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

FORM 10-Q

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

For the quarterly period ended: September 30, 2017

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

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)

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 x 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 x No ☐

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

Large accelerated filer	x	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

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

Common Stock, par value $0.4867 — 16,344,442 shares outstanding as of October 31, 2017.

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GLOSSARY OF DEFINITIONS

ARM: ARM Energy Management, LLC, a natural gas supply and supply management company servicing commercial and industrial customers in Western Pennsylvania, which sold certain natural gas marketing 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

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

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

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

CIAC: Contributions from customers that are used to construct facilities

CGC: Consumer Gas Cooperative, an Ohio natural gas cooperative

CHP: Combined heat and power plant

Columbia Gas: Columbia Gas of Ohio, an unaffiliated local distribution company based in Ohio

Company: Chesapeake Utilities Corporation, and its direct and indirect 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

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

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

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 natural gas transmission subsidiary of Chesapeake Utilities

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

Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake OnSight Services, LLC, which owns and operates a CHP plant on Amelia Island, Florida

EPA: United States Environmental Protection Agency

ESG: Eastern Shore Gas Company and its affiliates

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

FGT: Florida Gas Transmission Company

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

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

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

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

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

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

Gulf Power: Gulf Power Company, an unaffiliated electric company that 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

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 in March 2017 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

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

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

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 in March 2017 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

OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a tariff associated with Eastern Shore's firm transportation service that enables Eastern Shore to forgo scheduling service for up to 90 days during the peak months of November through April each year

OTC: Over-the-counter

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

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

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

Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the 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 that we may request Prudential to purchase under the Prudential Shelf Agreement

PSC: Public Service Commission, which is the state agency that regulates the rates and 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

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

Revolver: Our unsecured revolving credit facility with the Lenders

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

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

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

SICP: 2013 Stock and Incentive Compensation Plan

TETLP: Texas Eastern Transmission, LP, 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—FINANCIAL INFORMATION

Item 1. Financial Statements

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated Energy	**$ 69,703**	$ 70,019	**$ 238,353**	$ 226,630
Unregulated Energy and other	**57,233**	38,329	**198,827**	130,356
Total Operating Revenues	**126,936**	108,348	**437,180**	356,986
Operating Expenses				
Regulated Energy cost of sales	**22,794**	24,644	**87,206**	81,184
Unregulated Energy and other cost of sales	**44,066**	28,183	**145,325**	85,142
Operations	**29,667**	30,126	**92,990**	85,370
Maintenance	**2,737**	3,542	**9,370**	8,925
Gain from a settlement	**—**	—	**(130)**	(130)
Depreciation and amortization	**9,362**	8,209	**27,267**	23,493
Other taxes	**4,071**	3,488	**12,572**	10,725
Total Operating Expenses	**112,697**	98,192	**374,600**	294,709
Operating Income	**14,239**	10,156	**62,580**	62,277
Other income (expense), net	**239**	(28)	**(643)**	(68)
Interest charges	**3,321**	2,722	**9,133**	7,996
Income Before Income Taxes	**11,157**	7,406	**52,804**	54,213
Income taxes	**4,324**	2,990	**20,781**	21,401
Net Income	**$ 6,833**	$ 4,416	**$ 32,023**	$ 32,812
Weighted Average Common Shares Outstanding:				
Basic	**16,344,442**	15,372,413	**16,334,210**	15,324,932
Diluted	**16,389,635**	15,412,783	**16,378,633**	15,365,955
Earnings Per Share of Common Stock:				
Basic	**$ 0.42**	$ 0.29	**$ 1.96**	$ 2.14
Diluted	**$ 0.42**	$ 0.29	**$ 1.96**	$ 2.14
Cash Dividends Declared Per Share of Common Stock	**$ 0.3250**	$ 0.3050	**$ 0.9550**	$ 0.8975

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
(in thousands)				
Net Income	**$ 6,833**	$ 4,416	**$ 32,023**	$ 32,812
Other Comprehensive (Loss) Income, net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of $(8), $(8), $(23) and $(23), respectively	**(11)**	(12)	**(35)**	(37)
Net gain, net of tax of $69, $66, $212 and $200, respectively	**102**	100	**297**	300
Cash Flow Hedges, net of tax:				
Unrealized (loss)/gain on commodity contract cash flow hedges, net of tax of $(15), $38, $(376) and $360, respectively	**(104)**	51	**(643)**	548
Total Other Comprehensive (Loss) Income	**(13)**	139	**(381)**	811
Comprehensive Income	**$ 6,820**	$ 4,555	**$ 31,642**	$ 33,623

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Assets	September 30, 2017	December 31, 2016
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	$ 1,050,332	$ 957,681
Unregulated Energy	207,331	196,800
Other businesses and eliminations	26,061	21,114
Total property, plant and equipment	1,283,724	1,175,595
Less: Accumulated depreciation and amortization	(267,138)	(245,207)
Plus: Construction work in progress	69,053	56,276
Net property, plant and equipment	1,085,639	986,664
Current Assets		
Cash and cash equivalents	3,386	4,178
Accounts receivable (less allowance for uncollectible accounts of $912 and $909, respectively)	52,775	62,803
Accrued revenue	14,307	16,986
Propane inventory, at average cost	5,226	6,457
Other inventory, at average cost	12,711	4,576
Regulatory assets	9,761	7,694
Storage gas prepayments	6,876	5,484
Income taxes receivable	26,741	22,888
Prepaid expenses	10,899	6,792
Derivative assets, at fair value	1,526	823
Other current assets	4,797	2,470
Total current assets	149,005	141,151
Deferred Charges and Other Assets		
Goodwill	21,944	15,070
Other intangible assets, net	4,608	1,843
Investments, at fair value	6,380	4,902
Regulatory assets	75,793	76,803
Receivables and other deferred charges	3,381	2,786
Total deferred charges and other assets	112,106	101,404
Total Assets	$ 1,346,750	$ 1,229,219

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities	September 30, 2017	December 31, 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 $0.4867 per share (authorized 25,000,000 shares)	**7,955**	7,935
Additional paid-in capital	**252,722**	250,967
Retained earnings	**208,402**	192,062
Accumulated other comprehensive loss	**(5,259)**	(4,878)
Deferred compensation obligation	**3,366**	2,416
Treasury stock	**(3,366)**	(2,416)
Total stockholders' equity	**463,820**	446,086
Long-term debt, net of current maturities	**201,248**	136,954
Total capitalization	**665,068**	583,040
Current Liabilities		
Current portion of long-term debt	**12,136**	12,099
Short-term borrowing	**203,098**	209,871
Accounts payable	**53,284**	56,935
Customer deposits and refunds	**32,493**	29,238
Accrued interest	**3,361**	1,312
Dividends payable	**5,312**	4,973
Accrued compensation	**8,544**	10,496
Regulatory liabilities	**5,338**	1,291
Derivative liabilities, at fair value	**1,732**	773
Other accrued liabilities	**13,972**	7,063
Total current liabilities	**339,270**	334,051
Deferred Credits and Other Liabilities		
Deferred income taxes	**252,273**	222,894
Regulatory liabilities	**42,915**	43,064
Environmental liabilities	**8,382**	8,592
Other pension and benefit costs	**32,059**	32,828
Deferred investment tax credits and other liabilities	**6,783**	4,750
Total deferred credits and other liabilities	**342,412**	312,128
Environmental and other commitments and contingencies (Note 4 and 5)		
Total Capitalization and Liabilities	**$ 1,346,750**	$ 1,229,219

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Cash Flows (Unaudited)

	Nine Months Ended September 30,	
(in thousands)	**2017**	**2016**
Operating Activities		
Net income	**$ 32,023**	$ 32,812
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**27,267**	23,493
Depreciation and accretion included in other costs	**5,989**	5,357
Deferred income taxes	**29,520**	12,004
Realized gain on commodity contracts/sale of assets/investments	**(2,817)**	(405)
Unrealized gain on investments/commodity contracts	**(695)**	(243)
Employee benefits and compensation	**1,212**	1,217
Share-based compensation	**1,608**	1,887
Other, net	**(39)**	42
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	**12,912**	(3,835)
Propane inventory, storage gas and other inventory	**(8,256)**	(2,179)
Regulatory assets/liabilities, net	**927**	(3,326)
Prepaid expenses and other current assets	**(2,860)**	485
Accounts payable and other accrued liabilities	**4,515**	7,187
Income taxes (payable) receivable	**(3,810)**	14,897
Customer deposits and refunds	**3,255**	(314)
Accrued compensation	**(2,030)**	(2,293)
Other assets and liabilities, net	**(349)**	(1,053)
Net cash provided by operating activities	**98,372**	85,733
Investing Activities		
Property, plant and equipment expenditures	**(130,137)**	(109,589)
Proceeds from sales of assets	**601**	119
Acquisitions, net of cash acquired	**(11,707)**	—
Environmental expenditures	**(210)**	(260)
Net cash used in investing activities	**(141,453)**	(109,730)
Financing Activities		
Common stock dividends	**(14,780)**	(12,964)
Issuance of stock for Dividend Reinvestment Plan	**254**	600
Stock issuance	**(10)**	57,306
Tax withholding payments related to net settled stock compensation	**(692)**	(770)
Change in cash overdrafts due to outstanding checks	**(3,013)**	2,466
Net repayment under line of credit agreements	**(3,760)**	(21,379)
Proceeds from issuance of long-term debt	**69,800**	—
Repayment of long-term debt and capital lease obligation	**(5,510)**	(2,581)
Net cash provided by financing activities	**42,289**	22,678
Net Decrease in Cash and Cash Equivalents	**(792)**	(1,319)
Cash and Cash Equivalents—Beginning of Period	**4,178**	2,855
Cash and Cash Equivalents—End of Period	**$ 3,386**	$ 1,536

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

Chesapeake Utilities Corporation and Subsidiaries

Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

	Common Stock (1)							
(in thousands, except shares and per share data)	Number of Shares(2)	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total (2)
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
Dividend 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	—	—	—	—	—	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	—	—	—	32,023	—	—	—	32,023
Other comprehensive loss	—	—	—	—	(381)	—	—	(381)
Dividend declared ($0.9550 per share)	—	—	—	(15,683)	—	—	—	(15,683)
Dividend reinvestment plan	10,771	5	731	—	—	—	—	736
Stock issuance	—	—	(10)	—	—	—	—	(10)
Share-based compensation and tax benefit (4) (5)	30,172	15	1,034	—	—	—	—	1,049
Treasury stock activities	—	—	—	—	—	950	(950)	—
Balance at September 30, 2017	**16,344,442**	**$ 7,955**	**$ 252,722**	**$ 208,402**	**$ (5,259)**	**$ 3,366**	**$ (3,366)**	**$ 463,820**

(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 90,588 and 76,745 shares at September 30, 2017 and December 31, 2016, respectively, held in a Rabbi Trust related to our 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 the nine months ended September 30, 2017, and for the year ended December 31, 2016, we withheld 10,269 and 12,031 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, 2016. 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.

We reclassified certain amounts in the condensed consolidated statement of cash flows for the nine months ended September 30, 2016 to conform to the current year’s presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

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. The acquired assets complement PESCO’s current asset portfolio and will 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 payment of contingent consideration to ARM. 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 business 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 Jackson, Calhoun, Gadsden, Liberty, Bay and Washington Counties, Florida.

The revenue and net income from these acquisitions that we included in our condensed consolidated statements of income for the three and nine months ended September 30, 2017, were not material. The amounts recorded in conjunction with our acquisitions are preliminary and subject to adjustment based on additional valuations performed during the measurement period.

FASB Statements and Other Authoritative Pronouncements

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 will continue assessing the impact on our financial position, results of operations and cash flows during the fourth quarter of 2017. 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. In the third quarter of 2017, we began providing additional training to our employees and implementing system and process changes that are associated with the adoption of the standard. We plan to utilize the modified retrospective transition method upon adoption of this standard.

Based on our current assessment, we believe that the implementation of this new standard will not have a material impact on the amount and timing of revenue recognition except for one long-term contract for which we will delay the recognition of revenue of approximately $407,000 in 2018. Since we have not yet finalized our assessment, we will continue to monitor and subsequently disclose future identified material impacts, if any, in our annual report on Form 10-K for the year ended December 31, 2017. In addition, the AICPA Power and Utilities Industry Task Force is addressing issues specific to our industry, including CIAC, and has concluded that CIAC is outside of the scope of this standard; accordingly, our Regulated Energy segment accounting for CIAC will not change as a result of ASC 606.

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.

We have assessed all of our leases and have concluded that a majority of our operating leases would continue to fall within the category of operating leases; however, we may have some leases that qualify for the short-term lease exception. We will record the right to use of assets and the lease liability related to the operating leases, but we do not believe that this will have a material impact on our financial position, results of operations and cash flows. During the fourth quarter of 2017, we intend to quantify the overall impact that may result from early adoption of the standard and implementation of the overall process. This guidance will be applied using the modified retrospective transition method for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

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 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 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.

2. Calculation of Earnings Per Share

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$ 6,833**	$ 4,416	**$ 32,023**	$ 32,812
Weighted average shares outstanding	**16,344,442**	15,372,413	**16,334,210**	15,324,932
Basic Earnings Per Share	**$ 0.42**	$ 0.29	**$ 1.96**	$ 2.14
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$ 6,833**	$ 4,416	**$ 32,023**	$ 32,812
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	**16,344,442**	15,372,413	**16,334,210**	15,324,932
Effect of dilutive securities—Share-based compensation	**45,193**	40,370	**44,423**	41,023
Adjusted denominator—Diluted	**16,389,635**	15,412,783	**16,378,633**	15,365,955
Diluted Earnings Per Share	**$ 0.42**	$ 0.29	**$ 1.96**	$ 2.14

3. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC. Chesapeake Utilities' Florida natural gas distribution division and FPU's natural gas and electric distribution operations continue to be subject to regulation, as separate entities, by the Florida PSC.

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 $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.

Maryland

There were no material rates and other regulatory activities for our Maryland division during the period.

Sandpiper

There were no material rates and other regulatory activities for Sandpiper during the period.

Florida

Cost Recovery for the Electric Interconnect Project: In September 2015, FPU’s electric division filed to recover the cost of the proposed Florida Power & Light Company interconnect project through FPU's annual Fuel and Purchased Power Cost Recovery Clause filing. The interconnect project 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. We 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 Florida Power & Light Company, which enables FPU to mitigate fuel costs for its electric customers. This petition is scheduled for the Florida PSC's December 2017 Agenda.

Northwest Florida Expansion Project: Peninsula Pipeline and FPU's natural gas 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 8 miles of 8-inch lateral distribution lines that will be operated by Chesapeake Utilities' Florida natural gas division. We have entered into agreements to serve two large customers and are marketing to other customers close to the facilities.

New Smyrna Beach, Florida Project: Peninsula Pipeline is constructing a pipeline in Volusia County, Florida that will interconnect with FGT's pipeline. The project consists of 14 miles of transmission line from the FGT interconnect that will be operated by Peninsula Pipeline and will serve FPU natural gas distribution customers.

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 ("White Oak Mainline Project"). 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, Eastern Shore submitted a request to the FERC to initiate the pre-filing review procedures for Eastern Shore's 2017 expansion project (the “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; approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. In May 2016, the FERC approved Eastern Shore’s request to commence the pre-filing review process. Eastern Shore entered into Precedent Agreements with 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 seeking authorization to construct the expansion facilities. Six of Eastern Shore's existing customers timely intervened to become parties. In February and March 2017, Eastern Shore submitted responses to the FERC staff's data requests.

In October 2017, FERC issued a CP authorizing Eastern Shore to construct and operate the proposed 2017 Expansion Project. The estimated cost of the 2017 Expansion Project is approximately $115.0 million

Eastern Shore is preparing its implementation plan, which will be filed with the FERC, addressing the actions Eastern Shore will undertake to meet the Environmental Conditions set forth in the FERC's order. Eastern Shore anticipates placing certain facilities into service by the end of the year and completing the entire project in 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. The filing includes incremental rates for the White Oak Lateral Project and White Oak Mainline Expansion Project, which benefits a single customer. Eastern Shore also proposed to revise its depreciation rates and negative salvage rate based on the results of independent, third-party depreciation and negative salvage value studies. 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 $1.0 million for the three and nine months ended September 30, 2017, and established a regulatory liability to reserve a portion of the total incremental revenues generated by the new rates until the rate case is resolved. Settlement discussions continue among the other parties to the case.

4. 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 September 30, 2017, we had approximately $9.7 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 $10.9 million has been recovered as of September 30, 2017, leaving approximately $3.1 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 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

5. 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 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.

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 2.8 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 2.8 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC, and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified in the other agreement.

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

FPU’s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU’s agreement with JEA requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times and (b) a fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU’s electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior 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 September 30, 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 an industrial customer that owns the property on which the CHP plant is located pursuant to a separate 20-year contract. The CHP plant is powered by natural gas transported by FPU through its distribution system and Peninsula Pipeline through its intrastate pipeline.

Corporate Guarantees

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 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 September 30, 2017 was approximately $71.9 million, with the guarantees expiring on various dates through September 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 13, *Long-Term Debt*, for further details).

Letters of Credit

As of September 30, 2017, we have issued letters of credit totaling approximately $5.8 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, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through June 2018. There have been no draws on these letters of credit as of September 30, 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.

Other

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

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. The segments are evaluated based on their pre-tax operating income. Our operations are comprised of two reportable segments:

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

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

Our operations are entirely domestic.

The following table presents financial information about our reportable segments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy segment	**$ 67,257**	$ 68,899	**$ 232,519**	$ 224,382
Unregulated Energy segment and other businesses	**59,679**	39,449	**204,661**	132,604
Total operating revenues, unaffiliated customers	**$ 126,936**	$ 108,348	**$ 437,180**	$ 356,986
Intersegment Revenues [1]				
Regulated Energy segment	**$ 2,446**	$ 1,120	**$ 5,834**	$ 2,248
Unregulated Energy segment	**5,009**	2,593	**15,801**	3,759
Other businesses	**194**	240	**581**	705
Total intersegment revenues	**$ 7,649**	$ 3,953	**$ 22,216**	$ 6,712
Operating Income				
Regulated Energy segment	**$ 15,168**	$ 13,115	**$ 51,915**	$ 52,660
Unregulated Energy segment	**(989)**	(3,080)	**10,504**	9,267
Other businesses and eliminations	**60**	121	**161**	350
Total operating income	**14,239**	10,156	**62,580**	62,277
Other income (expense), net	**239**	(28)	**(643)**	(68)
Interest charges	**3,321**	2,722	**9,133**	7,996
Income before Income Taxes	**11,157**	7,406	**52,804**	54,213
Income taxes	**4,324**	2,990	**20,781**	21,401
Net Income	**$ 6,833**	$ 4,416	**$ 32,023**	**$ 32,812**

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

(in thousands)	September 30, 2017	December 31, 2016
Identifiable Assets		
Regulated Energy segment	**$ 1,084,961**	$ 986,752
Unregulated Energy segment	**233,785**	226,368
Other businesses and eliminations	**28,004**	16,099
Total identifiable assets	**$ 1,346,750**	$ 1,229,219

7. Stockholder's Equity

Preferred Stock

We had 2,000,000 authorized and unissued shares of preferred stock, $0.01 par value per share, as of September 30, 2017 and December 31, 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.

Stockholders' Rights

Pursuant to authority granted under Delaware law and our Certificate of Incorporation, our Board of Directors previously declared a dividend of one preferred stock purchase right (each, a "Right," and, collectively, the "Rights") for each outstanding share of our common stock held of record on September 3, 1999, as adjusted for our stock split in September of 2014, and for additional shares of common stock issued since that time. The description and terms of the Rights are set forth in the Rights Plan. Unless exercised, the Rights trade with our common stock and are evidenced by the common stock certificate. In general, each Right will become exercisable and trade independently from our common stock upon a person or entity acquiring a beneficial ownership of 15 percent or more of our outstanding common stock.

Each Right, if it becomes exercisable, initially entitles the holder to purchase one fiftieth of a share of our Series A Participating Cumulative Preferred Stock, par value $0.01 per share, at a price of $70 per unit, subject to anti-dilution adjustments. Upon a person or entity becoming an "acquiring person," each Right (other than the Rights held by the acquiring person) will become exercisable to purchase a number of shares of our common stock having a market value equal to two times the exercise price of the Right. The Rights expire on August 20, 2019, unless they are redeemed earlier by us at the redemption price of $0.01 per Right. We may redeem the Rights at any time before they become exercisable and thereafter only in limited circumstances.

Accumulated Other Comprehensive Loss

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options and natural gas futures contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated other comprehensive loss.

The following tables present the changes in the balance of accumulated other comprehensive loss for the nine months ended September 30, 2017 and 2016. All amounts 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/(loss) before reclassifications	(9)	322	313
Amounts reclassified from accumulated other comprehensive income/(loss)	271	(965)	(694)
Net current-period other comprehensive income/(loss)	262	(643)	(381)
As of September 30, 2017	$ (5,098)	$ (161)	$ (5,259)

(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 before reclassifications	—	641	641
Amounts reclassified from accumulated other comprehensive income/(loss)	263	(93)	170
Net prior-period other comprehensive income	263	548	811
As of September 30, 2016	$ (5,317)	$ 288	$ (5,029)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and nine months ended September 30, 2017 and 2016. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
(in thousands)				
Amortization of defined benefit pension and postretirement plan items:				
Prior service credit [(1)]	**$ 19**	$ 20	**$ 58**	$ 60
Net loss[(1)]	**(171)**	(166)	**(509)**	(500)
Total before income taxes	**(152)**	(146)	**(451)**	(440)
Income tax benefit	**61**	58	**180**	177
Net of tax	**$ (91)**	$ (88)	**$ (271)**	$ (263)
Gains and losses on commodity contracts cash flow hedges				
Propane swap agreements [(2)]	**$ 198**	$ —	**$ 663**	$ (322)
Natural gas swaps [(2)]	**1**	—	**1**	—
Natural gas futures [(2)]	**(852)**	105	**929**	464
Total before income taxes	**(653)**	105	**1,593**	142
Income tax benefit (expense)	**248**	(41)	**(628)**	(49)
Net of tax	**(405)**	64	**965**	93
Total reclassifications for the period	**$ (496)**	$ (24)	**$ 694**	$ (170)

[(1)] These amounts are included in the computation of net periodic costs (benefits). See Note 8, *Employee Benefit Plans*, for additional details.
[(2)] These amounts are included in the effects of gains and losses from derivative instruments. See Note 11, *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 and call options are included in cost of sales, in the accompanying condensed consolidated statements of income. The income tax benefit is included in income tax income (expense) in the accompanying condensed consolidated statements of income.

8. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three and nine months ended September 30, 2017 and 2016 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 September 30,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
(in thousands)										
Interest cost	**$ 103**	$ 105	**$ 623**	$ 635	**$ 22**	$ 23	**$ 11**	$ 11	**$ 13**	$ 14
Expected return on plan assets	**(127)**	(131)	**(699)**	(625)	**—**	—	**—**	—	**—**	—
Amortization of prior service credit	**—**	—	**—**	—	**—**	—	**(19)**	(20)	**—**	—
Amortization of net loss	**107**	103	**131**	133	**22**	22	**17**	16	**—**	—
Net periodic cost (benefit)	**83**	77	**55**	143	**44**	45	**9**	7	**13**	14
Amortization of pre-merger regulatory asset	**—**	—	**191**	191	**—**	—	**—**	—	**2**	2
Total periodic cost	**$ 83**	$ 77	**$ 246**	$ 334	**$ 44**	$ 45	**$ 9**	$ 7	**$ 15**	$ 16

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Nine Months Ended September 30,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
(in thousands)										
Interest cost	**$ 309**	$ 315	**$ 1,870**	$ 1,894	**$ 66**	$ 68	**$ 31**	$ 32	**$ 38**	$ 41
Expected return on plan assets	**(381)**	(392)	**(2,098)**	(2,027)	**—**	—	**—**	—	**—**	—
Amortization of prior service credit	**—**	—	**—**	—	**—**	—	**(58)**	(60)	**—**	—
Amortization of net loss	**319**	309	**392**	389	**65**	66	**50**	51	**—**	—
Net periodic cost (benefit)	**247**	232	**164**	256	**131**	134	**23**	23	**38**	41
Amortization of pre-merger regulatory asset	**—**	—	**571**	571	**—**	—	**—**	—	**6**	6
Total periodic cost	**$ 247**	$ 232	**$ 735**	$ 827	**$ 131**	$ 134	**$ 23**	$ 23	**$ 44**	$ 47

We expect to record pension and postretirement benefit costs of approximately $1.6 million for 2017. Included in these costs is approximately $769,000 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 $1.5 million and approximately $2.1 million at September 30, 2017 and December 31, 2016, respectively.

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 and nine months ended September 30, 2017 and 2016:

For the Three Months Ended September 30, 2017 *(in thousands)*	**Chesapeake Pension Plan**	**FPU Pension Plan**	**Chesapeake SERP**	**Chesapeake Postretirement Plan**	**FPU Medical Plan**	**Total**
Prior service credit	$ —	$ —	$ —	$ (19)	$ —	$ (19)
Net loss	107	131	22	17	—	277
Total recognized in net periodic benefit cost	107	131	22	(2)	—	258
Recognized from accumulated other comprehensive loss [(1)]	107	25	22	(2)	—	152
Recognized from regulatory asset	—	106	—	—	—	106
Total	$ 107	$ 131	$ 22	$ (2)	$ —	$ 258

For the Three Months Ended September 30, 2016 *(in thousands)*	**Chesapeake Pension Plan**	**FPU Pension Plan**	**Chesapeake SERP**	**Chesapeake Postretirement Plan**	**FPU Medical Plan**	**Total**
Prior service credit	$ —	$ —	$ —	$ (20)	$ —	$ (20)
Net loss	103	133	22	16	—	274
Total recognized in net periodic benefit cost	103	133	22	(4)	—	254
Recognized from accumulated other comprehensive loss [(1)]	103	25	22	(4)	—	146
Recognized from regulatory asset	—	108	—	—	—	108
Total	$ 103	$ 133	$ 22	$ (4)	$ —	$ 254

For the Nine Months Ended September 30, 2017 *(in thousands)*	**Chesapeake Pension Plan**	**FPU Pension Plan**	**Chesapeake SERP**	**Chesapeake Postretirement Plan**	**FPU Medical Plan**	**Total**
Prior service credit	$ —	$ —	$ —	$ (58)	$ —	$ (58)
Net loss	319	392	65	50	—	826
Total recognized in net periodic benefit cost	319	392	65	(8)	—	768
Recognized from accumulated other comprehensive loss [(1)]	319	75	65	(8)	—	451
Recognized from regulatory asset	—	317	—	—	—	317
Total	$ 319	$ 392	$ 65	$ (8)	$ —	$ 768

For the Nine Months Ended September 30, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (60)	$ —	$ (60)
Net loss	309	389	66	51	—	815
Total recognized in net periodic benefit cost	309	389	66	(9)	—	755
Recognized from accumulated other comprehensive loss [1]	309	74	66	(9)	—	440
Recognized from regulatory asset	—	315	—	—	—	315
Total	$ 309	$ 389	$ 66	$ (9)	$ —	$ 755

[1] See Note 7, *Stockholder's Equity*.

During the three and nine months ended September 30, 2017, we contributed approximately $67,000 and $234,000, respectively, to the Chesapeake Pension Plan and approximately $110,000 and $1.6 million, respectively, to the FPU Pension Plan. We expect to contribute a total of approximately $746,000 and approximately $3.0 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2017, 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 and nine months ended September 30, 2017, were approximately $38,000 and $114,000, respectively. We expect to pay total cash benefits of approximately $151,000 under the Chesapeake SERP in 2017. Cash benefits paid under the Chesapeake Postretirement Plan, primarily for medical claims for the three and nine months ended September 30, 2017, were approximately $30,000 and $94,000, respectively. We estimate that approximately $83,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2017. Cash benefits paid under the FPU Medical Plan, primarily for medical claims for the three and nine months ended September 30, 2017, were approximately $13,000 and $48,000, respectively. We estimate that approximately $129,000 will be paid for such benefits under the FPU Medical Plan in 2017.

9. Investments

The investment balances at September 30, 2017 and December 31, 2016, consisted of the following:

(in thousands)	September 30, 2017	December 31, 2016
Rabbi trust (associated with the Deferred Compensation Plan)	**$ 6,358**	$ 4,881
Investments in equity securities	**22**	21
Total	**$ 6,380**	4,902

We classify these investments as trading securities and report them at their fair value. For the three months ended September 30, 2017 and 2016, we recorded a net unrealized gain of approximately $261,000 and $193,000, respectively, in other income (expense), net in the condensed consolidated statements of income related to these investments. For the nine months ended September 30, 2017 and 2016, we recorded an unrealized gain of approximately $694,000 and $246,000, respectively, in other income (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 month for the gains and losses incurred by the investments in the Rabbi Trust.

10. 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 and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
(in thousands)				
Awards to non-employee directors	**$ 134**	$ 135	**$ 406**	$ 445
Awards to key employees	**662**	488	**1,202**	1,442
Total compensation expense	**796**	623	**1,608**	1,887
Less: tax benefit	**(320)**	(251)	**(647)**	(760)
Share-based compensation amounts included in net income	**$ 476**	$ 372	**$ 961**	$ 1,127

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 grant date. 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 service as a director through the 2018 Annual Meeting of Stockholders.

A summary of the stock activity for our non-employee directors during the nine months ended September 30, 2017 is presented below:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2016	—	$ —
Granted	7,515	$ 71.80
Vested	(7,515)	$ 71.80
Outstanding— September 30, 2017	—	$ —

At September 30, 2017, there was approximately $314,000 of unrecognized compensation expense related to these awards. This expense will be recognized over the directors' remaining service periods ending April 30, 2018.

Key Employees

The table below presents the summary of the stock activity for awards to key employees for the nine months ended September 30, 2017:

	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— September 30, 2017	132,642	$ 52.42

In February and May 2017, our Board of Directors granted awards of 52,355 shares of common stock to key employees under the SICP. The shares granted in February and May 2017 are multi-year awards that will vest at the end of the three-year service period ending December 31, 2019. All of these stock awards are earned 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 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.

At the election of certain of our executives, in March 2017, for shares that were awarded for the performance period ending December 31, 2016, we withheld shares with a value at least equivalent to each such executive’s minimum statutory obligation for applicable income and other employment taxes, remitted the cash to the appropriate taxing authorities, and paid the balance of such shares to each such executive. We withheld 10,269 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 September 30, 2017, the aggregate intrinsic value of the SICP awards granted to key employees was approximately $10.4 million. At September 30, 2017, there was approximately $2.7 million of unrecognized compensation cost related to these awards, which is expected to be recognized from 2017 through 2019.

Stock Options

We did not have any stock options outstanding at September 30, 2017 or 2016, nor were any stock options issued during these periods.

11. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to our customers. Aspire Energy has entered into contracts with producers to secure natural gas to meet its obligations. Purchases under these contracts typically either do not meet the definition of derivatives or are considered “normal purchases and normal 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 September 30, 2017, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2017

In 2017, Sharp entered into several swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 11.1 million gallons expected to be purchased from October 2017 through September 2018. Under the swap agreements, Sharp will receive the difference between the index prices (Mont Belvieu prices in October 2017 through September 2018) and the swap prices of $0.5900 and $0.6750 per gallon, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap price, Sharp will pay the difference. We accounted for these swap agreements as cash flow hedges, and there is no ineffective portion of these hedges. At September 30, 2017, the swap agreements had a fair value asset of approximately $1.5 million. 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 other specific customers. These contracts have a two-year term, and we accounted for them as cash flow hedges. There is no ineffective portion of these hedges. At September 30, 2017, PESCO had a total of 4.0 million Dts hedged under natural gas futures contracts, with a liability fair value of approximately $1.3 million accounted for as a cash flow hedge. 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 ARM's financial contracts to mitigate the risk of fluctuations in wholesale natural gas prices associated with 12.0 million Dts PESCO expects to purchase through January 2020. We accounted for these swap agreements as cash flow hedges, with a liability fair value of approximately $412,000. 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 condensed consolidated financial statements for the nine months ended September 30, 2017 was $13,000, which was recorded as an increase in gas costs and is associated with 1.4 million Dts of natural gas. This presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments.

Hedging Activities in 2016

In 2016, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 4.8 million gallons expected to be purchased through September 2017. 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. If the index prices were lower than the swap price, Sharp would pay the difference. Sharp received a total of approximately $193,000, which represented the difference between the index prices and swap prices during the months of October 2016 through September 2017. We had 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 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 had previously accounted for these contracts as fair value hedges, with any ineffective portion being reported directly in earnings and offset by any associated gain (loss) on the inventory value being hedged. During the third quarter of 2016, we discontinued hedge accounting as the hedges were no longer highly effective. As of September 30, 2017, these contracts have all expired and are no longer reported on the balance sheet.

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 September 30, 2017, Xeron had no outstanding contracts that were accounted for as derivatives.

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 September 30, 2017 and December 31, 2016, are as follows:

		Fair Value As Of	
(in thousands)	**Balance Sheet Location**	**September 30, 2017**	**December 31, 2016**
Derivatives not designated as hedging instruments			
Propane swap agreements	Derivative assets, at fair value	**$ 15**	$ 8
Put options	Derivative assets, at fair value	**—**	9
Natural gas swap contracts	Derivative assets, at fair value	**1**	—
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Derivative assets, at fair value	**—**	113
Propane swap agreements	Derivative assets, at fair value	**1,510**	693
Total asset derivatives		**$ 1,526**	$ 823

(in thousands)	Liability Derivatives Balance Sheet Location	Fair Value As Of September 30, 2017	December 31, 2016
Derivatives not designated as hedging instruments			
Natural gas futures contracts	Derivative liabilities, at fair value	**$ 13**	**$773**
Derivatives designated as cash flow hedges			
Natural gas swap contracts	Derivative liabilities, at fair value	**412**	—
Natural gas futures contracts	Derivative liabilities, at fair value	**1,307**	—
Total liability derivatives		**$ 1,732**	$ 773

The effects of gains and losses from derivative instruments on the condensed consolidated financial statements are as follows:

(in thousands)	Location of Gain (Loss) on Derivatives	Amount of Gain (Loss) on Derivatives: For the Three Months Ended September 30, 2017	2016	For the Nine Months Ended September 30, 2017	2016
Derivatives not designated as hedging instruments					
Realized gain on forward contracts and options (1)	Revenue	**$ —**	$ (231)	**$ 112**	$ 44
Unrealized gain (loss) on forward contracts (1)	Revenue	**—**	(2)	**—**	—
Natural gas futures contracts	Cost of sales	**286**	205	**907**	205
Propane swap agreements	Cost of sales	**15**	—	**11**	—
Natural gas swap contracts	Cost of sales	**1**	—	**1**	—
Derivatives designated as fair value hedges					
Put /Call option (2)	Cost of sales	**—**	—	**(9)**	73
Natural gas futures contracts	Natural gas inventory	**—**	—	**—**	(233)
Derivatives designated as cash flow hedges					
Propane swap agreements	Cost of sales	**198**	—	**663**	(364)
Propane swap agreements	Other comprehensive income	**1,590**	213	**814**	559
Natural gas futures contracts	Cost of sales	**(852)**	105	**929**	464
Natural gas futures contracts	Other comprehensive income (loss)	**(1,296)**	(123)	**(1,420)**	349
Natural gas swap agreements	Cost of sales	**1**	—	**1**	—
Natural gas swap agreements	Other comprehensive loss	**(413)**	—	**(413)**	—
Total		**$ (470)**	$ 167	**$ 1,596**	$ 1,097

(1) All of the realized and unrealized gain (loss) on forward contracts represents the effect of trading activities on our condensed 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 put option effectively changed the value of propane inventory on the condensed consolidated balance sheets.

12. Fair Value of Financial Instruments

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are the following:

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

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability; and

Level 3: Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity).

Financial Assets and Liabilities Measured at Fair Value

The following table summarizes 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 September 30, 2017 and December 31, 2016:

		Fair Value Measurements Using:		
As of September 30, 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	**642**	**—**	**—**	**642**
Investments—mutual funds and other	**5,716**	**5,716**	**—**	**—**
Total investments	**6,380**	**5,738**	**—**	**642**
Derivative assets	**1,526**	**—**	**1,526**	**—**
Total assets	**$ 7,906**	**$ 5,738**	**$ 1,526**	**$ 642**
Liabilities:				
Derivative liabilities	**$ 1,732**	**$ —**	**$ 1,732**	**$ —**

		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 the fair value of assets and liabilities in the tables above:

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 nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,	
(in thousands)	**2017**	**2016**
Beginning Balance	**$ 561**	$ 279
Purchases and adjustments	**76**	120
Transfers	**—**	88
Distribution	**(2)**	(8)
Investment income	**7**	6
Ending Balance	**$ 642**	$ 485

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

At September 30, 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 September 30, 2017, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of approximately $211.4 million. This compares to a fair value of approximately $224.2 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, 2016, long-term debt, including the current maturities but excluding a capital lease obligation, had a carrying value of approximately $145.9 million, compared to the estimated fair value of approximately $161.5 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

13. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	September 30, 2017	December 31, 2016
FPU secured first mortgage bonds [1] :		
9.08% bond, due June 1, 2022	**$ 7,981**	$ 7,978
Uncollateralized senior notes:		
6.64% note, due October 31, 2017	**2,727**	2,727
5.50% note, due October 12, 2020	**8,000**	8,000
5.93% note, due October 31, 2023	**19,500**	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	**2,425**	3,471
Less: debt issuance costs	**(446)**	(291)
Total long-term debt	**213,384**	149,053
Less: current maturities	**(12,136)**	(12,099)
Total long-term debt, net of current maturities	**$ 201,248**	$ 136,954

[1] FPU secured first mortgage bonds are guaranteed by Chesapeake Utilities.

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 confirmed and accepted our request that Prudential 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.

The Prudential Shelf Agreement sets forth certain business covenants to which we are subject when any Prudential Shelf 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.

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. As of September 30, 2017, no unsecured senior debt has been issued under the MetLife and NYL Shelf Agreements.

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, 2016, 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 event or otherwise. These statements are subject to many risks and uncertainties. In addition to the risk factors described under Item 1A, Risk Factors in our 2016 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 (including deregulation) that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree of competition entering the electric and natural gas industries;
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recoverable in rates;
- the timing of certificate authorizations associated with new capital projects;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now or may in the future own or operate;
- possible increased federal, state and local regulation of the safety of our operations;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- the timing and extent of changes in commodity prices and interest rates;
- the ability to establish and maintain key supply sources;
- the effect of spot, forward and future market prices on our various energy businesses;
- the effect of competition on our businesses;
- the capital-intensive nature of our regulated energy businesses;
- the extent of our success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the ability to construct facilities at or below estimated costs and within projected time frames;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the impact on our cost and funding obligations under our pension and other post-retirement benefit plans of potential downturns in the financial markets, lower discount rates, and costs associated with the Patient Protection and Affordable Care Act;
- the ability to continue to hire, train and retain appropriately qualified personnel;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- the timing and success of technological improvements;
- risks related to cyber-attacks that could disrupt our business operations or result in failure of information technology systems;
- the impact of significant changes to current tax regulations and rates; and

- the impact of future rate case proceedings.

Introduction

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

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

The key elements of this strategy include:

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

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 elsewhere in this Quarterly Report on Form 10-Q 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 operations and under our competitive pricing structure for non-regulated segments. Our management uses gross margin in measuring its 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.

Results of Operations for the Three and Nine Months ended September 30, 2017

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 regulated energy, unregulated 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.

Operational Highlights

Our net income for the quarter ended September 30, 2017 was $6.8 million, or $0.42 per share. This represents an increase of $2.4 million, or $0.13 per share, compared to net income of $4.4 million, or $0.29 per share, reported for the same quarter in 2016. Operating income increased $4.1 million for the three months ended September 30, 2017.

	Three Months Ended September 30,		Increase
	2017	**2016**	**(decrease)**
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	**$ 15,168**	$ 13,115	$ 2,053
Unregulated Energy segment	**(989)**	(3,080)	2,091
Other businesses and eliminations	**60**	121	(61)
Operating Income	**$ 14,239**	$ 10,156	$ 4,083
Other income (expense), net	239	(28)	267
Interest charges	**3,321**	2,722	599
Pre-tax Income	**11,157**	7,406	3,751
Income taxes	**4,324**	2,990	1,334
Net Income	**$ 6,833**	$ 4,416	$ 2,417
Earnings Per Share of Common Stock			
Basic	**$ 0.42**	$ 0.29	$ 0.13
Diluted	**$ 0.42**	$ 0.29	$ 0.13

Key variances, between the third quarter of 2017 and the third quarter of 2016, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Third Quarter of 2016 Reported Results	**$ 7,406**	**$ 4,416**	**$ 0.29**
Adjusting for unusual items:			
Absence of Xeron's third quarter 2016 loss	545	334	0.02
Weather impact	(333)	(204)	(0.01)
	212	130	0.01
Increased Gross Margins:			
Customer consumption (non-weather)	1,166	714	0.05
Implementation of new rates for Eastern Shore*	1,020	625	0.04
Retail propane margins	440	270	0.02
GRIP*	406	249	0.02
Natural gas growth (excluding service expansions)	347	213	0.01
Eight Flags' CHP plant	304	186	0.01
Pricing amendments to Aspire Energy's long-term agreements	291	178	0.01
Higher wholesale propane volumes and margins	271	166	0.01
	4,245	2,601	0.17
Decreased (Increased) Other Operating Expenses:			
Higher depreciation, asset removal and property tax costs due to new capital investments	(1,710)	(1,047)	(0.07)
Lower outside services and facilities maintenance costs	1,678	1,028	0.07
Higher payroll expense	(913)	(559)	(0.04)
Lower benefit and other employee-related expenses	295	181	0.01
Eight Flags' operating expenses	293	179	0.01
	(357)	(218)	(0.02)
Net other changes	(349)	(96)	(0.01)
	(349)	(96)	(0.01)
EPS impact of increase in outstanding shares due to September 2016 offering	—	—	(0.02)
Third Quarter of 2017 Reported Results	**$ 11,157**	**$ 6,833**	**$ 0.42**

*__See the Major Projects and Initiatives table.__

Our net income for the nine months ended September 30, 2017 was $32.0 million, or $1.96 per share. This represents a decrease of $789,000, or $0.18 per share, compared to net income of $32.8 million, or $2.14 per share, reported for the same period in 2016. Operating income increased $303,000 for the nine months ended September 30, 2017.

	Nine Months Ended September 30,		
	2017	**2016**	**Increase (decrease)**
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	**$ 51,915**	$ 52,660	$ (745)
Unregulated Energy segment	**10,504**	9,267	1,237
Other businesses and eliminations	**161**	350	(189)
Operating Income	**$ 62,580**	$ 62,277	$ 303
Other expense, net	(643)	(68)	(575)
Interest charges	**9,133**	7,996	1,137
Pre-tax Income	**52,804**	54,213	(1,409)
Income taxes	**20,781**	21,401	(620)
Net Income	**$ 32,023**	$ 32,812	$ (789)
Earnings Per Share of Common Stock			
Basic	**$ 1.96**	$ 2.14	$ (0.18)
Diluted	**$ 1.96**	$ 2.14	$ (0.18)

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Key variances, between the nine months ended 2017 and the nine months ended 2016, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Nine Months Ended September 30, 2016 Reported Results	**$ 54,213**	**$ 32,812**	**$ 2.14**
Adjusting for unusual items:			
Weather impact	(1,782)	(1,081)	(0.07)
Wind-down and absence of loss from Xeron operations	(341)	(207)	(0.01)
	(2,123)	(1,288)	(0.08)
Increased Gross Margins:			
Eight Flags' CHP plant	4,721	2,863	0.19
Natural gas marketing	1,760	1,067	0.07
GRIP*	1,619	982	0.06
Natural gas growth (excluding service expansions)	1,574	955	0.06
Service expansions*	1,371	831	0.05
Pricing amendments to Aspire Energy's long-term agreements	1,143	693	0.04
Implementation of new rates for Eastern Shore*	1,020	619	0.04
Wholesale propane margins	728	441	0.03
Customer consumption (non-weather)	700	425	0.03
Implementation of Delaware Division settled rates	249	151	0.01
	14,885	9,027	0.58
Increased Other Operating Expenses:			
Higher depreciation, asset removal and property tax costs due to new capital investments	(4,251)	(2,578)	(0.17)
Higher payroll expense	(3,074)	(1,864)	(0.12)
Eight Flags' operating expenses	(2,821)	(1,711)	(0.11)
Higher benefit and other employee-related expenses	(1,669)	(1,012)	(0.07)
Higher regulatory expenses associated with rate filings	(855)	(519)	(0.03)
Higher outside services and facilities maintenance costs	(318)	(193)	(0.01)
	(12,988)	(7,877)	(0.51)
Interest charges	(1,136)	(689)	(0.04)
Net other changes	(47)	38	(0.01)
	(1,183)	(651)	(0.05)
EPS impact of increase in outstanding shares due to September 2016 offering	—	—	(0.12)
Nine Months Ended September 30, 2017 Reported Results	**$ 52,804**	**$ 32,023**	**$ 1.96**

*__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									
	Three Months Ended September 30,			Nine Months Ended September 30,			Year Ended December 31,	Estimate for		
	2017	2016	Variance	2017	2016	Variance	2016	2017	2018	2019
Major Projects and Initiatives Recently Completed										
Capital Investment Projects	**$ 9,807**	$ 8,963	$ 844	**$ 29,533**	$ 21,822	$ 7,711	$ 29,819	$ 35,346	$ 31,814	$ 32,724
Eastern Shore Rate Case [1]	**1,020**	—	1,020	**1,020**	—	1,020	—	TBD	TBD	TBD
Settled Delaware Division Rate Case	**431**	469	(38)	**1,596**	1,347	249	1,487	2,250	2,250	2,250
Total Major Projects and Initiatives Recently Completed	**11,258**	9,432	1,826	**32,149**	23,169	8,980	31,306	37,596	34,064	34,974
Future Major Projects and Initiatives										
Capital Investment Projects										
2017 Eastern Shore System Expansion	**—**	—	—	**—**	—	—	—	126	9,313	15,799
Northwest Florida Expansion	**—**	—	—	**—**	—	—	—	—	3,484	5,127
Other Florida Pipeline Expansions	**—**	—	—	**—**	—	—	—	—	2,044	2,542
Total Future Major Projects and Initiatives	**—**	—	—	**—**	—	—	—	126	14,841	23,468
Total	**$ 11,258**	$ 9,432	$ 1,826	**$ 32,149**	$ 23,169	$ 8,980	$ 31,306	$ 37,722	$ 48,905	$ 58,442

[1] In January 2017, Eastern Shore filed a rate case with the FERC to recover the costs of the 2016 System Reliability Project and other investments and expenses associated with the expansion, reliability and safety initiatives completed by ESNG since its last rate settlement in 2012. Settlement discussions among Eastern Shore, intervenors and the FERC Staff are ongoing and future margin contributions will be provided once a settlement is finalized. For the third quarter of 2017, a portion of the increase in rates, implemented subject to refund in August 2017, has been recorded as revenue and the remainder has been reserved pending the settlement. See Note 3, *Rates and Other Regulatory Activities*, for additional information.

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									
	Three Months Ended September 30,			Nine Months Ended September 30,			Year Ended December 31,	Estimate for		
	2017	2016	Variance	2017	2016	Variance	2016	2017	2018	2019
Capital Investment Projects:										
Service Expansions:										
Short-term contracts (Delaware)	**$ 1,283**	$ 3,080	$ (1,797)	**$ 5,140**	$ 8,271	$ (3,131)	$ 11,454	$ 5,642	$ 1,096	$ 1,096
Long-term contracts (Delaware)	**2,793**	862	1,931	**7,089**	2,587	4,502	1,815	7,611	7,605	7,583
Total Service Expansions	**4,076**	3,942	134	**12,229**	10,858	1,371	13,269	13,253	8,701	8,679
Florida GRIP	**3,393**	2,987	406	**10,002**	8,383	1,619	11,552	13,727	14,407	15,085
Eight Flags' CHP Plant	**2,338**	2,034	304	**7,302**	2,581	4,721	4,998	8,366	8,706	8,960
Total Capital Investment Projects	**9,807**	8,963	844	**29,533**	21,822	7,711	29,819	35,346	31,814	32,724
Eastern Shore Rate Case [1]	**1,020**	—	1,020	**1,020**	—	1,020	—	TBD	TBD	TBD
Settled Delaware Division Rate Case	**431**	469	(38)	**1,596**	1,347	249	1,487	2,250	2,250	2,250
Total Major Projects and Initiatives Recently Completed	**$ 11,258**	$ 9,432	$ 1,826	**$ 32,149**	$ 23,169	$ 8,980	$ 31,306	$ 37,596	$ 34,064	$ 34,974

[(1)] In January 2017, Eastern Shore filed a rate case with the FERC to recover the costs of the 2016 System Reliability Project and other investments and expenses associated with the expansion, reliability and safety initiatives completed by ESNG since its last rate settlement in 2012. Settlement discussions among Eastern Shore, intervenors and the FERC Staff are ongoing and future margin contributions will be provided once a settlement is finalized. For the third quarter of 2017, a portion of the increase in rates, implemented subject to refund in August 2017, has been recorded as revenue and the remainder has been reserved pending the settlement. See Note 3, *Rates and Other Regulatory Activities*, for additional information.

Service Expansions

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/d deliverable to the lateral serving the customer's facility. 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 pending construction of facilities. Construction of the project was completed, and long-term service commenced in March 2017. This service generated an additional gross margin of $106,000 during the nine months ended September 30, 2017 compared to the same period in 2016. There was no incremental margin change during the third quarter as the margin generated from the permanent services equated to the margin generated from providing interim services during the third quarter of 2016. This service is expected to generate gross margin of $7.0 million for 2017 and between $5.8 million and $7.8 million annually through the remaining term of the agreement.

In December 2015, the FERC approved Eastern Shore's application to make certain meter tube and control valve replacements and related 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. The project was completed and placed in service in March 2016. Approximately 35 percent of the increased capacity has been subscribed on a short-term firm service basis through October 2017. This service generated additional gross margin of $80,000 and $1.3 million for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016. The remaining capacity is available for firm or interruptible service.

GRIP

GRIP is a natural gas pipe replacement program approved by the Florida PSC, designed to expedite the replacement of qualifying distribution mains and services (any material other than coated steel or plastic) to enhance 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 $110.5 million to replace 240 miles of qualifying distribution mains, including $7.6 million during the first nine months of 2017. The increased investment in GRIP generated additional gross margin of $406,000 and $1.6 million for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016.

Eight Flags' CHP plant

In June 2016, Eight Flags completed construction of a CHP plant on Amelia Island, Florida. This CHP plant, which consists of a natural-gas-fired turbine and associated electric generator, produces approximately 20 MWH of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of residual steam. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU, pursuant to a 20-year power purchase agreement for distribution to its retail electric customers. In July 2016, it also started selling steam to the industrial customer that owns the property on which Eight Flags' CHP plant is located, pursuant to a separate 20-year contract.

The CHP plant is powered by natural gas transported by FPU through its distribution system and by Peninsula Pipeline. For the three and nine months ended September 30, 2017, Eight Flags and other affiliates of Chesapeake Utilities generated $304,000 and $4.7 million, in additional gross margin as a result of these services that began in June 2016. This amount includes gross margin of $7,000 and $534,000, for the three and nine months ended September 30, 2017, respectively, attributable to natural gas distribution and transportation services provided to the CHP plant by Chesapeake Utilities' regulated affiliates.

System Reliability Project

In July 2016, the FERC authorized Eastern Shore to construct and operate the System Reliability Project, which consisted of approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware, and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. A 2.5 mile looping segment was completed and placed into service in December 2016. The remaining looping and the new compressor were completed and placed into service in the second quarter of 2017. This project was included in Eastern Shore's January 2017 base rate case filing with the FERC. 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.

Major Projects and Initiatives Currently Underway

Northwest Florida Expansion Project
Peninsula Pipeline and FPU's natural gas 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 8 miles of 8-inch lateral distribution lines that will be operated by Chesapeake Utilities' Florida natural gas division. We entered into agreements to serve two industrial customers and are currently marketing to other potential customers located close to the facilities. The estimated annual gross margin associated with this project, once in service, is approximately $5.1 million.

New Smyrna Beach, Florida Project
Peninsula Pipeline is constructing a pipeline in Volusia County, Florida that will interconnect with FGT's pipeline. The project consists of 14 miles of transmission line from the FGT interconnect that will be operated by Peninsula Pipeline and will serve FPU natural gas distribution customers. The estimated annual gross margin associated with this project, once in service, is approximately $1.4 million.

2017 Expansion Project
In May 2016, Eastern Shore submitted a request to the FERC to initiate the FERC's pre-filing process for its proposed 2017 Expansion Project. This project, which will expand Eastern Shore's firm service capacity by 26 percent, will provide 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 Eastern Shore entered into with existing customers. We expect to invest approximately $115.0 million in this expansion project, and for the project to generate approximately $15.8 million of gross margin in the first full year after the new transportation services go into effect. On October 4, 2017, the FERC issued a CP authorizing Eastern Shore to construct and operate the proposed 2017 expansion project.

Other major factors influencing gross margin

Weather and Consumption

Temperature variation in 2017 negatively impacted our earnings. Compared to the prior year, cooler temperatures in Florida during the third quarter of 2017, reduced gross margin by $333,000, and warmer temperatures in all of our service territories during the first nine months of 2017, reduced gross margin by $1.8 million, respectively. Warmer than normal temperatures for the quarter and nine months ended September 30, 2017 reduced gross margin by $193,000 and $4.3 million, respectively. The following table summarizes HDD and CDD variances from the 10-year average HDD/CDD ("Normal") for the three and nine months ended September 30, 2017 and 2016.

HDD and CDD Information

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	**2016**	**Variance**	**2017**	**2016**	**Variance**
Delmarva						
Actual HDD	**16**	11	5	**2,262**	2,590	(328)
10-Year Average HDD ("Delmarva Normal")	**62**	65	(3)	**2,845**	2,919	(74)
Variance from Delmarva Normal	**(46)**	(54)		**(583)**	(329)	
Florida						
Actual HDD	**—**	—	—	**298**	514	(216)
10-Year Average HDD ("Florida Normal")	**—**	—	—	**602**	553	49
Variance from Florida Normal	**—**	—		**(304)**	(39)	
Ohio						
Actual HDD	**80**	39	41	**3,072**	3,596	(524)
10-Year Average HDD ("Ohio Normal")	**92**	103	(11)	**3,866**	3,865	1
Variance from Ohio Normal	**(12)**	(64)		**(794)**	(269)	
Florida						
Actual CDD	**1,526**	1,679	(153)	**2,606**	2,792	(186)
10-Year Average CDD ("Florida CDD Normal")	**1,542**	1,523	19	**2,579**	2,548	31
Variance from Florida CDD Normal	**(16)**	156		**27**	244	

Propane Operations

Our Florida and Delmarva propane distribution operations added $2.0 million and $1.4 million, in incremental margin for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016. Higher volumes sold to retail customers and improved margins due to effective supply management activities generated $905,000 and $440,000, in incremental margin, for the three months ended September 30, 2017, respectively, compared to the same period in 2016 and higher service revenue added $187,000 in additional margin, during the quarter.

For the nine months ended September 2017, higher volumes sold to retail customers and improved margins due to effective supply management activities generated $142,000 and $121,000, in incremental margin, respectively, compared to the same period in 2016 and higher service revenue added $244,000, in additional margin during the period.

Wholesale propane margins increased, generating additional gross margin of $271,000 and $728,000 for the three and nine months ended September 30, 2017, respectively, due primarily to higher volumes sold and improved margins resulting from supply management activities.

PESCO

PESCO provides natural gas supply and supply management services to residential, commercial, industrial and wholesale customers. PESCO operates primarily in Florida, on the Delmarva Peninsula, in Ohio, and, as a result of the recent acquisition of certain operating assets of ARM, in western Pennsylvania. PESCO competes with regulated utilities and other unregulated third-party marketers to sell natural gas supplies directly to residential, commercial and industrial customers through competitively-priced contracts. PESCO does not currently own or operate any natural gas transmission or distribution assets but sells gas that is delivered to retail, commercial or wholesale customers through affiliated and non-affiliated local distribution company systems and transmission pipelines.

In 2017, our Delmarva natural gas distribution operations entered into asset management agreements with PESCO to manage a portion of their natural gas transportation and storage capacity. The asset management agreements were effective April 1, 2017, and each has a three-year term, expiring on March 31, 2020. As a result of these agreements, PESCO manages capacity on regional pipelines as well as third-party storage contracts for our Delmarva natural gas distribution operations in conjunction with PESCO's asset management services.

For the three months ended September 30, 2017, PESCO's gross margin increased by $56,000. For the nine months ended September 30, 2017, PESCO generated additional gross margin of $1.8 million compared to the same period in 2016, as a result of revenues from a supplier agreement with a customer in Ohio, which expired on March 31, 2017, as well as additional customers in Florida, partially offset by lower margin in the Mid-Atlantic region, primarily during the first quarter of 2017.

Xeron

As disclosed previously, Xeron's operations were wound down during the second quarter of 2017. As a result, Xeron did not generate an operating loss during the third quarter of 2017 and will not report operating results during the fourth quarter of 2017 or subsequent years. During the third quarter of 2016, Xeron generated a pre-tax loss of $486,000. On a year-to-date basis, Xeron's pre-tax operating loss increased by $375,000, compared to the same period in 2016, driven primarily by non-recurring employee severance costs and costs associated with the termination of leased office space in Houston, Texas. The Company does not anticipate incurring any additional costs that will have a material impact associated with winding down Xeron's operations.

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $379,000 and $1.0 million in additional gross margin for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016, due to an increase in residential, commercial and industrial customers served. The average number of residential customers on the Delmarva Peninsula increased by 3.7 percent and 3.8 percent during the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016. The natural gas distribution operations in Florida generated $187,000 and $1.2 million in additional gross margin for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016, due primarily to an increase in commercial and industrial customers in Florida.

Regulatory Proceedings

Delaware Division Rate Case

In December 2016, the Delaware PSC approved a settlement agreement, which, among other things, provided for an increase in our Delaware division revenue requirement of $2.25 million and a rate of return on common equity of 9.75 percent. The new authorized rates went into effect on January 1, 2017. For the three months ended September 30, 2017, compared to the same period in 2016, revenue decreased by $38,000, reflecting the variance between settled and interim rates. For the nine months ended September 30, 2017 compared to the same period in 2016, we recorded incremental revenue of approximately $249,000 related to the rate case. Any amounts collected through 2016 interim rates in excess of the respective portion of the $2.25 million were refunded to the ratepayers in March 2017.

Eastern Shore Rate Case

In January 2017, Eastern Shore filed a base rate proceeding with the FERC, as required by the terms of its 2012 rate case settlement agreement. Eastern Shore's proposed rates 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. The filing includes incremental rates for the White Oak Lateral Project and White Oak Mainline Expansion Project, which benefits a single customer. Eastern Shore also proposed to revise its depreciation rates and negative salvage rate based on the results of independent, third-party depreciation and negative salvage value studies. 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 $1.0 million for the three and nine months ended September 30, 2017, and established a regulatory liability to reserve a portion of the total incremental revenues generated by the new rates until resolution of the rate case. Settlement discussions continue with other parties to the case.

Investing for Future Growth

To support and continue our growth, we have expanded, and will continue to expand, our resources and capabilities. Eastern Shore previously expanded, and continues to significantly expand, its transmission system, which require additional staffing. We requested recovery of most of Eastern Shore's increased staffing costs in its 2017 rate case. Growth in non-regulated energy businesses, including Aspire Energy, PESCO and Eight Flags, also 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 assist in developing additional initiatives, staffing and resources have been added in our corporate shared services departments. For the three and nine months ended September 30, 2017, our staffing and associated costs increased by $617,000 and $4.7 million, respectively, or three percent and nine percent, respectively, compared to the same periods in 2016. 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 capitalize on future growth opportunities.

Regulated Energy Segment

For the quarter ended September 30, 2017 compared to the quarter ended September 30, 2016

	Three Months Ended September 30,		Increase
	2017	**2016**	**(decrease)**
(in thousands)			
Revenue	**$ 69,703**	$ 70,019	$ (316)
Cost of sales	**22,794**	24,644	(1,850)
Gross margin	**46,909**	45,375	1,534
Operations & maintenance	**21,149**	22,912	(1,763)
Depreciation & amortization	**7,338**	6,346	992
Other taxes	**3,254**	3,002	252
Other operating expenses	**31,741**	32,260	(519)
Operating income	**$ 15,168**	$ 13,115	$ 2,053

Operating income for the Regulated Energy segment for the three months ended September 30, 2017 was $15.2 million, an increase of $2.1 million compared to the same period in 2016. The increased operating income resulted from increased gross margin of $1.5 million and a decrease in operating expenses of $519,000.

Gross Margin

Items contributing to the quarter-over-quarter increase of $1.5 million, or 3.4 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2016	$ 45,375
Factors contributing to the gross margin increase for the three months ended September 30, 2017:	
Implementation of Eastern Shore rates	1,020
Additional Revenue from GRIP in Florida	406
Natural gas growth (excluding service expansions)	347
Other	(239)
Gross margin for the three months ended September 30, 2017	$ 46,909

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 $1.0 million from the implementation of new rates as a result of its rate case filing. See *Note 3, Rates and Other Regulatory Activities*, to the condensed consolidated financial statements for additional details.

Additional Revenue from GRIP in Florida

Increased investment in GRIP generated additional gross margin of $406,000 for the three months ended September 30, 2017, compared to the same period in 2016.

Natural Gas Growth (excluding service expansions)

Increased gross margin of $347,000 from other growth in natural gas (excluding service expansions) was generated primarily from the following:

- $379,000 from a four-percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers;
- $187,000 from Florida natural gas customer growth, due primarily to new services to commercial and industrial customers; and
- which were partially offset by $219,000 in decreased margin from Eastern Shore's interruptible services.

Other Operating Expenses

Other operating expenses decreased by $519,000. The significant factors contributing to the decrease in other operating expenses included:

- $1.6 million in lower costs related to outside services and facilities and maintenance costs, due primarily to lower consulting and service contractor costs;
- $437,000 in lower benefits and employee-related costs (since we are self-insured for healthcare, benefits costs fluctuate depending upon filed claims);
- $1.4 million in higher depreciation, asset removal and property tax costs associated with recent capital investments.

For the Nine Months Ended September 30, 2017 compared to the nine months ended September 30, 2016

	Nine Months Ended September 30,		Increase
(in thousands)	**2017**	**2016**	**(decrease)**
Revenue	**$ 238,353**	$ 226,630	$ 11,723
Cost of sales	**87,206**	81,184	6,022
Gross margin	**151,147**	145,446	5,701
Operations & maintenance	**67,869**	64,673	3,196
Depreciation & amortization	**21,365**	18,909	2,456
Other taxes	**9,998**	9,204	794
Other operating expenses	**99,232**	92,786	6,446
Operating income	**$ 51,915**	$ 52,660	$ (745)

Operating income for the Regulated Energy segment for the nine months ended September 30, 2017 was $51.9 million, a decrease of $745,000 compared to the same period in 2016. The decreased operating income was due to an increase in gross margin of $5.7 million, offset by higher operating expenses of $6.4 million. Of the total $6.4 million increase in operating expenses, $4.7 million is associated with Eastern Shore's recently completed projects as well as initiatives underway.

Gross Margin

Items contributing to the period-over-period increase of $5.7 million, or 3.9 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2016	$ 145,446
Factors contributing to the gross margin increase for the nine months ended September 30, 2017:	
Additional revenue from GRIP in Florida	1,619
Natural gas growth (excluding service expansions)	1,574
Service expansions	1,371
Customer consumption - weather and other	(1,249)
Implementation of Eastern Shore rates	1,020
Service to Eight Flags	534
Implementation of Delaware Division Rates	249
Other	583
Gross margin for the nine months ended September 30, 2017	$ 151,147

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.

Additional Revenue from GRIP in Florida

Increased investment in GRIP generated additional gross margin of $1.6 million for the nine months ended September 30, 2017, compared to the same period in 2016.

Natural Gas Growth (Excluding Service Expansions)

Increased gross margin of $1.6 million from growth (excluding service expansions) was generated primarily from the following:

- $1.2 million from Florida natural gas customer growth, due primarily to new services to commercial and industrial customers; and
- $1.0 million from a four-percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers.

Service Expansions

Eastern Shore generated increased gross margin of $1.4 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, Eastern Shore's natural gas receipt capacity from TETLP increased by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. The remaining capacity is available for firm or interruptible service.

Customer Consumption - Weather and Other

Gross margin decreased by $1.2 million from lower customer consumption of electricity and natural gas, due primarily to warmer temperatures in Florida and on the Delmarva Peninsula. Because Maryland and Sandpiper Energy rates include a weather normalization adjustment for residential heating and smaller commercial heating customers, these operations experienced minimal impact from the warmer weather during the first nine months of 2017.

Implementation of Eastern Shore Rates

Eastern Shore generated additional gross margin of $1.0 million from implementation of new rates as a result of its rate case filing. See *Note 3, Rates and Other Regulatory Activities,* to the condensed consolidated financial statements for additional details.

Service to Eight Flags

We generated additional gross margin of $534,000 in the nine months ended September 30, 2017, compared to the same period in 2016, from new natural gas transmission and distribution services provided by our affiliates to Eight Flags' CHP plant.

Implementation of Delaware Division Rates

Our Delaware Division generated additional gross margin of $249,000 as a result of the settlement of the rate case. See *Note 3, Rates and Other Regulatory Activities*, to the condensed consolidated financial statements for additional details.

Other Operating Expenses

Other operating expenses increased by $6.4 million. The significant components of the increase in other operating expenses included:

- $3.5 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $1.6 million in higher payroll expenses for addition personnel to support growth;
- $855,000 in increased regulatory expenses, due primarily to costs associated with Eastern Shore’s rate case filing in 2017; and
- $722,000 in higher benefits and employee-related costs in 2017 (since we are self-insured for healthcare, benefits costs fluctuate depending upon claims filed).

Unregulated Energy Segment

For the quarter ended September 30, 2017 compared to the quarter ended September 30, 2016

	Three Months Ended September 30,		Increase
	2017	**2016**	**(decrease)**
(in thousands)			
Revenue	**$ 64,688**	$ 42,042	$ 22,646
Cost of sales	**51,416**	31,840	19,576
Gross margin	**13,272**	10,202	3,070
Operations & maintenance	**11,460**	10,975	485
Depreciation & amortization	**2,001**	1,840	161
Other taxes	**800**	467	333
Total operating expenses	**14,261**	13,282	979
Operating loss	**$ (989)**	$ (3,080)	$ 2,091

Operating loss for the Unregulated Energy segment for the three months ended September 30, 2017 was $989,000, compared to the operating loss of $3.1 million for same period in 2016. The decreased operating loss was due to an increase in gross margin of $3.1 million, which was offset by a $1.0 million increase in operating expenses.

Gross Margin

Items contributing to the quarter-over-quarter increase of $3.1 million in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2016	$ 10,202
Factors contributing to the gross margin increase for the three months ended September 30, 2017:	
Customer Consumption - Weather and Other	1,165
Retail Propane Margins	440
Eight Flags' CHP Plant	297
Pricing Amendments to Aspire Energy's Long-Term Agreements	291
Wholesale Propane Margins	271
Wind-down of Xeron operations	233
Other	373
Gross margin for the three months ended September 30, 2017	$ 13,272

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.

Customer Consumption - Weather and Other

Gross margin increased by $1.2 million, due primarily to increased sales volumes of propane to wholesale and retail customers on the Delmarva Peninsula and higher retail propane sales volumes in Florida due primarily to the timing of deliveries.

Retail Propane Margins

Gross margin increased by $440,000, due primarily to favorable supply management activities.

Eight Flags

Eight Flags' CHP plant, which commenced operations in June 2016, generated $297,000 in additional gross margin due primarily to Eight Flags being fully on-line in the third quarter of 2017.

Pricing Amendments to Aspire Energy Long-Term Agreements

An increase in gross margin of $291,000 was due to pricing amendments to long-term sales agreements.

Wholesale Propane Margins

Gross margin increased by $271,000, due primarily to favorable supply management activities for the Delmarva propane distribution operations.

Xeron

The absence of the prior year operating loss increased gross margin by $233,000.

Other Operating Expenses

Other operating expenses increased by $1.0 million. The significant components of the increase in other operating expenses included:

- $730,000 in higher staffing and associated costs for additional personnel to support growth (since we are self-insured for healthcare, benefits costs fluctuate depending upon claims filed);
- $347,000 in higher depreciation, amortization and property tax costs due to increased capital investments and amortization of intangible assets acquired through acquisitions in 2017; and
- $293,000 in expenses associated with the incremental margin from Eight Flags

For the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016

	Nine Months Ended September 30,		
(in thousands)	**2017**	**2016**	**Increase (decrease)**
Revenue	**$ 220,462**	$ 136,361	$ 84,101
Cost of sales	**166,635**	90,981	75,654
Gross margin	**53,827**	45,380	8,447
Operations & maintenance	**34,971**	30,136	4,835
Depreciation & amortization	**5,833**	4,512	1,321
Other taxes	**2,519**	1,465	1,054
Total operating expenses	**43,323**	36,113	7,210
Operating income	**$ 10,504**	$ 9,267	$ 1,237

Operating income for the Unregulated Energy segment for the nine months ended September 30, 2017 was $10.5 million, an increase of $1.2 million compared to the same period in 2016. The increased operating income was due to an increase in gross margin of $8.4 million, which was partially offset by a $7.2 million increase in operating expenses.

Gross Margin

Items contributing to the period-over-period increase of $8.4 million in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2016	$ 45,380
Factors contributing to the gross margin increase for the nine months ended September 30, 2017:	
Eight Flags' CHP plant	4,186
Natural Gas Marketing	1,760
Pricing Amendments to Aspire Energy's Long-Term Agreements	1,143
Propane Wholesale Sales	728
Customer consumption - weather and other	168
Other	462
Gross margin for the nine months ended September 30, 2017	$ 53,827

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, which commenced operations in June 2016, generated $4.2 million in additional gross margin.

Natural Gas Marketing

PESCO generated additional gross margin of $1.8 million for the nine months ended September 30, 2017 compared to the same period in 2016. The increase in gross margin was generated primarily from providing natural gas to approximately 40,000 end users within one customer pool pursuant to the supplier agreement with Columbia Gas, which expired on March 31, 2017, as well as an increase in commercial and industrial customers served in Florida, offset by lower gross margin in the Mid-Atlantic region.

Pricing Amendments to Aspire Energy's Long-Term Agreements

An increase in gross margin of $1.1 million was due to favorable pricing amendments to long-term sales agreements, which generated $1.6 million in gross margin, offset by the absence of a one-time management fee of $560,000 paid to Aspire Energy by CGC in the first quarter of 2016.

Wholesale Propane Margins

Gross margin increased by $728,000, due primarily to favorable supply management activities for the Delmarva propane distribution operations.

Customer Consumption - Weather and Other

Gross margin increased by $168,000, due primarily to higher sales of propane as a result of timing of deliveries for our propane distributions operations, coupled with increased demand for propane in Florida due to weather conditions in the third quarter of 2017. This was partially offset by the impact of warmer weather primarily during the first three months of 2017.

Other Operating Expenses

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

- $2.8 million in higher operating expenses by Eight Flags' CHP plant in support of the margin generated;
- $1.5 million in higher payroll costs for additional personnel to support growth;
- $950,000 in higher benefits and employee-related costs in 2017 (since we are self-insured for healthcare, benefits costs fluctuate depending upon claims filed);
- $800,000 in higher depreciation expense, of which $424,000 relates to a credit adjustment in 2016 recorded in conjunction with the final valuation for Aspire Energy; and
- $350,000 in higher outside services costs associated primarily with growth and ongoing compliance activities.

OTHER INCOME (EXPENSE), NET

For the quarter ended September 30, 2017 compared to the quarter ended September 30, 2016

Other income (expense), net, which includes non-operating investment income (expense), interest income, late fees charged to customers and gains or losses from the sale of assets, increased by $267,000 in the third quarter of 2017, compared to the same period in 2016, due primarily to the gain from the sale of assets within our unregulated energy businesses.

For the nine months ended September 30, 2017 compared to the nine months ended September 30, 2017

Other income (expense), net, which includes non-operating investment income (expense), interest income, late fees charged to customers and gains or losses from the sale of assets, decreased by $575,000 for the first nine months of 2017, compared to the same period in 2016, due partly to costs associated with the termination of a lease for Xeron partially offset by the gain from the sale of assets within our unregulated energy businesses.

INTEREST CHARGES

For the quarter ended September 30, 2017 compared to the quarter ended September 30, 2016

Interest charges for the three months ended September 30, 2017 increased by $599,000, compared to the same period in 2016, attributable to an increase of $410,000 in interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017, and an increase of $266,000 in interest on higher short-term borrowings.

For the nine months ended September 30, 2017 compared to the nine months ended September 30, 2016

Interest charges for the nine months ended September 30, 2017 increased by $1.1 million, compared to the same period in 2016, attributable to an increase of $691,000 in interest on higher short-term borrowings and an increase of $618,000 in interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017.

INCOME TAXES

For the quarter ended September 30, 2017 compared to the quarter ended September 30, 2016

Income tax expense was $4.3 million for the three months ended September 30, 2017, compared to $3.0 million in the same period in 2016. The increase in income tax expense was due primarily to an increase in our operating results. Our effective income tax rate was 38.8 percent and 40.4 percent, for the three months ended September 30, 2017 and 2016, respectively.

For the nine months ended September 30, 2017 compared to the nine months ended September 30, 2017

Income tax expense was $20.8 million for the nine months ended September 30, 2017, compared to $21.4 million in the same period in 2016. The decrease in income tax expense was due primarily to a decrease in our operating results. Our effective income tax rate was 39.4 percent and 39.5 percent, for the nine months ended September 30, 2017 and 2016, 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 to our target capital structure.

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

Capital expenditures for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures were $132.4 million for the nine months ended September 30, 2017.

We originally budgeted $260.3 million for capital expenditures during 2017, and we currently project capital expenditures of approximately $214.7 million in 2017. Our current forecast by segment and by business line is shown below:

(dollars in thousands)	2017
Regulated Energy:	
Natural gas distribution	$ 76,771
Natural gas transmission	93,737
Electric distribution	10,768
Total Regulated Energy	181,276
Unregulated Energy:	
Propane distribution	10,458
Other unregulated energy	16,417
Total Unregulated Energy	26,875
Other:	
Corporate and other businesses	6,507
Total Other	6,507
Total 2017 Capital Expenditures	$ 214,658

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. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors.

The following table presents our capitalization, excluding and including short-term borrowings, as of September 30, 2017 and December 31, 2016:

	September 30, 2017			December 31, 2016		
(in thousands)						
Long-term debt, net of current maturities	**$**	**201,248**	**30%**	$	136,954	23%
Stockholders' equity		**463,820**	**70%**		446,086	77%
Total capitalization, excluding short-term debt	**$**	**665,068**	**100%**	$	583,040	100%

	September 30, 2017			December 31, 2016		
(in thousands)						
Short-term debt	**$**	**203,098**	**23%**	$	209,871	26%
Long-term debt, including current maturities		**213,384**	**24%**		149,053	19%
Stockholders' equity		**463,820**	**53%**		446,086	55%
Total capitalization, including short-term debt	**$**	**880,302**	**100%**	$	805,010	100%

Included in the long-term debt balances at September 30, 2017 and December 31, 2016, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement (at September 30, 2017, $1.0 million excluding current maturities and $2.4 million including current maturities, and, at December 31, 2016, $2.1 million excluding current maturities and $3.5 million including current maturities). At the closing of the ESG acquisition in May 2013, Sandpiper entered into this agreement, which has a six-year term. The capacity portion of this agreement is accounted for as a capital lease.

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 57 percent during the past three years. In September 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, which were added to our general funds and used primarily to repay a portion of our short-term debt under unsecured lines of credit.

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 the Prudential Shelf Agreement with Prudential for the potential private placement of the Prudential Shelf Notes as further described below under the heading "Shelf Agreements." In addition, we also entered into the MetLife and NYL Shelf Agreements, as described in further detail below, to have additional debt capital available to fund future growth capital expenditures.

For larger revenue-generating capital projects, 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. 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, through October 8, 2018, we may request that Prudential purchase up to $150.0 million of our 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 confirmed and accepted our request that Prudential purchase $70.0 million of 3.25 percent Prudential Shelf Notes under the Prudential Shelf Agreement. We issued the Prudential Shelf Notes on April 21, 2017 and used the proceeds to reduce short-term borrowings under the Revolver, which had increased as a result of funding capital expenditures on a temporary basis.

The Prudential Shelf Agreement sets forth certain business covenants to which we are subject when any Prudential Shelf 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.

In March 2017, we entered into the MetLife Shelf Agreement and 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 at a fixed interest rate and with 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. As of September 30, 2017, no unsecured notes have been issued under either the MetLife Shelf Agreement or the NYL Shelf Agreement.

Short-term Borrowings

Our outstanding short-term borrowings at September 30, 2017 and December 31, 2016 were $203.1 million and $209.9 million, respectively. The weighted average interest rates for our short-term borrowings were 1.96 percent and 1.49 percent, for the nine months ended September 30, 2017 and 2016, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. As of September 30, 2017, we had four unsecured bank credit facilities with three financial institutions totaling $180.0 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 $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.

None of the unsecured bank lines of credit requires compensating balances. We are currently authorized by our Board of Directors to incur up to $275.0 million of short-term borrowing.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,	
	2017	**2016**
(in thousands)		
Net cash provided by (used in):		
Operating activities	**$ 98,372**	$ 85,733
Investing activities	**(141,453)**	(109,730)
Financing activities	**42,289**	22,678
Net decrease in cash and cash equivalents	**(792)**	(1,319)
Cash and cash equivalents—beginning of period	**4,178**	2,855
Cash and cash equivalents—end of period	**$ 3,386**	$ 1,536

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 changes in deferred income taxes, depreciation 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 nine months ended September 30, 2017 and 2016, net cash provided by operating activities was $98.4 million and $85.7 million, respectively, resulting in an increase in cash flows of $12.6 million. Significant operating activities generating the cash flows change were as follows:

- Net income, adjusted for reconciling activities, increased cash flows by $17.9 million, due primarily to an increase in deferred income taxes as a result of the availability and utilization of bonus depreciation in the first nine months of 2017, which resulted in a higher book-to-tax timing difference and higher non-cash adjustments for depreciation and amortization related to increased investing activities.
- Changes in income taxes receivable decreased cash flows by $18.7 million, due to lower tax refunds during the first nine months of 2017 compared to the same period in 2016.
- Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities increased cash flows by $14.1 million, due primarily to higher revenues and the timing of the receipt of customer payments as well as the timing of payments to vendors.
- Net cash flows from changes in other inventories decreased by approximately $6.1 million, due primarily to additional pipes and other construction inventory purchases, which increased the levels of our inventory.
- Changes in net regulatory assets and liabilities increased cash flows by $4.3 million, due primarily to changes in GRIP and fuel costs collected through the various cost recovery mechanisms.
- Changes in net prepaid expenses and other current assets, customer deposits and refunds, other assets and liabilities and accrued compensation increased cash flows by $1.2 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $141.5 million and $109.7 million during the nine months ended September 30, 2017 and 2016, respectively, resulting in a decrease in cash flows of $31.8 million. Significant investing activities generating the cash flows change were as follows:

- Cash paid for capital expenditures increased by $20.5 million to $130.1 million for the first nine months of 2017, compared to $109.6 million for the same period in 2016.
- Net cash of $11.7 million was used to acquire ARM and Chipola during the first nine months of 2017; there were no corresponding transactions in 2016.

Cash Flows Used in Financing Activities

Net cash provided in financing activities totaled $42.3 million and $22.7 million during the nine months ended September 30, 2017 and 2016, respectively. The increase in net cash used in financing activities for the nine months ended September 30, 2017 resulted primarily from the following:

- We received $69.8 million in net cash proceeds from the issuance of the Prudential Shelf Notes, and we paid $2.9 million more in scheduled long-term debt principal payments and capital lease obligations payments.
- Net cash flows decreased by $57.3 million from proceeds related to the issuance of common stock during the third quarter of 2016.
- Net repayments under our line of credit arrangements of $3.8 million for the nine months ended September 30, 2017, compared to net repayments of $21.4 million for the same period in 2016, increased cash flows by $17.6 million. Change in cash overdrafts decreased cash flows by $5.5 million.
- We paid $14.8 million in cash dividends for the nine months ended September 30, 2017, compared to $13.0 million for the nine months ended September 30, 2016.

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 natural gas purchases in the event of default. PESCO has never defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at September 30, 2017 was $71.9 million, with the guarantees expiring on various dates through September 2018.

We have issued letters of credit totaling $5.8 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. These letters of credit have various expiration dates through June 2018. There have been no draws on these letters of credit as of September 30, 2017. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that they will be renewed to the extent necessary in the future. Additional information is presented in Note 5, *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 2016 Annual Report on Form 10-K, except for long-term debt, commodity purchase obligations and forward contracts entered into in the ordinary course of our business. The following table summarizes long-term debt, commodity and forward contract obligations at September 30, 2017:

	Payments Due by Period				
	Less than 1 year	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
(in thousands)					
Long-term debt [1]	$ 10,698	$ 24,226	$ 40,700	$ 135,800	**$ 211,424**
Purchase obligations - Commodity [2]	47,069	1,693	—	—	**48,762**
Total	**$ 57,767**	**$ 25,919**	**$ 40,700**	**$ 135,800**	**$ 260,186**

(1) Excludes capital lease obligation, debt issuance costs and unamortized debt discount of $1,960.

(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 September 30, 2017, we were involved in regulatory matters in each of the jurisdictions in which we operate. Our significant regulatory matters are fully described in Note 3, *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 September 30, 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 Note 13, *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 periodically adjust fuel rates to reflect changes in the wholesale cost of natural gas and electricity and to ensure that we recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers. Therefore, our regulated energy distribution operations have limited commodity price risk exposure.

Unregulated Energy Segment

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

We can store up to approximately 6.2 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate the risk of propane commodity price fluctuations on the inventory valuation, we have adopted a Risk Management Policy that allows our propane distribution operation to enter into fair value hedges, cash flows hedges or other economic hedges of our inventory.

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

PESCO is a party to natural gas futures contracts. These contracts provide PESCO with the right to purchase natural gas at a fixed price at future dates. Upon expiration, the contracts can be settled financially without taking delivery of natural gas, or PESCO can procure natural gas for its customers.

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.

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 11, *Derivative Instruments,* in the condensed consolidated financial statements.

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 September 30, 2017. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2017.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2017, 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 5, *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, 2016, 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)
July 1, 2017 through July 31, 2017 (1)	387	$ 75.75	—	—
August 1, 2017 through August 31, 2017	—	$ —	—	—
September 1, 2017 through September 30, 2017	—	$ —	—	—
Total	387	$ 75.75	—	—

(1) Chesapeake Utilities purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading "Notes to the Consolidated Financial Statements—Note 16, *Employee Benefit Plans*" in our latest Annual Report on Form 10-K for the year ended December 31, 2016. During the quarter ended September 30, 2017, 387 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.

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Item 6. Exhibits

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.

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
Senior Vice President and Chief Financial Officer

Date: November 9, 2017

EXHIBIT 31.1

CERTIFICATE PURSUANT TO RULE 13A-14(A)
UNDER THE SECURITIES EXCHANGE ACT OF 1934

I, Michael P. McMasters, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended September 30, 2017 of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d–15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2017

/S/ MICHAEL P. MCMASTERS

Michael P. McMasters
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATE PURSUANT TO RULE 13A-14(A)
UNDER THE SECURITIES EXCHANGE ACT OF 1934

I, Beth W. Cooper, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended September 30, 2017 of Chesapeake Utilities Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a–15(e) and 15d–15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d–15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2017

/S/ BETH W. COOPER

Beth W. Cooper
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

Certificate of Chief Executive Officer

of

Chesapeake Utilities Corporation

(pursuant to 18 U.S.C. Section 1350)

I, Michael P. McMasters, President and Chief Executive Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Quarterly Report on Form 10-Q of Chesapeake Utilities Corporation ("Chesapeake") for the period ended September 30, 2017, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/S/ MICHAEL P. MCMASTERS

Michael P. McMasters
November 9, 2017

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certificate of Chief Financial Officer

of

Chesapeake Utilities Corporation

(pursuant to 18 U.S.C. Section 1350)

I, Beth W. Cooper, Senior Vice President and Chief Financial Officer of Chesapeake Utilities Corporation, certify that, to the best of my knowledge, the Quarterly Report on Form 10-Q of Chesapeake Utilities Corporation ("Chesapeake") for the period ended September 30, 2017, filed with the Securities and Exchange Commission on the date hereof (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Chesapeake.

/s/ Beth W. Cooper

Beth W. Cooper

November 9, 2017

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Chesapeake Utilities Corporation and will be retained by Chesapeake Utilities Corporation and furnished to the Securities and Exchange Commission or its staff upon request.