filings to seek recovery of the costs incurred, including the associated interest costs.

Regulated Energy Segment

For the quarter ended March 31, 2019, compared to the quarter ended March 31, 2018:

	Three Months Ended March 31,		Increase
	2019	2018	(decrease)
(in thousands)			
Revenue	$ 103,618	$ 109,393	$ (5,775)
Cost of sales	36,516	48,231	(11,715)
Gross margin	67,102	61,162	5,940
Operations & maintenance	24,548	23,147	1,401
Depreciation & amortization	8,446	7,516	930
Other taxes	4,367	3,788	579
Other operating expenses	37,361	34,451	2,910
Operating income	$ 29,741	$ 26,711	$ 3,030

Operating income for the Regulated Energy segment for the three months ended March 31, 2019 was $29.7 million, an increase of $3.0 million compared to the same period in 2018. The increased operating income resulted from increased gross margin of $5.9 million, offset by $1.5 million in higher depreciation and taxes and a $1.4 million increase in operating expenses. On February 25, 2019, the Florida PSC issued a final order regarding the treatment of TCJA impact, allowing us to retain the savings associated with lower federal tax rates for certain of our natural gas distribution operations. As a result, $1.3 million in reserves for customer refunds, recorded in 2018, were reversed in 2019. Excluding the impact of the reversal, gross margin and operating income for the three months ended March 31, 2019 increased by $4.6 million and $1.7 million, or 7.6 percent and 6.4 percent, respectively.

Gross Margin

Items contributing to the quarter-over-quarter increase in gross margin are listed in the following table:

(in thousands)	Margin Impact
Eastern Shore and Peninsula Pipeline service expansions	$ 4,266
Natural gas distribution - customer growth (excluding service expansions)	1,451
2018 retained tax savings for certain Florida natural gas distribution operations	1,321
Impact of weather on customer consumption (primarily in Florida)	(1,093)
Natural gas distribution - change in customer consumption (non-weather)	(485)
Conversion of Sandpiper customers to natural gas	382
Florida GRIP	223
Other immaterial variances	(125)
Quarter-over-quarter increase in gross margin	**$ 5,940**

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Eastern Shore and Peninsula Pipeline Service Expansions

We generated additional gross margin of $4.3 million, primarily from the following natural gas service expansions:

- $2.5 million from Eastern Shore's services in conjunction with its 2017 Expansion Project.
- $1.5 million generated by Peninsula Pipeline from the Belvedere Pipeline and Northwest Pipeline Expansion Projects.

Natural Gas Customer Growth

We generated additional gross margin of $1.5 million from natural gas customer growth. Gross margin increased by $748,000 in Florida and $703,000 on the Delmarva Peninsula.

2018 retained tax savings for Florida natural gas operations

We generated additional gross margin of $1.3 million, due to a final order from the Florida PSC allowing us to retain the tax savings associated with TCJA. Pursuant to the order, refund reserves recorded by our Florida natural gas businesses in 2018, were reversed in 2019. See Note 4, *Rates and Other Regulatory Activities*, for additional information.

Impact of Weather on Customer Consumption
Gross margin decreased by $1.1 million, as weather in Florida was approximately 26 percent warmer in the first quarter of 2019, compared to the same period in 2018. This reduced consumption by Florida electric and natural gas distribution customers, decreasing gross margin by approximately $784,000. Our Delmarva natural gas operations experienced a decrease in margin of $310,000, reflecting the absence, during the first quarter of 2019, of the much higher consumption experienced during the first quarter of 2018 due to the extreme Bomb Cyclone weather conditions.

Consumption Changes (non-weather)
Gross margin decreased by $485,000 due to non-weather-related decreases in customer sales volumes in Florida and on the Delmarva Peninsula.

Sandpiper's margin from natural gas conversions
Gross margin increased by $382,000, due primarily to continuing conversion of the Sandpiper system from propane service to natural gas service.

Florida GRIP
Continued investment in the Florida GRIP generated additional gross margin of $223,000 for the three months ended March 31, 2019, compared to the same period in 2018.

Other Operating Expenses
Items contributing to the quarter-over-quarter increase in operating expenses are listed in the following table:

(in thousands)	Other Operating Expenses
Depreciation, amortization and property taxes primarily associated with recent growth projects	$ 1,375
Incentive compensation costs (based on timing and period-over-period results)	653
Outside services, facilities and maintenance costs	(609)
Payroll expense (increased staffing and annual salary increases)	608
Benefits and other employee-related expenses[1]	551
Other immaterial variances	332
Quarter-over-quarter increase in other operating expenses	**$ 2,910**

[1] Since we self-insure for healthcare costs, benefits costs fluctuate depending upon filed claims.

Unregulated Energy Segment

For the quarter ended March 31, 2019, compared to the quarter ended March 31, 2018:

	Three Months Ended March 31,		Increase
	2019	2018	(decrease)
(in thousands)			
Revenue	**$ 138,102**	$ 145,367	$ (7,265)
Cost of sales	**103,700**	115,066	(11,366)
Gross margin	**34,402**	30,301	4,101
Operations & maintenance	**15,555**	13,359	2,196
Depreciation & amortization	**2,611**	2,167	444
Other taxes	**1,109**	1,091	18
Total operating expenses	**19,275**	16,617	2,658
Operating income	**$ 15,127**	$ 13,684	$ 1,443

The Unregulated Energy segment had operating income of $15.1 million and $13.7 million for the three months ended March 31, 2019 and 2018, respectively. The increased operating income of approximately $1.4 million was due to an increase in gross margin of $4.1 million, partially offset by a $2.7 million increase in operating expenses.

Unregulated Energy, excluding PESCO

For the Three Months Ended March 31,	2019	2018	Increase (decrease)
(in thousands)			
Gross margin	$ 32,542	$ 29,126	$ 3,416
Depreciation, amortization and property taxes	2,792	2,357	435
Other operating expenses	14,113	12,321	1,792
Operating Income	$ 15,637	$ 14,448	$ 1,189

Gross Margin

Items contributing to the quarter-over-quarter increase in gross margin are listed in the following table:

(in thousands)	Margin Impact
Marlin Gas Services (acquired assets of Marlin Gas Transport in December 2018)	$ 2,329
Propane Operations	
Decrease in weather-related customer consumption due to the absence of the 2018 Bomb Cyclone	(1,307)
Increased retail margins per gallon	1,259
Customer growth, increased sales volumes (non-weather-related) and other factors	482
Ohl acquisition (assets acquired in December 2018)	476
Lower wholesale propane margins and sales	(453)
Aspire Energy	
Rate increases	779
Increased customer consumption	397
Other immaterial variances	(546)
Quarter-over-quarter increase in gross margin	**$ 3,416**

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Marlin Gas Services
Gross margin increased by $2.3 million as a result of the acquisition of certain assets of Marlin Gas Transport in December 2018.

Propane Operations - Decreased Customer Consumption - (Weather)
While HDDs were essentially flat period-over-period on the Delmarva Peninsula, extreme conditions during the January 2018 "Bomb Cyclone" drove weather-related consumption in the first quarter of 2018 compared to the same period in 2019, and which reduced gross margin by $1.1 million for the Delmarva propane operations. Weather in Florida was approximately 26 percent warmer in the first quarter of 2019 reducing consumption by propane distribution customers and decreasing gross margin by approximately $167,000, compared to the same period in 2018.

Propane Operations - Increased Retail Margins Per Gallon
Gross margin increased by $1.3 million, due to lower propane costs during the first quarter of 2019, compared to the same period in 2018. Our retail pricing strategy, guided by local market conditions, further increased margins in the first quarter of 2019. These market conditions, which 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.

Aspire Energy - Increased Margin Driven by Changes in Rates
Gross margin increased by $779,000, due primarily to changes in customer rates on various dates during 2018.

Aspire Energy - Increased Margin Driven by Growth in Customer Consumption
Gross margin increased by $397,000, due to an increase in customer consumption during the first quarter of 2019, compared to the same period in 2018.

Propane Operations - Increased Margin Driven by Growth and Other Factors
Gross margin increased by $482,000, due to increased propane sales as a result of customer growth and other factors in Florida and the Mid-Atlantic region.

Propane Operations - Ohl Acquisition
Gross margin increased by $476,000 as a result of the acquisition of R.F. Ohl in December 2018, which was rolled into Sharp.

Wholesale Propane Margins
Gross margin decreased by $453,000 in 2019 due to a lower margin per gallon and a decrease in volumes delivered for the Mid-Atlantic propane operations.

Other Operating Expenses

Other operating expenses increased by $2.2 million in the first quarter of 2019. The significant components of the increase in other operating expenses included:

(in thousands)	Other Operating Expenses
Operating expenses associated with operating Marlin Gas Services and Ohl (Asset acquisitions in December 2018)	$ 1,157
Incentive compensation costs (based on timing and period-over-period results)	466
Outside services and facilities maintenance costs	286
Depreciation, asset removal and property tax costs due to new capital investments	187
Benefits and other employee-related expenses[1]	133
Other immaterial variances	(2)
Quarter-over-quarter increase in other operating expenses	**$ 2,227**

[1] Since the Company self-insures for healthcare costs, benefits costs fluctuate depending upon filed claims.

PESCO

For the Three Months Ended March 31,	**2019**	**2018**	**Increase (decrease)**
(in thousands)			
Gross margin	**$ 1,860**	$ 1,175	$ 685
Depreciation, amortization and property taxes	**147**	148	(1)
Other operating expenses	**2,223**	1,791	432
Operating Income	**$ (510)**	$ (764)	$ 254

For the three months ended March 31, 2019, PESCO's gross margin increased by $685,000 compared to the same period in 2018. Higher gross margin from PESCO for the three months ended March 31, 2019 resulted from the following:

(in thousands)	Margin Impact
Net impact of PESCO's MTM activity	$ (5,591)
Net impact of extraordinary costs associated with the 2018 Bomb Cyclone for the Mid-Atlantic wholesale portfolio [1]	3,284
Mid-Atlantic retail portfolio loss due to pipeline capacity constraints in the first quarter of 2018 [1]	2,261
Other margin for PESCO operations (net)	731
Quarter-over-quarter increase in gross margin for PESCO	**$ 685**

[1] The 2018 Bomb Cyclone refers to the high-intensity winter storms in early January 2018 that impacted the Mid-Atlantic region and had a residual impact on our businesses through the month of February. The exceedingly high demand and associated impacts on pipeline capacity and gas supply in the Mid-Atlantic region created significant, unusual costs for PESCO. While such concerted impacts are not expected to occur frequently, our management revisited and refined its risk management strategies and implemented additional controls.

Operating expenses increased by $432,000, reflecting increased staffing, infrastructure and risk management systems necessary to support growth. Overall, PESCO's quarter-over-quarter performance improved by $254,000.

OTHER INCOME (EXPENSE), NET

For the quarter ended March 31, 2019 compared to the quarter ended March 31, 2018

Other income (expense), net, which includes non-operating investment income (expense), interest income, late fees charged to customers, gains or losses from the sale of assets and pension and other benefits expense, decreased by $113,000 in the first quarter of 2019, compared to the same period in 2018.

INTEREST CHARGES

For the quarter ended March 31, 2019 compared to the quarter ended March 31, 2018

Interest charges for the three months ended March 31, 2019 increased by $2.0 million, compared to the same period in 2018, attributable primarily to an increase of $980,000 in interest on higher levels of short-term borrowings, and an increase of $742,000 in interest on long-term debt, largely as a result of the issuance of the NYL Shelf Notes in May and November 2018 and term notes issued in December 2018 and January 2019 to finance the restoration of service to customers who lost service due to the impact of Hurricane Michael.

INCOME TAXES

For the quarter ended March 31, 2019 compared to the quarter ended March 31, 2018

Income tax expense was $9.6 million for the three months ended March 31, 2019, compared to $10.0 million in the same period in 2018. The decrease in income tax expense was attributed to the amortization of deferred taxes gross up associated with TCJA. Our effective income tax rate was 25.0 percent and 27.0 percent, for the three months ended March 31, 2019 and 2018, respectively.

FINANCIAL POSITION, 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 with our target capital structure.

Our energy businesses are weather-sensitive and seasonal. We normally generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas, electricity, and propane delivered by our distribution operations, and our natural gas gathering and processing operation to customers during the peak heating season. In addition, our natural gas and propane inventories, which usually peak in the fall months, are largely drawn down in the heating season and provide a source of cash as the inventory is used to satisfy winter sales demand.

Capital expenditures for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures were $33.8 million for the three months ended March 31, 2019.

The following table shows the 2019 capital expenditure budget of $168.2 million by segment and by business line:

(dollars in thousands)	2019
Regulated Energy:	
Natural gas distribution	$ 64,143
Natural gas transmission	66,787
Electric distribution	5,949
Total Regulated Energy	136,879
Unregulated Energy:	
Propane distribution	11,870
Energy transmission	8,345
Other unregulated energy	1,416
Total Unregulated Energy	21,631
Other:	
Corporate and other businesses	9,705
Total Other	9,705
Total 2019 Budgeted Capital Expenditures	$ 168,215

The 2019 budget, excluding acquisitions, includes: Eastern Shore's 2017 Expansion Project and Del-Mar Energy Pathway Project, Florida's Palm Beach County Western Expansion and other potential pipeline projects, continued expenditures under Florida GRIP, further expansions of our natural gas distribution and transmission systems, continued natural gas infrastructure improvement activities, information technology systems, new buildings and facilities, and other strategic initiatives and investments.

The capital expenditure projection is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts.

The timing of capital expenditures can vary based on delays in regulatory approvals, securing environmental approvals and other permits. The regulatory application and approval process has lengthened in the past few years, and we expect this trend to continue.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated energy operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost, which will benefit our customers, creditors, employees and stockholders.

The following table presents our capitalization, excluding and including short-term borrowings, as of March 31, 2019 and December 31, 2018:

	March 31, 2019		December 31, 2018	
(in thousands)				
Long-term debt, net of current maturities	$ 285,998	34%	$ 316,020	38%
Stockholders' equity	543,659	66%	518,439	62%
Total capitalization, excluding short-term debt	$ 829,657	100%	$ 834,459	100%

	March 31, 2019		December 31, 2018	
(in thousands)				
Short-term debt	$ 276,393	24%	$ 294,458	26%
Long-term debt, including current maturities	357,507	30%	327,955	29%
Stockholders' equity	543,659	46%	518,439	45%
Total capitalization, including short-term debt	$ 1,177,559	100%	$ 1,140,852	100%

Included in the long-term debt balances at March 31, 2019 and December 31, 2018, were finance lease obligations for Sandpiper and Sharp. Sandpiper entered into a capacity, supply and operating agreement which expires in May 2019. The capacity portion of this agreement is accounted for as a finance lease. At March 31, 2019 and December 31, 2018, the remaining balance of $249,000 and $620,000, respectively, was included in current maturities.

Sharp had previously entered into an agreement to rent property in Anne Arundel County, Maryland, which it subsequently acquired in April 2019 (at March 31, 2019, $660,000 of current maturities and at December 31, 2018, $690,000 of current maturities).

Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. Including the funds expended specifically related to the impact of Hurricane Michael, our equity to total capitalization ratio, including short-term borrowings, was 46.0 percent as of March 31, 2019. Excluding the funds expended for Hurricane Michael restoration activities, our equity to total capitalization ratio, including short-term borrowings, would have been approximately 49 percent. The Company seeks to align permanent financing with the in-service dates of its capital projects. The Company may utilize more temporary short-term debt when the financing cost is attractive as a bridge to the permanent long-term financing.

Term Notes

In December 2018, we issued a $30.0 million unsecured term note through PNC Bank N.A. with maturity of January 21, 2020. The interest rate at March 31, 2019 and December 31, 2018 was 3.24% and 3.23%, respectively, which equals one month LIBOR rate plus 75 basis points. In January 2019, we issued a $30.0 million unsecured term note through Branch Banking and Trust Company, with maturity of February 28, 2020. The interest rate at March 31, 2019 was 3.24% which equals one month LIBOR rate plus 75 basis points. These term notes totaling $60.0 million are included in the current maturities of long-term debt as of March 31, 2019.

Shelf Agreements

We have entered into Shelf Agreements with Prudential, MetLife and NYL who are under no obligation to purchase any unsecured debt. The proceeds received from the issuances of these shelf notes was used to reduce borrowings under the Revolver and/or lines of credit and/or to fund capital expenditures. We entered into the Prudential Shelf Agreement, totaling $150.0 million, in October 2015, and we issued $70.0 million of 3.25% unsecured debt in April 2017. The Prudential Shelf Agreement was then amended in September 2018 to increase the borrowing capacity back up to $150.0 million, and Prudential accepted our request to purchase our unsecured debt of $100.0 million at an interest rate of 3.98% on or before August 20, 2019. We entered into the NYL Shelf Agreement, totaling $100.0 million, in March 2017, and we issued unsecured debt totaling $100.0 million during 2018. The NYL Shelf Agreement was amended in November 2018 to add incremental borrowing capacity of $50.0 million. As of March 31, 2019, we had not requested that MetLife purchase unsecured senior debt under the MetLife Shelf Agreement, which we entered into in March 2017. The following table summarizes our shelf agreements borrowing information at March 31, 2019:

(in thousands)	Total Borrowing Capacity	Less: Amount of Debt Issued	Less: Unfunded Commitments	Remaining Borrowing Capacity
Shelf Agreement				
Prudential Shelf Agreement	$ 220,000	$ (70,000)	$ (100,000)	$ 50,000
MetLife Shelf Agreement	150,000	—	—	150,000
NYL Shelf Agreement	150,000	(100,000)	—	50,000
Total	$ 520,000	$ (170,000)	$ (100,000)	$ 250,000

The Shelf Agreements or Shelf Notes set forth certain business covenants to which we are subject when any note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

Short-term Borrowings

Our outstanding short-term borrowings at March 31, 2019 and December 31, 2018 were $276.4 million and $294.5 million at weighted average interest rates of 3.75 percent and 3.44 percent, respectively. Our current short-term borrowing limit, authorized by our Board of Directors, is $370.0 million.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. As of March 31, 2019, we had five unsecured bank credit facilities with four financial institutions totaling $220.0 million in available credit. In addition, we have a $150.0 million Revolver under which borrowings can be designated as short-term debt. The terms of the Revolver are further described below. None of the unsecured bank lines of credit requires compensating balances.

The $150.0 million Revolver is available through October 8, 2020 and is subject to the terms and conditions set forth in the credit agreement among us and the lenders related to the Revolver ("Credit Agreement"). Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures. Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25 percent or less. Interest is payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We have the right, under certain circumstances, to extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the lenders' approval. We may also request the lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each lender.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the three months ended March 31, 2019 and 2018:

	Three Months Ended March 31,	
(in thousands)	2019	2018
Net cash provided by (used in):		
Operating activities	$ 40,486	$ 66,672
Investing activities	(43,369)	(62,971)
Financing activities	4,769	(3,319)
Net increase in cash and cash equivalents	1,886	382
Cash and cash equivalents—beginning of period	6,089	5,614
Cash and cash equivalents—end of period	$ 7,975	$ 5,996

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.

During the three months ended March 31, 2019 and 2018, net cash provided by operating activities was $40.5 million and $66.7 million, respectively, resulting in a decrease in cash flows of $26.2 million. Significant operating activities generating the cash flows change were as follows:

- Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities decreased cash flows by $9.4 million, due primarily to the timing and receipt of payments.
- Changes in net regulatory assets and liabilities decreased cash flows by $8.4 million, due primarily to the change in fuel costs collected through the various cost recovery mechanisms.
- Net cash flows from changes in propane inventory, storage gas and other inventories decreased by approximately $5.2 million due primarily to lower levels of our inventory during 2018.
- Net income, adjusted for reconciling activities, decreased cash flows by $5.4 million, primarily due to the absence of deferred tax assets pertaining to the availability and utilization of bonus depreciation during 2018, offset by an increase in net income and higher non-cash adjustments for depreciation and amortization related to increased investing activities.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $43.4 million and $63.0 million during the three months ended March 31, 2019 and 2018, respectively, resulting in an increase in cash of $19.6 million. Cash paid for capital expenditures decreased by $19.9 million to $43.2 million for the first three months of 2019, compared to $63.1 million for the same period in 2018.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities totaled $4.8 million during the three months ended March 31, 2019 compared to net cash of $3.3 million used in financing activities during the prior year period resulting in an increase in cash flows of $8.1 million. The increase in net cash provided by financing activities resulted primarily from the following:

- Increased cash flows of $5.0 million as a result of $30.0 million in proceeds from a term note issued in January 2019. During the three months ended March 31, 2018, we received $25.0 million in proceeds from the Revolver, which was advanced on a long-term basis.
- Increased cash flows from lower repayments of short-term borrowing of $6.1 million under our line of credit arrangements.
- Decreased cash flows of $2.3 million as a result of changes in cash overdrafts and;
- Cash dividends of $5.9 million paid during the three months ended March 31, 2019, compared to $5.1 million for the three months ended March 31, 2018.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries that provide for the payment of propane and natural gas purchases in the event of the subsidiary's default. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at March 31, 2019 was $77.3 million, with the guarantees expiring on various dates through December 2020.

We have issued letters of credit totaling $7.0 million related to the electric transmission services for FPU's northwest electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, and to our current and previous primary insurance carriers with expiration dates extending through March 2020. There were no draws on these letters of credit as of March 31, 2019. 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 Note 6, *Other Commitments and Contingencies* in the condensed consolidated financial statements.

Contractual Obligations

There has been no material change in the contractual obligations presented in our 2018 Annual Report on Form 10-K, except for long-term debt and commodity purchase obligations entered into in the ordinary course of our business. The following table summarizes long-term debt and commodity purchase contract obligations at March 31, 2019:

	Payments Due by Period				
(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Long-term debt [1]	$ 70,600	$ 29,200	$ 45,700	$ 211,700	**$ 357,200**
Purchase obligations - Commodity [2]	112,947	34,384	13,483	11,762	**172,576**
Total	**$ 183,547**	**$ 63,584**	**$ 59,183**	**$ 223,462**	**$ 529,776**

[1] Excludes finance lease obligation, debt issuance costs and an unamortized discount of $307,000.

[2] In addition to the obligations noted above, we have agreements with commodity suppliers that have provisions with no minimum purchase requirements. There are no monetary penalties for reducing the amounts purchased; however, the propane contracts allow the suppliers to reduce the amounts available in the winter season if we do not purchase specified amounts during the summer season. Under these contracts, the commodity prices will fluctuate as market prices fluctuate.

Rates and Regulatory Matters

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by the respective state PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At March 31, 2019, we were involved in regulatory matters in each of the jurisdictions in which we operate. Our significant regulatory matters are fully described in Note 4, *Rates and Other Regulatory Activities*, to the condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Recent Authoritative Pronouncements on Financial Reporting and Accounting

Recent accounting developments applicable to us and their impact on our financial position, results of operations and cash flows are described in Note 1, *Summary of Accounting Policies*, to the condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Interest Rate Risk

Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt at March 31, 2019, consists of fixed-rate Senior Notes and $8.0 million of fixed-rate secured debt. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowings based in part on the fluctuation in interest rates. Additional information about our long-term debt is disclosed in Note 14, *Long-term Debt,* in the condensed consolidated financial statements.

Commodity Price Risk

Regulated Energy Segment

We have entered into agreements with various wholesale suppliers to purchase natural gas and electricity for resale to our customers. Our regulated energy distribution businesses that sell natural gas or electricity to end-use customers have fuel cost recovery mechanisms authorized by the PSCs that allow us to recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers. Therefore, our regulated energy distribution operations have limited commodity price risk exposure.

Unregulated Energy Segment

Our propane operations are exposed to commodity price risk as a result of the competitive nature of retail pricing offered to our customers. In order to mitigate this risk, we utilize propane storage activities and forward contracts for supply.

We can store up to approximately 7 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate the risk of propane commodity price fluctuations on the inventory valuation, we have adopted a Risk Management Policy that allows our propane distribution operation to enter into fair value hedges, cash flow hedges or other economic hedges of our inventory.

Aspire Energy is exposed to commodity price risk, primarily during the winter season, to the extent we are not successful in balancing our natural gas purchases and sales and have to secure natural gas from alternative sources at higher spot prices. In order to mitigate this risk, we procure firm capacity that meets our estimated volume requirements and we continue to seek out new producers in order to fulfill our natural gas purchase requirements.

PESCO is a party to natural gas swap and futures contracts, which provide us the right to purchase natural gas at a fixed price at future dates. Upon expiration, the contracts can be settled financially without taking delivery of natural gas, or PESCO can procure natural gas and deliver it to its customers. PESCO is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids and natural gas deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts.

The following table reflects the changes in the fair market value of financial derivatives contracts related to natural gas and propane purchases and sales from December 31, 2018 to March 31, 2019:

(in thousands)	Balance at December 31, 2018	Increase (Decrease) in Fair Market Value	Less Amounts Settled	Balance at March 31, 2019
PESCO	$ (184)	$ 3,807	$ (617)	**$ 3,006**
Sharp	(1,522)	354	585	**(583)**
Total	$ (1,706)	$ 4,161	$ (32)	**$ 2,423**

There were no changes in methods of valuations during the three months ended March 31, 2019.

The following is a summary of fair market value of financial derivatives as of March 31, 2019, by method of valuation and by maturity for each fiscal year period.

(in thousands)	2019	2020	2021	2022	Total Fair Value
Price based on ICE - PESCO	$ 18	$ 2,091	$ 848	$ 49	$ 3,006
Price based on Mont Belvieu - Sharp	(386)	(161)	(36)	—	(583)
Total	$ (368)	$ 1,930	$ 812	$ 49	$ 2,423

WHOLESALE CREDIT RISK

The Risk Management Committee reviews credit risks associated with counterparties to commodity derivative contracts prior to such contracts being approved.

Additional information about our derivative instruments is disclosed in Note 12, *Derivative Instruments,* in the condensed consolidated financial statements.

INFLATION

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we periodically seek rate increases from regulatory commissions for our regulated operations and closely monitor the returns of our unregulated energy business operations. To compensate for fluctuations in propane gas prices, we adjust propane sales prices to the extent allowed by the market.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of Chesapeake Utilities, with the participation of other Company officials, have evaluated our "disclosure controls and procedures" (as such term is defined under Rules 13a-15(e) and 15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of March 31, 2019. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2019.

Changes in Internal Control over Financial Reporting

Beginning January 1, 2019, we adopted ASU 2016-02, *Leases*. The impacts of the adoption are discussed in detail in Note 1, Summary of Accounting Policies, and Note 15, Leases, in the notes to the condensed consolidated financial statements within this Form 10-Q. In conjunction with this adoption, we implemented changes to our controls related to leases, which were not material to our internal controls over financial reporting. These included the development of new policies for the identification of leases and other ongoing monitoring activities. These controls were designed to provide assurance, at a reasonable level, of the fair presentation of our condensed consolidated financial statements and related disclosures. During the quarter ended March 31, 2019, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 6, *Other Commitments and Contingencies*, of the condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we are involved in certain legal actions and claims arising in the normal course of business. We are also involved in certain legal and administrative proceedings before various governmental or regulatory agencies concerning rates and other regulatory actions. In the opinion of management, the ultimate disposition of these proceedings and claims will not have a material effect on our condensed consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

Our business, operations, and financial condition are subject to various risks and uncertainties. The risk factors described in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K, for the year ended December 31, 2018, should be carefully considered, together with the other information contained or incorporated by reference in this Quarterly Report on Form 10-Q and in our other filings with the SEC in connection with evaluating Chesapeake Utilities, our business and the forward-looking statements contained in this Quarterly Report on Form 10-Q. Additional risks and uncertainties not known to us at present, or that we currently deem immaterial, also may affect Chesapeake Utilities. The occurrence of any of these known or unknown risks could have a material adverse impact on our business, financial condition and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

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]
January 1, 2019 through January 31, 2019 [1]	388	$ 81.65	—	—
February 1, 2019 through February 28, 2019	—	$ —	—	—
March 1, 2019 through March 31, 2019	—	$ —	—	—
Total	388	$ 81.65	—	—

[1] Chesapeake Utilities 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 under the heading "Notes to the Consolidated Financial Statements—Note 9, *Employee Benefit Plans*" in our latest Annual Report on Form 10-K for the year ended December 31, 2018. During the quarter ended March 31, 2019, 388 shares were purchased through the reinvestment of dividends on deferred stock units.

[2] Except for the purposes described in Footnote (1), Chesapeake Utilities has no publicly announced plans or programs to repurchase its shares.

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

Item 6. Exhibits

10.1*	Term Note issued by Chesapeake Utilities Corporation in favor of Branch Banking and Trust Company on January 31, 2019.
10.2*	Term Loan Credit Agreement, dated January 31, 2019, by and between Chesapeake Utilities Corporation and Branch Banking and Trust Company.
31.1*	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32.1*	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
32.2*	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

*Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

/S/ BETH W. COOPER

Beth W. Cooper
Executive Vice President, Chief Financial Officer, and Assistant Corporate Secretary

Date: May 8, 2019