CHESAPEAKE UTILITIES CORP
Form 10-Q
August 04, 2016
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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: June 30, 2016
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 — 15,323,102 shares outstanding as of July 31, 2016.

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GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification
ASU: Accounting Standards Update
Aspire Energy: Aspire Energy of Ohio, LLC, a wholly-owned subsidiary of Chesapeake Utilities into which Gatherco merged on April 1, 2015
CDD: Cooling degree-day, which is the measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit
Chesapeake or Chesapeake Utilities: Chesapeake Utilities Corporation, its divisions and its 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
CHP: A combined heat and power plant constructed by Eight Flags in Nassau County, Florida
Columbia Gas: Columbia Gas of Ohio
Company: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure
Credit Agreement: An agreement between Chesapeake Utilities and the lenders related to the Revolver
Deferred Compensation Plan: A non-qualified, deferred compensation arrangement under which certain of our executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors' retainers
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
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
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
FDOT: Florida Department of Transportation
FGT: Florida Gas Transmission Company
FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake Utilities

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FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake Utilities
FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake Utilities
GAAP: Accounting principles generally accepted in the United States of America
Gatherco: Gatherco, Inc.
GRIP: The Gas Reliability Infrastructure Program is a natural gas pipeline replacement program in Florida, pursuant to which we collect a surcharge from certain of our Florida customers to recover capital and other program-related costs associated with the replacement of qualifying distribution mains and services in Florida
Gulf Power: Gulf Power Company
Gulfstream: Gulfstream Natural Gas System, LLC
HDD: Heating degree-day, which is a measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is below 65 degrees Fahrenheit
JEA: The community-owned utility located in Jacksonville, Florida, formerly known as Jacksonville Electric Authority
Lenders: PNC, Bank of America N.A., Citizens Bank N.A., Royal Bank of Canada, and Wells Fargo Bank, National Association, which are collectively the lenders that entered into the Credit Agreement with Chesapeake Utilities on October 8, 2015
MDE: Maryland Department of Environment
MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use
NAM: Natural Attenuation Monitoring
NYSE: New York Stock Exchange
OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, an Eastern Shore firm transportation service that allows Eastern Shore not to schedule service for up to 90 days during the peak months of November through April
OTC: Over-the-counter
Peninsula Pipeline: Peninsula Pipeline Company, Inc., our wholly-owned Florida intrastate pipeline subsidiary
PESCO: Peninsula Energy Services Company, Inc., our wholly-owned natural gas marketing subsidiary
PNC: PNC Bank, National Association, the administrative agent and primary lender for our Revolver
Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the Shelf Agreement for the potential future purchase of our Shelf Notes
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
Revolver: The unsecured revolving credit facility issued to us by the Lenders
Sandpiper: Sandpiper Energy, Inc., a wholly-owned subsidiary of Chesapeake Utilities providing a tariff-based distribution service to customers in Worcester County, Maryland
Sanford Group: FPU and other responsible parties involved with the Sanford environmental site
SCO supplier agreement: Standard Choice Offer (SCO) supplier agreement between PESCO and Columbia Gas
SEC: Securities and Exchange Commission
Sharp: Sharp Energy, Inc., our wholly-owned propane distribution subsidiary

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Shelf Agreement: An agreement entered into by Chesapeake Utilities and Prudential pursuant to which Chesapeake Utilities may request that Prudential purchase, by October 8, 2018, up to $150.0 million of Shelf Notes at a fixed interest rate and with a maturity date not to exceed twenty years from the date of issuance
Shelf Notes: Unsecured senior promissory notes that we may request Prudential to purchase under the Shelf Agreement
SICP: 2013 Stock and Incentive Compensation Plan
TETLP: Texas Eastern Transmission, LP
Xeron: Xeron, Inc., our propane wholesale marketing subsidiary, based in Houston, Texas

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PART I—FINANCIAL INFORMATION
Item 1. Financial Statements
Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated Energy	$67,395	$ 62,060	$156,611	$171,642
Unregulated Energy and other	34,947	30,622	92,027	91,121
Total Operating Revenues	102,342	92,682	248,638	262,763
Operating Expenses				
Regulated Energy cost of sales	21,635	21,124	56,540	78,253
Unregulated Energy and other cost of sales	22,934	20,272	56,958	55,507
Operations	28,087	26,190	55,246	53,133
Maintenance	2,904	2,727	5,383	5,431
Gain from a settlement	(130)	(1,500)	(130)	(1,500)
Depreciation and amortization	7,780	7,543	15,283	14,518
Other taxes	3,390	3,156	7,236	6,743
Total Operating Expenses	86,600	79,512	196,516	212,085
Operating Income	15,742	13,170	52,122	50,678
Other Expense, net	(8)	(171)	(42)	(38)
Interest charges	2,624	2,485	5,274	4,933
Income Before Income Taxes	13,110	10,514	46,806	45,707
Income taxes	5,081	4,220	18,410	18,304
Net Income	$8,029	$ 6,294	$28,396	$27,403
Weighted Average Common Shares Outstanding:				
Basic	15,315,020	15,235,860	15,300,931	14,922,094
Diluted	15,352,702	15,280,657	15,342,287	14,970,190
Earnings Per Share of Common Stock:				
Basic	$0.52	$ 0.41	$1.86	$1.84
Diluted	$0.52	$ 0.41	$1.85	$1.83
Cash Dividends Declared Per Share of Common Stock	$0.3050	$ 0.2875	$0.5925	$0.5575

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

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
(in thousands)				
Net Income	$8,029	$6,294	$28,396	$27,403
Other Comprehensive Income (Loss), net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of $(8), $(7), $(16) and $(14), respectively	(12)	(10)	(24)	(20)
Net gain, net of tax of $67, $62, $133 and $125, respectively	99	93	200	185
Cash Flow Hedges, net of tax:				
Unrealized gain on commodity contract cash flow hedges, net of tax of $313, $4, $322 and $21, respectively	496	6	496	32
Total Other Comprehensive Income	583	89	672	197
Comprehensive Income	$8,612	$6,383	$29,068	$27,600

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

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

Assets	June 30, 2016	December 31, 2015
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	$868,016	$842,756
Unregulated Energy	189,034	145,734
Other businesses and eliminations	19,608	18,999
Total property, plant and equipment	1,076,658	1,007,489
Less: Accumulated depreciation and amortization	(229,826)	(215,313)
Plus: Construction work in progress	61,975	62,774
Net property, plant and equipment	908,807	854,950
Current Assets		
Cash and cash equivalents	3,266	2,855
Accounts receivable (less allowance for uncollectible accounts of $631 and $909, respectively)	41,851	41,007
Accrued revenue	8,658	12,452
Propane inventory, at average cost	4,285	6,619
Other inventory, at average cost	4,025	3,803
Regulatory assets	7,042	8,268
Storage gas prepayments	5,014	3,410
Income taxes receivable	7,395	24,950
Prepaid expenses	4,184	7,146
Mark-to-market energy assets	405	153
Other current assets	771	1,044
Total current assets	86,896	111,707
Deferred Charges and Other Assets		
Goodwill	15,070	14,548
Other intangible assets, net	2,033	2,222
Investments, at fair value	4,325	3,644
Regulatory assets	76,563	77,519
Receivables and other deferred charges	3,353	2,831
Total deferred charges and other assets	101,344	100,764
Total Assets	$1,097,047	$1,067,421

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

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

Capitalization and Liabilities	June 30, 2016	December 31, 2015
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	$ 7,456	$ 7,432
Additional paid-in capital	191,776	190,311
Retained earnings	185,490	166,235
Accumulated other comprehensive loss	(5,168)	(5,840)
Deferred compensation obligation	2,452	1,883
Treasury stock	(2,452)	(1,883)
Total stockholders' equity	379,554	358,138
Long-term debt, net of current maturities	143,865	149,006
Total capitalization	523,419	507,144
Current Liabilities		
Current portion of long-term debt	12,075	9,151
Short-term borrowing	180,042	173,397
Accounts payable	35,496	39,300
Customer deposits and refunds	27,572	27,173
Accrued interest	1,250	1,311
Dividends payable	4,673	4,390
Accrued compensation	6,742	10,014
Regulatory liabilities	6,808	7,365
Mark-to-market energy liabilities	256	433
Other accrued liabilities	8,978	7,059
Total current liabilities	283,892	279,593
Deferred Credits and Other Liabilities		
Deferred income taxes	199,623	192,600
Regulatory liabilities	43,093	43,064
Environmental liabilities	8,765	8,942
Other pension and benefit costs	32,695	33,481
Deferred investment tax credits and other liabilities	5,560	2,597
Total deferred credits and other liabilities	289,736	280,684
Environmental and other commitments and contingencies (Note 5 and 6)		
Total Capitalization and Liabilities	$ 1,097,047	$ 1,067,421

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

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

	Six Months Ended June 30,	
	2016	2015
(in thousands)		
Operating Activities		
Net income	$28,396	$27,403
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	15,283	14,518
Depreciation and accretion included in other costs	3,436	3,486
Deferred income taxes, net	6,162	(1,366)
Realized (gain) loss on commodity contracts/sale of assets/investments	664	(686)
Unrealized gain on investments/commodity contracts	(42)	(187)
Employee benefits and compensation	760	601
Share-based compensation	1,264	947
Other, net	24	8
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	2,264	20,194
Propane inventory, storage gas and other inventory	663	4,405
Regulatory assets/liabilities, net	519	12,728
Prepaid expenses and other current assets	2,878	3,261
Accounts payable and other accrued liabilities	(4,069)	(16,359)
Income taxes receivable	20,680	19,300
Customer deposits and refunds	399	(3,748)
Accrued compensation	(3,340)	(3,788)
Other assets and liabilities, net	(1,786)	(315)
Net cash provided by operating activities	74,155	80,402
Investing Activities		
Property, plant and equipment expenditures	(70,045)	(57,350)
Proceeds from sales of assets	89	49
Acquisitions, net of cash acquired	—	(20,930)
Environmental expenditures	(177)	(73)
Net cash used in investing activities	(70,133)	(78,304)
Financing Activities		
Common stock dividends	(8,453)	(7,532)
Issuance of stock for Dividend Reinvestment Plan	429	417
Change in cash overdrafts due to outstanding checks	1,473	2,367
Net borrowing (repayment) under line of credit agreements	5,166	4,114
Repayment of long-term debt and capital lease obligation	(2,226)	(3,934)
Net cash used in financing activities	(3,611)	(4,568)
Net Increase (Decrease) in Cash and Cash Equivalents	411	(2,470)
Cash and Cash Equivalents—Beginning of Period	2,855	4,574
Cash and Cash Equivalents—End of Period	$3,266	$2,104

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

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Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

	Common Stock							
(in thousands, except shares and per share data)	Number of Shares[1]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balance at December 31, 2014	14,588,711	$7,100	$156,581	$142,317	$ (5,676)	$ 1,258	$(1,258)	$300,322
Net income		—	—	41,140	—	—	—	41,140
Other comprehensive loss	—	—	—	—	(164)	—	—	(164)
Dividend declared ($1.1325 per share)	—	—	—	(17,222)	—	—	—	(17,222)
Retirement savings plan and dividend reinvestment plan	43,275	21	2,214	—	—	—	—	2,235
Common stock issued in acquisition	592,970	289	29,876					30,165
Share-based compensation and tax benefit [2] [3]	45,703	22	1,640	—	—	—	—	1,662
Treasury stock activities	—	—	—	—	—	625	(625)	—
Balance at December 31, 2015	15,270,659	7,432	190,311	166,235	(5,840)	1,883	(1,883)	358,138
Net income	—	—	—	28,396	—	—	—	28,396
Other comprehensive income	—	—	—	—	672	—	—	672
Dividend declared ($0.5925 per share) and dividend reinvestment plan	13,120	6	759	(9,141)	—	—	—	(8,376)
Share-based compensation and tax benefit [2] [3]	36,099	18	706	—	—	—	—	724
Treasury stock activities	—	—	—	—	—	569	(569)	—
Balance at June 30, 2016	15,319,878	$7,456	$191,776	$185,490	$ (5,168)	$ 2,452	$(2,452)	$379,554

(1) Includes 79,658 and 70,631 shares at June 30, 2016 and December 31, 2015, respectively, held in a Rabbi Trust related to our Deferred Compensation Plan.
(2) Includes amounts for shares issued for Directors' compensation.
(3) The shares issued under the SICP are net of shares withheld for employee taxes. For the six months ended June 30, 2016, and for the year ended December 31, 2015, we withheld 12,031 and 12,620 shares, respectively, for taxes.

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

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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, 2015. 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 balance sheet as of December 31, 2015. We have revised the condensed consolidated statement of cash flows for the six months ended June 30, 2015 to reflect only property, plant and equipment expenditures paid in cash within the Investing Activities section. The non-cash expenditures previously included in that section have now been included in the change in accounts payable and other accrued liabilities amount within the Operating Activities section. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

FASB Statements and Other Authoritative Pronouncements

Recently Adopted Accounting Standards

Interest - Imputation of Interest (ASC 835-30) - In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. This standard requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. ASU 2015-03 became effective for us on January 1, 2016, and we applied the provisions of this standard on a retrospective basis. As a result of the adoption of this standard, debt issuance costs totaling $312,000 and $333,000 at June 30, 2016 and December 31, 2015, respectively, previously presented as other deferred charges, a non-current asset, are now presented as a deduction from long-term debt, net of current maturities in our condensed consolidated balance sheets.

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

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

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

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Balance Sheet Classification of Deferred Taxes (ASC 740) - In November 2015, the FASB issued ASU 2015-17, Balance Sheet Classification of Deferred Taxes, which requires all deferred assets and liabilities along with any related valuation allowance to be classified as noncurrent on the balance sheet for our annual financial statements beginning January 1, 2017 and for our interim financial statements beginning January 1, 2018; however, early adoption is permitted. We adopted this standard in the first quarter of 2016 on a retrospective basis and adjusted the December 31, 2015 balance sheet by eliminating the current deferred income taxes asset and decreasing the noncurrent deferred income taxes liability by $831,000.

Recent Accounting Standards Yet to be Adopted

Revenue from Contracts with Customers (ASC 606) - In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. This standard provides a single comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, as well as across industries and capital markets. The standard contains principles that entities will apply to determine the measurement of revenue and when it is recognized. On July 9, 2015, the FASB affirmed its proposal to defer the implementation of this standard by one year. For public entities, this standard is effective for 2018 interim and annual financial statements. We are assessing the impact this standard may have on our financial position and results of operations.

Inventory (ASC 330) - In July 2015, the FASB issued ASU 2015-11, Inventory. Under this guidance, inventories are required to be measured at the lower of cost or net realizable value. Net realizable value represents the estimated selling price less costs associated with completion, disposal and transportation. ASU 2015-11 will be effective for our interim and annual financial statements issued beginning January 1, 2017; however, early adoption is permitted. The standard is to be adopted on a prospective basis. We are assessing the impact this standard may have on our financial position and results of operations.

Leases (ASC 842) - In February 2016, the FASB issued ASU 2016-02, Leases, which provides updated guidance regarding accounting for leases. This update requires a lessee to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. ASU 2016-02 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted. This update will be applied using a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We are evaluating the effect of this update on our financial position and results of operations.

Compensation (ASC 718) - In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, which simplifies several aspects of accounting for employee share-based payment transactions, including accounting for income taxes, forfeitures, and statutory tax withholding requirements, and classification in the statement of cash flows. ASU 2016-09 will be effective for our annual and interim financial statements beginning January 1, 2017, although early adoption is permitted. The amendments included in this update are to be applied prospectively except for changes impacting the presentation of the cash flow statement that can be applied prospectively or retrospectively. We are evaluating the effect of this update on our financial position and results of operations.

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2. Calculation of Earnings Per Share

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	$8,029	$ 6,294	$28,396	$ 27,403
Weighted average shares outstanding	15,315,020	15,235,860	15,300,931	14,922,094
Basic Earnings Per Share	$0.52	$ 0.41	$1.86	$ 1.84
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	$8,029	$ 6,294	28,396	27,403
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	15,315,020	15,235,860	15,300,931	14,922,094
Effect of dilutive securities:				
Share-based compensation	37,682	44,797	41,356	48,096
Adjusted denominator—Diluted	15,352,702	15,280,657	15,342,287	14,970,190
Diluted Earnings Per Share	$0.52	$ 0.41	$1.85	$ 1.83

3. Acquisitions

Gatherco Merger

On April 1, 2015, we completed the merger in which Gatherco merged with and into Aspire Energy, our then newly formed, wholly-owned subsidiary. Aspire Energy is an unregulated natural gas infrastructure company with approximately 2,500 miles of pipeline systems in 40 counties throughout Ohio. The majority of Aspire Energy's margin is derived from long-term supply agreements with Columbia Gas of Ohio and Consumers Gas Cooperative, which together serve more than 20,000 end-use customers. Aspire Energy sources gas primarily from 300 conventional producers. Aspire Energy also provides gathering and processing services necessary to maintain quality and reliability to its wholesale markets.

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

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

The merger agreement provided for additional contingent cash consideration to Gatherco's shareholders of up to $15.0 million based on a percentage of revenue generated from potential new gathering opportunities during the five-year period following the closing. As of June 30, 2016, there have been no related gathering opportunities developed; therefore, no contingent consideration liability has been recorded. Based on the absence of related gathering opportunities being developed as of June 30, 2016, we are unable to estimate the range of undiscounted contingent liability outcomes at this time.

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We incurred $1.3 million in transaction costs associated with this merger, $786,000 of which we incurred in 2014, and the remaining $514,000 we incurred during 2015. Transaction costs were included in operations expense in the accompanying condensed consolidated statements of income. The revenue and net income from this merger for the three months ended June 30, 2016, included in our condensed consolidated statements of income, were $4.8 million and $28,000, respectively. The revenue and net income from this merger for the six months ended June 30, 2016, included in our condensed consolidated statements of income, were $12.8 million and $1.7 million, respectively. This merger was accretive to earnings per share in the first full year of operations, generating $0.03 in additional earnings per share.

The purchase price allocation of the Gatherco merger was as follows:

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

The excess of the purchase price over the estimated fair values of the assets acquired and the liabilities assumed was recognized as goodwill at the merger date. The goodwill reflects the value paid primarily for opportunities for growth in a new, strategic geographic area. All of the goodwill from this merger was recorded in the Unregulated Energy segment and is not expected to be deductible for income tax purposes.

In December 2015 and during the first quarter of 2016, we adjusted the allocation of the purchase price based on additional information available. The adjustments resulted in a change in the fair value of property, plant and equipment, deferred income tax liabilities, inventory, income taxes receivable and other current liabilities. Goodwill from the merger decreased from $11.1 million to $10.1 million after incorporating these adjustments. The allocation of the purchase price and valuation of assets are final. The valuation of additional contingent cash consideration may be adjusted as additional information becomes available.

4. Rates and Other Regulatory Activities

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

Delaware

Rate Case Filing: On December 21, 2015, our Delaware division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. We proposed an increase of approximately $4.7 million, or nearly ten percent, in our revenue requirement based on the test period ending March 31, 2016. We also proposed new service offerings to promote growth and a revenue normalization mechanism for residential and small commercial customers. We expect a decision on the application during the first quarter of 2017. Pending the decision, our Delaware division increased rates on an interim basis based on the $2.5 million annualized interim rates approved by the Delaware PSC, effective February 19, 2016. We recognized incremental revenue of approximately $555,000 ($332,000 net of tax) and $878,000 ($526,000 net of tax) for the three and six months ended June 30, 2016, respectively. In addition, our Delaware division requested and received approval on July 26, 2016 from the Delaware PSC to implement revised interim rates of $4.7 million annualized for usage on and after August 1, 2016. Revenue collected prior to a final Delaware PSC decision is subject to refund. Although the final decision is expected during the first quarter of 2017, we cannot predict the revenue requirement the Delaware PSC will ultimately authorize or forecast the timing of a final decision. These rates, which are subject to refund, represent a five percent increase over current rates.

Maryland

Sandpiper Rate Case Filing: On December 1, 2015, Sandpiper filed an application with the Maryland PSC for a base rate increase and certain other changes to its tariff. We proposed an increase of $950,000, or approximately five percent, in our revenue requirement, based on the test period ended December 31, 2015. We also proposed a stratification of rate classes, based on cost of service, and a revenue normalization mechanism for residential and small commercial customers. The procedural schedule was suspended in early May 2016 to allow for the continuation of settlement discussions between Sandpiper, Maryland PSC Staff and Maryland Office of People's Counsel. We expect a decision on the application during the third quarter of 2016.

Florida

On September 1, 2015, FPU’s electric division filed to recover the cost of the proposed Florida Power & Light Company interconnect project through FPU's annual Fuel and Purchased Power Cost Recovery Clause filing. The interconnect project will enable FPU's electric division to negotiate a new power purchase agreement that will mitigate fuel costs for its Northeast division. This action was approved by the Florida PSC at its Agenda Conference held on December 3, 2015. On January 22, 2016, the Office of Public Counsel filed an appeal of the Florida PSC's decision with the Florida Supreme Court. Legal briefs have been filed, but no decision has been reached at this time.

On February 2, 2016, FPU’s natural gas division filed a petition with the Florida PSC for approval of an amendment to its existing transportation agreement with the City of Lake Worth, located in Palm Beach County, Florida. The amendment allows the city to resell natural gas distributed by FPU to the city’s compressed natural gas station. The city will then resell the natural gas, after compression, to its customers. The amendment to the transportation agreement was approved by the Florida PSC at its Agenda Conference held April 5, 2016.

On April 11, 2016, FPU’s natural gas divisions and Chesapeake Utilities' Florida division filed a joint petition for approval to allow FPU and Chesapeake Utilities to expand the cost allocation of the intrastate and unreleased capacity-related components currently embedded in the purchased gas adjustment and operational balancing account, which is currently allocated to a limited number of customers. The proposed new allocation of these costs would include additional customers, primarily transportation customers, benefiting from these costs but not currently paying for them. We expect the petition to be approved by the Florida PSC in late 2016.

Eastern Shore

White Oak Mainline Expansion Project: On November 21, 2014, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate certain expansion facilities designed to provide 45,000 Dts/d of firm transportation service to an electric power generator in Kent County, Delaware. Eastern Shore proposes to construct approximately 7.2 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and 3,550 horsepower of additional compression at Eastern Shore’s existing Delaware City compressor station in New Castle County, Delaware.

On January 22, 2015, the FERC issued a notice of intent to prepare an environmental assessment for this project. In February, April and May 2015, Eastern Shore filed environmental data in response to comments regarding the evaluation of alternate routes for a segment of the pipeline route in the vicinity of the Historic District of Kemblesville, Pennsylvania. On June 2, 2015, a field meeting was conducted to review the proposed route and alternate routes. In response to comments received from the National Park Service and other stakeholders, the FERC requested that Eastern Shore conduct an additional investigation in relation to Eastern Shore's existing right-of-way. On July 9, 2015, the FERC issued a 30-day public scoping notice, in advance of issuing an environmental assessment, in order to solicit comments from the public regarding construction of the Kemblesville loop. On August 18, 2015, Eastern Shore submitted supplemental information to the FERC regarding the results of its investigation of the Kemblesville loop.

On November 18, 2015, Eastern Shore filed an amendment to this application, which indicated the preferred pipeline route and shortened the total miles of the proposed pipeline to 5.4 miles. On February 10, 2016, the FERC issued a notice combining the White Oak Mainline Expansion Project and the System Reliability Project into a single environmental assessment. On March 2, 2016, the FERC issued a revised notice, rescheduling the issuance of the combined environmental assessment to April 25, 2016, with a 90-day authorization decision to be issued no later than July 24, 2016.

On March 28, 2016, subsequent to the issuance of the schedule, the FERC issued another environmental data request concerning the United States Department of Agriculture and an agricultural conservation easement on a tract of land where the White Oak Mainline Project would install a portion of the pipeline in its existing right-of way. On April 4, 2016, Eastern Shore responded to the data request. Subsequently, Eastern Shore revised the construction workspace configuration to mutual agreement of both parties.

On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed White Oak Mainline Project. The FERC denied Eastern Shore’s request for a pre-determination of rolled-in rate treatment and requires Eastern Shore to comply with 19 environmental conditions.

System Reliability Project: On May 22, 2015, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore’s customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days in 2014 and 2015. Since the project is intended to improve system reliability, Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project.
On June 8, 2015, the FERC filed a notice of the application, and the comment period ended on June 29, 2015. Two interested parties filed comments and protests with the FERC. Eastern Shore has filed answers to the comments and protests from the two parties.

On September 4, 2015, the FERC issued a notice of intent to prepare an environmental assessment, and Eastern Shore responded to the FERC Staff's environmental data requests. On February 10, 2016, the FERC issued a notice combining the System Reliability Project and White Oak Mainline Expansion project into a single environmental assessment. On March 2, 2016, the FERC issued a revised notice rescheduling the issuance of the combined environmental assessment to April 25, 2016, with the 90-day authorization decision to be issued no later than July 24, 2016. On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed System Reliability Project. The FERC granted Eastern Shore’s request for a pre-determination of rolled-in rate treatment in its next rate base proceeding and requires Eastern Shore to comply with 19 environmental conditions.

TETLP Capacity Expansion Project: On October 13, 2015, Eastern Shore submitted an application to the FERC to make certain measurement and related improvements at its TETLP interconnect facilities, which would enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. On December 22, 2015, the FERC authorized Eastern Shore to proceed with the project. On March 11, 2016, the capacity expansion project was placed into service.

2017 Expansion Project: On May 12, 2016, Eastern Shore submitted a request to the FERC to initiate the FERC’s pre-filing review procedures for Eastern Shore's 2017 expansion project. The expansion project consists of approximately 33 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional 3,550 horsepower compressor unit at Eastern Shore’s existing Daleville compressor station in Chester County, Pennsylvania; and approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. The expansion project is necessary to provide up to 86,437 Dts/d of additional firm natural gas transportation capacity to meet anticipated market demand. On May 17, 2016, the FERC approved Eastern Shore's request to commence the pre-filing review process. Eastern Shore is currently working through the pre-filing process and anticipates filing a certificate of public convenience and necessity seeking authorization to construct the project in November 2016.

2017 Rate Case Filing
In January 2017, Eastern Shore intends to file a base rate proceeding with the FERC as required by the terms of its 2012 settlement agreement.

5. Environmental Commitments and Contingencies

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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 June 30, 2016, we had approximately $9.9 million in environmental liabilities, representing our estimate of the future costs associated with all of FPU’s MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to all of its MGP sites, approximately $10.3 million of which has been recovered as of June 30, 2016, leaving approximately $3.7 million in regulatory assets for future recovery of environmental costs from FPU’s customers.

In addition to the FPU MGP sites, we had $314,000 in environmental liabilities at June 30, 2016 related to Chesapeake Utilities' MGP sites in Salisbury, Maryland and Winter Haven, Florida, representing our estimate of future costs associated with these sites. As of June 30, 2016, we had approximately $29,000 in regulatory and other assets for future recovery through Chesapeake Utilities' rates.

During the first quarter of 2015, we established $273,000 in environmental liabilities related to Chesapeake Utilities' MGP site in Seaford, Delaware, representing our estimate of future costs associated with this site, and recorded a regulatory asset for the same amount for probable future recovery through Chesapeake Utilities' rates via our environmental rider. On February 23, 2016, the Delaware PSC approved an environmental surcharge for the recovery of Chesapeake Utilities' environmental expenses associated with the Seaford site for the period of October 1, 2014 through September 30, 2015. Chesapeake Utilities will file for recovery of its expenses incurred between October 1, 2015 and September 30, 2016 by October 31, 2016. As of June 30, 2016, we had approximately $177,000 in environmental liabilities and $268,000 in regulatory and other assets related to this site.

Environmental liabilities for all of our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental remediation and related activities, including any potential future remediation costs for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated a MGP. FPU is implementing a remedial plan approved by the FDEP for the east parcel of the West Palm Beach site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. The Start-Up and Monitoring Report, dated November 30, 2015, was submitted for review and comment. We received a letter dated January 6, 2016 from FDEP, which provided minor comments. On January 12, 2016, FDEP conducted a facility inspection and found no problems or deficiencies.

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

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Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of this former MGP site. In January 2007, FPU and the Sanford Group signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of June 30, 2016, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

In December 2014, the EPA issued a preliminary close-out report, documenting the completion of all physical remedial construction activities at the Sanford site. Groundwater monitoring and statutory five-year reviews to ensure performance of the approved remedy will continue on this site. The total cost of the final remedy is estimated to be over $20.0 million, which includes long-term monitoring and the settlement of claims asserted by two adjacent property owners to resolve damages that the property owners allege they have incurred and will incur as a result of the implementation of the EPA-approved remediation.

In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims. FPU advised the other members of the Sanford Group that it is unwilling to pay any sum in excess of the $650,000 committed by FPU in the Third Participation Agreement. The Sanford Group has not requested that FPU contribute to costs beyond the originally agreed upon $650,000 contribution.

As of June 30, 2016, FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be $24,000. We are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU's asserted defense as to its limited liability for future costs exceeding $13.0 million to implement the final remedy for this site, as provided for in the Third Participation Agreement, or whether the other members of the Sanford Group will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid pursuant to the Third Participation Agreement. No such claims have been made as of June 30, 2016.

Key West, Florida

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

In October 2012, FDEP issued a RAP approval order, which requires a limited semi-annual NAM. The most recent groundwater-monitoring event was conducted in March 2016. Natural attenuation default criteria were met at all locations sampled and the semi-annual report was submitted on April 18, 2016. FDEP responded with an acceptance letter on April 22, 2016, concurring with FPU's consultant's recommendation that semi-annual monitoring should continue at this facility, with the next semi-annual NAM scheduled for the third quarter of 2016.

Although the duration of the FDEP-required limited NAM cannot be determined with certainty, we anticipate that total costs to complete the remedial action will not exceed $50,000. The annual cost to conduct the limited NAM program is not expected to exceed $8,000.

Pensacola, Florida

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

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Winter Haven, Florida

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

Groundwater monitoring results on the southern portion of this site indicate that natural attenuation default criteria continue to be exceeded. Plans to modify the monitoring network on the southern portion of the site in order to collect additional data to support the development of a remedial plan were specified in a letter to FDEP, dated October 17, 2014. The well installation and abandonment program was implemented in October 2014, and documentation was reported in the next semi-annual RAP implementation status report, submitted on January 8, 2015. FDEP approved the plan to expand the bio-sparging operations in the southern portion of the site, and additional sparge points were installed and connected to the operating system in the first quarter of 2016.

Although specific remedial actions for the site have not yet been identified, we estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $425,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site. We continue to believe that the entire amount will be recoverable from customers through rates.

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

Salisbury, Maryland

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

Seaford, Delaware

In a letter dated December 5, 2013, DNREC notified us that it would be conducting a facility evaluation of a former MGP site in Seaford, Delaware. In a report issued in January 2015, DNREC provided the evaluation, which found several compounds within the groundwater and soil that require further investigation. On September 17, 2015, DNREC approved our application to enter this site into the voluntary cleanup program. A remedial investigation was conducted in December 2015, and the resulting remedial investigation report was submitted to DNREC in May 2016. Based on findings from the remedial investigation, DNREC requested additional investigative work be performed prior to approval of potential remedial actions. We anticipate completing this additional investigative work by the end of 2016. We estimate the cost of potential remedial actions, based on the findings of the DNREC report, to be between $273,000 and $465,000. We also believe these costs will be recoverable from customers through rates.

Cambridge, Maryland

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

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Ohio

We have completed the investigation, assessment and remediation of eight natural gas pipeline facilities in Ohio that Aspire Energy acquired from Gatherco pursuant to the merger. Gatherco's indemnification obligations for environmental matters apply to remediation costs in excess of a $431,250 deductible and are capped at $1.7 million. Pursuant to the merger agreement, an escrow was established to fund certain claims by Chesapeake Utilities and Aspire Energy for indemnification by Gatherco, including environmental claims. The costs incurred to date associated with remediation activities for these eight facilities is approximately $1.6 million. We have recorded a receivable for the costs incurred, net of the deductible amount, and have submitted our request for reimbursement to the escrow agent. Negotiations are currently underway.

6. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase natural gas, electricity and propane from various suppliers. The contracts have various expiration dates. For our Delaware and Maryland natural gas distribution divisions, we have a contract with an unaffiliated energy marketing and risk management company to manage a portion of their natural gas transportation and storage capacity, which expires on March 31, 2017.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with EGWIC to purchase propane over a six-year term, or until May 2019. Sandpiper's current annual commitment is estimated at approximately 6.5 million gallons. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices.

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC over a six-year term, or until May 2019. Sharp's current annual commitment is estimated at approximately 6.5 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC, and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified in the other agreement.

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

In May 2015, PESCO renewed contracts to purchase natural gas from various suppliers for a one-year term, expiring May 2016, with the total monthly purchase commitment ranging from 9,982 to 13,423 Dts/d. PESCO has renewed these contracts for an additional six-month term, expiring October 2016.

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 FPU fails to comply with either of these ratios, it has 30 days to cure the default or, if the default is not cured, to provide an irrevocable letter of credit. 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 either of these ratios, 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 June 30, 2016, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has authorized the Company to issue corporate guarantees and to obtain letters of credit securing our subsidiaries' obligations. The maximum authorized liability under such guarantees and letters of credit is

$65.0 million.

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We have issued corporate guarantees to certain of our subsidiaries' vendors, the largest of which are for Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that Xeron or PESCO defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at June 30, 2016 was approximately $53.6 million, with the guarantees expiring on various dates through June 2017.

Chesapeake Utilities also guarantees the payment of FPU’s first mortgage bonds. The maximum exposure under this guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU’s first mortgage bonds approximate their carrying values (see Note 14, Long-Term Debt, for further details).

We issued letters of credit totaling approximately $8.1 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 March 2017. There have been no draws on these letters of credit as of June 30, 2016. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

Tax-related Contingencies

We are subject to various audits and reviews by the federal, state, local and other governmental authorities regarding income taxes and taxes other than income. As of June 30, 2016, we maintained a liability of approximately $50,000 related to unrecognized income tax benefits and approximately $72,000 related to contingencies for taxes other than income. As of December 31, 2015, we maintained a liability of approximately $50,000 related to unrecognized income tax benefits and approximately $310,000 related to contingencies for taxes other than income.

Other

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

7. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance. The segments are evaluated based on their pre-tax operating income. Our operations comprise 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 and wholesale marketing operations, and natural gas marketing operations, which are unregulated as to their rates and services. Effective April 1, 2015, this segment includes Aspire Energy, whose services include natural gas gathering, processing, transportation and supply (See Note 3, Acquisitions, regarding the merger with Gatherco). Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

The remainder of our operations is presented as “Other businesses and eliminations”, which consists of unregulated subsidiaries that own real estate leased to Chesapeake Utilities, as well as certain corporate costs not allocated to other operations.

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The following table presents financial information about our reportable segments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy segment	$66,590	$61,790	$155,483	$171,082
Unregulated Energy segment	35,752	30,892	93,155	91,681
Total operating revenues, unaffiliated customers	$102,342	$92,682	$248,638	$262,763
Intersegment Revenues [1]				
Regulated Energy segment	$805	$270	$1,128	$560
Unregulated Energy segment	1,052	1,666	1,165	1,873
Other businesses	240	220	466	440
Total intersegment revenues	$2,097	$2,156	$2,759	$2,873
Operating Income				
Regulated Energy segment	$15,226	$13,605	$39,545	$35,788
Unregulated Energy segment	412	(540)	12,347	14,689
Other businesses and eliminations	104	105	230	201
Total operating income	15,742	13,170	52,122	50,678
Other Expense, net	(8)	(171)	(42)	(38)
Interest	2,624	2,485	5,274	4,933
Income before Income Taxes	13,110	10,514	46,806	45,707
Income taxes	5,081	4,220	18,410	18,304
Net Income	$8,029	$6,294	$28,396	$27,403

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

(in thousands)	June 30, 2016	December 31, 2015
Identifiable Assets		
Regulated Energy segment	$892,513	$872,065
Unregulated Energy segment	192,654	171,840
Other businesses and eliminations	11,880	23,516
Total identifiable assets	$1,097,047	$1,067,421

Our operations are entirely domestic.

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8. Accumulated Other Comprehensive Loss

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options and natural gas futures contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss). The following tables present the changes in the balance of accumulated other comprehensive loss for the six months ended June 30, 2016 and 2015. 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, 2015	$ (5,580)	$ (260)	$(5,840)
Other comprehensive gain before reclassifications	—	525	525
Amounts reclassified from accumulated other comprehensive loss	176	(29)	147
Net current-period other comprehensive income	176	496	672
As of June 30, 2016	$ (5,404)	$ 236	$(5,168)

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2014	$ (5,643)	$ (33)	$(5,676)
Other comprehensive loss before reclassifications	—	(1)	(1)
Amounts reclassified from accumulated other comprehensive loss	165	33	198
Net prior-period other comprehensive income	165	32	197
As of June 30, 2015	$ (5,478)	$ (1)	$(5,479)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and six months ended June 30, 2016 and 2015. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

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	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
(in thousands)				
Amortization of defined benefit pension and postretirement plan items:				
Prior service cost [1]	$20	$17	$40	$34
Net loss [1]	(166)	(155)	(333)	(310)
Total before income taxes	(146)	(138)	(293)	(276)
Income tax benefit	58	55	117	111
Net of tax	$(88)	$(83)	$(176)	$(165)
Gains and losses on commodity contracts cash flow hedges				
Propane swap agreements [2]	$—	$(10)	$(322)	$2
Call options [2]	—	—	—	(55)
Natural gas futures [2]	211	—	359	—
Total before income taxes	211	(10)	37	(53)
Income tax benefit (expense)	(81)	4	(8)	21
Net of tax	130	(6)	29	(32)
Total reclassifications for the period	$42	$(89)	$(147)	$(197)

[1] These amounts are included in the computation of net periodic costs (benefits). See Note 9, Employee Benefit Plans, for additional details.
[2] These amounts are included in the effects of gains and losses from derivative instruments. See Note 12, Derivative Instruments, for additional details.
Amortization of defined benefit pension and postretirement plan items is included in operations expense, and gains and losses on propane swap agreements 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 expense in the accompanying condensed consolidated statements of income.

9. Employee Benefit Plans
Net periodic benefit costs for our pension and post-retirement benefits plans for the three and six months ended June 30, 2016 and 2015 are set forth in the following table:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended June 30,	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
(in thousands)										
Interest cost	$105	$102	$630	$626	$ 23	$ 23	$ 11	$ 11	$14	$ 15
Expected return on plan assets	(131)	(135)	(701)	(777)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	—	2	(20)	(19)	—	—
Amortization of net loss	103	91	128	114	22	25	17	17	—	2
Net periodic cost (benefit)	77	58	57	(37)	45	50	8	9	14	17
Amortization of pre-merger regulatory asset	—	—	191	191	—	—	—	—	2	2
Total periodic cost	$77	$58	$248	$154	$ 45	$ 50	$ 8	$ 9	$16	$ 19

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For the Six Months Ended June 30,	Chesapeake Pension Plan 2016	Chesapeake Pension Plan 2015	FPU Pension Plan 2016	FPU Pension Plan 2015	Chesapeake SERP 2016	Chesapeake SERP 2015	Chesapeake Postretirement Plan 2016	Chesapeake Postretirement Plan 2015	FPU Medical Plan 2016	FPU Medical Plan 2015
(in thousands)										
Interest cost	$210	$204	$1,259	$1,251	$46	$46	$21	$22	$28	$30
Expected return on plan assets	(261)	(270)	(1,402)	(1,554)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	—	5	(40)	(39)	—	—
Amortization of net loss	206	181	257	227	44	50	34	35	—	3
Net periodic cost (benefit)	155	115	114	(76)	90	101	15	18	28	33
Amortization of pre-merger regulatory asset	—	—	381	381	—	—	—	—	4	4
Total periodic cost	$155	$115	$495	$305	$90	$101	$15	$18	$32	$37

We expect to record pension and postretirement benefit costs of approximately $1.6 million for 2016. 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 $2.5 million and approximately $2.9 million at June 30, 2016 and December 31, 2015, respectively. The amortization included in pension expense is also being added to a net periodic loss of approximately $802,000, which will increase our total expected benefit costs to approximately $1.6 million.

Pursuant to a Florida PSC order, FPU continues to record as a regulatory asset a portion of the unrecognized pension and postretirement benefit costs 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 table presents 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 six months ended June 30, 2016 and 2015:

For the Three Months Ended June 30, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (20)	$ —	$ (20)
Net loss	103	128	22	17	—	270
Total recognized in net periodic benefit cost	$ 103	$ 128	$ 22	$ (3)	$ —	$ 250
Recognized from accumulated other comprehensive loss [1]	$ 103	$ 24	$ 22	$ (3)	$ —	$ 146
Recognized from regulatory asset	—	104	—	—	—	104
Total	$ 103	$ 128	$ 22	$ (3)	$ —	$ 250

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For the Three Months Ended June 30, 2015	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$ —	$ 2	$ (19)	$ —	$ (17)
Net loss	91	114	25	17	2	249
Total recognized in net periodic benefit cost	$ 91	$ 114	$ 27	$ (2)	$ 2	$ 232
Recognized from accumulated other comprehensive loss [1]	$ 91	$ 22	$ 27	$ (2)	$ —	$ 138
Recognized from regulatory asset	—	92	—	—	2	94
Total	$ 91	$ 114	$ 27	$ (2)	$ 2	$ 232

For the Six Months Ended June 30, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (40)	$ —	$ (40)
Net loss	206	257	44	34	—	$ 541
Total recognized in net periodic benefit cost	$ 206	$ 257	$ 44	$ (6)	$ —	$ 501
Recognized from accumulated other comprehensive loss [1]	$ 206	$ 49	$ 44	$ (6)	$ —	$ 293
Recognized from regulatory asset	—	208	—	—	—	208
Total	$ 206	$ 257	$ 44	$ (6)	$ —	$ 501

For the Six Months Ended June 30, 2015	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$ —	$ 5	$ (39)	$ —	$ (34)
Net loss	181	227	50	35	3	496
Total recognized in net periodic benefit cost	$ 181	$ 227	$ 55	$ (4)	$ 3	$ 462
Recognized from accumulated other comprehensive loss [1]	$ 181	$ 43	$ 55	$ (4)	$ 1	$ 276
Recognized from regulatory asset	—	184	—	—	2	186
Total	$ 181	$ 227	$ 55	$ (4)	$ 3	$ 462

[1] See Note 8, Accumulated Other Comprehensive Loss.

During the three and six months ended June 30, 2016, we contributed approximately $170,000 and $274,000, respectively, to the Chesapeake Pension Plan and approximately $548,000 and approximately $885,000, respectively, to the FPU Pension Plan. We expect to contribute a total of approximately $508,000 and approximately $1.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2016, which represent 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 six months ended June 30, 2016, were approximately $38,000 and approximately $76,000, respectively. We expect to pay total cash benefits of approximately $151,000 under the Chesapeake Pension SERP in 2016. Cash benefits paid under the Chesapeake Postretirement Plan, primarily for medical claims for the three and six months ended June 30, 2016, were approximately $15,000 and approximately $36,000, respectively. We estimate that approximately $82,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2016. Cash benefits paid under the FPU Medical

Plan, primarily for medical claims for the three and six months ended June 30, 2016, were approximately $27,000 and approximately $67,000,

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respectively. We estimate that approximately $149,000 will be paid for such benefits under the FPU Medical Plan in 2016.

10. Investments

The investment balances at June 30, 2016 and December 31, 2015, consisted of the following:

(in thousands)	June 30, 2016	December 31, 2015
Rabbi trust (associated with the Deferred Compensation Plan)	$4,304	$ 3,626
Investments in equity securities	21	18
Total	$4,325	$ 3,644

We classify these investments as trading securities and report them at their fair value. For the three months ended June 30, 2016 and 2015, we recorded a net unrealized gain of approximately $71,000 and approximately $4,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the six months ended June 30, 2016 and 2015, we recorded an unrealized gain of approximately $53,000 and approximately $107,000, respectively, in other income 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.

11. Share-Based Compensation

Our non-employee directors and key employees are granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period.

The table below presents the amounts included in net income related to share-based compensation expense for the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2016	2015	2016	2015
Awards to non-employee directors	$145	$160	$310	$311
Awards to key employees	470	250	954	636
Total compensation expense	615	410	1,264	947
Less: tax benefit	(248)	(165)	(509)	(381)
Share-based compensation amounts included in net income	$367	$245	$755	$566

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 2016, each of our non-employee directors received an annual retainer of 953 shares of common stock under the SICP for service as a director through the 2017 Annual Meeting of Stockholders.

A summary of the stock activity for our non-employee directors during the six months ended June 30, 2016 is presented below:

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	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2015	—	$ —
Granted	8,577	$ 62.90
Vested	(8,577)	$ 62.90
Outstanding— June 30, 2016	—	$ —

At June 30, 2016, there was approximately $450,000 of unrecognized compensation expense related to these awards. This expense will be recognized over the directors' remaining service period ending April 30, 2017.

Key Employees

The table below presents the summary of the stock activity for awards to key employees for the six months ended June 30, 2016:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2015	110,398	$ 38.34
Granted	46,571	$ 67.90
Vested	(39,553)	$ 31.79
Expired	(2,325)	$ 42.25
Outstanding— June 30, 2016	115,091	$ 51.85

In February 2016, our Board of Directors granted awards of 46,571 shares of common stock to key employees under the SICP. The shares granted in February 2016 are multi-year awards that will vest at the end of the three-year service period ending December 31, 2018. 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 June 30, 2016, the aggregate intrinsic value of the SICP awards granted to key employees was approximately $7.6 million. At June 30, 2016, there was approximately $3.2 million of unrecognized compensation cost related to these awards, which is expected to be recognized from 2016 through 2018.

12. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Aspire Energy has entered into contracts with producers to secure natural gas to meet its obligations. Purchases under these contracts typically either do not meet the definition of derivatives or are considered “normal purchases and 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 June 30, 2016, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2016

In June 2016, Sharp entered into a swap agreement to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons expected to be purchased for the upcoming heating season. Under the swap agreement, Sharp will receive the difference between the index prices (Mont Belvieu prices in December 2016 through February 2017) and the swap price of $0.5525 per gallon, to the extent the index prices exceed the swap price. If the index prices are lower than the swap price, Sharp will pay the difference. The swap agreement essentially fixes the price of the 630,000 gallons that we expect to purchase for the upcoming heating season. We accounted for the swap agreement as a cash flow

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hedge, and there is no ineffective portion of this hedge. At June 30, 2016, the swap agreement had a fair value of approximately $23,000. The change in the fair value of the swap agreement is recorded as unrealized gain/loss in other comprehensive income (loss).

In January 2016, PESCO entered into a SCO supplier agreement with Columbia Gas to provide natural gas supply for Columbia Gas to service one of its local distribution customer tranches. PESCO also assumed the obligation to store natural gas inventory to satisfy its obligations under the SCO supplier agreement, which terminates on March 31, 2017.

In conjunction with the SCO supplier agreement, PESCO entered into natural gas futures contracts during the second quarter of 2016 in order to protect its natural gas inventory against market price fluctuations. The contracts expire within one year. We have accounted for these contracts as fair value hedges, and any ineffective portion is reported directly in earnings. We believe these contracts are highly effective at hedging inventory. At June 30, 2016, PESCO had a total of 1,065,000 Dts/d hedged under natural gas futures contracts, with a liability fair value of approximately $233,000. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in earnings and is offset by any associated gain (loss) in the value of the inventory being hedged.

Beginning in October 2015, PESCO entered into natural gas futures contracts associated with the purchase and sale of natural gas to other specific customers. These contracts expire within two years, and we have accounted for them as cash flow hedges. There is no ineffective portion of these hedges. At June 30, 2016, PESCO had a total of 6,090,000 Dts/d hedged under natural gas futures contracts, with an asset fair value of approximately $357,000. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss).

Fair Value Hedges

The impact of our natural gas futures commodity contracts designated as fair value hedges and the related hedged item on our condensed consolidated income statement for the three and six months ended June 30, 2016 is presented below:

(in thousands)	Three Months Ended June 30, 2016[(1)]	Six Months Ended June 30, 2016[(1)]
Commodity contracts	$ (233)	$ (233)
Fair value adjustment for natural gas inventory designated as the hedged item	681	681
Total increase in purchased gas cost	$ 448	$ 448

The increase in purchased gas cost is comprised of the following:

Basis ineffectiveness	$ (83)	$ (83)
Timing ineffectiveness	531	531
Total ineffectiveness	$ 448	$ 448

(1) There were no natural gas futures commodity contracts designated as fair value hedges in 2015.

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

Hedging Activities in 2015

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

In March, May and June 2015, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 2.5 million gallons purchased in December 2015 through March 2016. Under these

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swap agreements, Sharp would have received the difference between the index prices (Mont Belvieu prices in December 2015 through March 2016) and the swap prices, which ranged from $0.5200 to $0.5950 per gallon, for each swap agreement, to the extent the index prices exceeded the swap prices. If the index prices were lower than the swap prices, Sharp would pay the difference. These swap agreements essentially fixed the price of the 2.5 million gallons that we purchased during this period. We accounted for the swap agreements as cash flow hedges. Sharp paid approximately $484,000, which represents the difference between the index prices and swap prices during those months of the swap agreements.

Commodity Contracts for Trading Activities

Xeron engages in trading activities using forward and futures contracts for propane and crude oil. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under this method, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statements of income for the period of change. As of June 30, 2016, we had the following outstanding propane and crude oil trading contracts, which we accounted for as derivatives:

At June 30, 2016	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts - Propane			
Purchase	421,000	$0.5375	$ 0.5388

At June 30, 2016	Quantity in Barrels	Estimated Market Prices	Weighted Average Contract Prices
Futures Contracts - Crude Oil			
Purchase	20,000	$48.3300	$ 47.9000

Estimated market prices and weighted average contract prices are in dollars per gallon and barrel. All contracts expire by the end of the third quarter of 2016.

Xeron entered into master netting agreements with two counterparties to mitigate exposure to counterparty credit risk. The master netting agreements enable Xeron to net these two counterparties' outstanding accounts receivable and payable, which are presented on a gross basis in the accompanying condensed consolidated balance sheets. At June 30, 2016, Xeron had no accounts receivable or accounts payable balances to offset with these two counterparties. At December 31, 2015, Xeron had a right to offset $431,000 of accounts payable with these two counterparties. At December 31, 2015, Xeron did not have outstanding accounts receivable with these two counterparties.

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency. The fair values of the derivative contracts recorded in the condensed consolidated balance sheets as of June 30, 2016 and December 31, 2015, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	June 30, 2016	December 31, 2015
Derivatives not designated as hedging instruments			
Forward & Future contracts	Mark-to-market energy assets	$25	$ 1
Derivatives designated as fair value hedges			
Put options	Mark-to-market energy assets	—	152
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Mark-to-market energy assets	357	—

Propane swap agreements	Mark-to-market energy assets	23	—
Total asset derivatives		$405	$ 153

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	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	June 30, 2016	December 31, 2015
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$23	$ 1
Derivatives designated as fair value hedges			
Natural gas futures contracts	Mark-to-market energy liabilities	233	—
Derivatives designated as cash flow hedges			
Propane swap agreements	Mark-to-market energy liabilities	—	323
Natural gas futures contracts	Mark-to-market energy liabilities	—	109
Total liability derivatives		$256	$ 433

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

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	(Loss) on Derivatives	2016	2015	2016	2015
Derivatives not designated as hedging instruments					
Realized gain on forward contracts [1]	Revenue	$ 88	$ (71)	275	206
Unrealized gain (loss) on forward contracts [1]	Revenue	1	203	2	78
Propane swap agreements	Cost of sales	—	—	—	18
Derivatives designated as fair value hedges					
Put /Call options	Cost of sales	—	—	73	506
Put /Call options [2]	Propane Inventory	—	(30)		(34)
Natural gas futures contracts	Natural Gas Inventory	(233)	—	(233)	—
Derivatives designated as cash flow hedges					
Propane swap agreements	Cost of sales	—	—	(364)	—
Propane swap agreements	Other Comprehensive Gain (Loss)	23	10	23	(2)
Call options	Cost of sales	—	—	—	(81)
Natural gas futures contracts	Cost of sales	211	—	359	—
Natural gas futures contracts	Other Comprehensive Gain	786	—	472	—
Total		$ 876	$ 112	$ 607	$ 691

(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.

13. Fair Value of Financial Instruments

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The 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:

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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 June 30, 2016 and December 31, 2015:

		Fair Value Measurements Using:		
As of June 30, 2016	Fair Value	Quoted- Prices- in Active Markets (Level 1)	Significant- Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$ 21	$21	$ —	$ —
Investments—guaranteed income fund	$ 475	$—	$ —	$ 475
Investments—mutual funds and other	$ 3,829	$3,829	$ —	$ —
Mark-to-market energy assets, incl. put options and swap agreements	$ 405	$—	$ 405	$ —
Liabilities:				
Mark-to-market energy liabilities incl. swap agreements	$ 256	$—	$ 256	$ —

		Fair Value Measurements Using:		
As of December 31, 2015	Fair Value	Quoted- Prices- in Active Markets (Level 1)	Significant- Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$ 18	$18	$ —	$ —
Investments—guaranteed income fund	$ 279	$—	$ —	$ 279
Investments—mutual funds and other	$ 3,347	$3,347	$ —	$ —
Mark-to-market energy assets, incl. put/call options	$ 153	$—	$ 153	$ —
Liabilities:				
Mark-to-market energy liabilities, incl. swap agreements	$ 433	$—	$ 433	$ —

The following valuation techniques were used to measure fair value assets in the tables above on a recurring basis as of June 30, 2016 and December 31, 2015:
Level 1 Fair Value Measurements:
Investments - equity securities — The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities.
Investments - mutual funds and other — The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.

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Level 2 Fair Value Measurements:
Mark-to-market energy assets and liabilities — These forward contracts are valued using market transactions in either the listed or OTC markets.
Propane put/call options, swap agreements and natural gas futures contracts – The fair value of the propane put/call options, swap agreements and natural gas futures contracts are measured using market transactions for similar assets and liabilities in either the listed or OTC markets.
Level 3 Fair Value Measurements:
Investments- guaranteed income fund — The fair values of these investments are recorded at the contract value, which approximates their fair value.
The following table sets forth the summary of the changes in the fair value of Level 3 investments for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
	2016	2015
(in thousands)		
Beginning Balance	$279	$287
Purchases and adjustments	112	49
Transfers	88	(3)
Distribution	(8)	—
Investment income	4	2
Ending Balance	$475	$335

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

At June 30, 2016, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.
Other Financial Assets and Liabilities
Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).
At June 30, 2016, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of approximately $151.8 million. This compares to a fair value of approximately $174.3 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, and with adjustments for duration, optionality, and risk profile. At December 31, 2015, long-term debt, including the current maturities but excluding a capital lease obligation, had a carrying value of approximately $153.7 million, compared to the estimated fair value of approximately $165.1 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

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14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	June 30, 2016	December 31, 2015
FPU secured first mortgage bonds [1] :		
9.08% bond, due June 1, 2022	$7,976	$ 7,973
Uncollateralized senior notes:		
6.64% note, due October 31, 2017	5,455	5,455
5.50% note, due October 12, 2020	10,000	10,000
5.93% note, due October 31, 2023	22,500	24,000
5.68% note, due June 30, 2026	29,000	29,000
6.43% note, due May 2, 2028	7,000	7,000
3.73% note, due December 16, 2028	20,000	20,000
3.88% note, due May 15, 2029	50,000	50,000
Promissory notes	168	238
Capital lease obligation	4,153	4,824
Total long-term debt	156,252	158,490
Less: current maturities	(12,075)	(9,151)
Less: debt issuance costs	(312)	(333)
Total long-term debt, net of current maturities	$143,865	$ 149,006

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

Shelf Agreement

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

On May 13, 2016, we formally requested that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. On May 20, 2016, Prudential formally accepted and confirmed our request. The closing of the sale and issuance of the Shelf Notes is expected to occur on or before April 28, 2017.

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

15. Short-Term Borrowing

On October 8, 2015, we entered into the Credit Agreement with the Lenders for a $150.0 million Revolver for a term of five years, subject to the terms and conditions of the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures.

Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25 percent or less. Interest will be payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We may extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each Lender. At June 30, 2016 and December 31, 2015, we had borrowed $40.0 million and $35.0 million, respectively, under the Revolver.

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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, 2015, 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 wo 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. These statements are subject to many risks, uncertainties and other important factors that could cause actual results to differ materially from those expressed in the forward-looking statements. Such factors include, but are not limited to:

- state and federal legislative and regulatory initiatives (including deregulation) that affect cost and investment recovery, have an impact on rate structures and affect the speed at, and the degree to, which competition enters the electric and natural gas industries;
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recoverable in rates;
- the timing of certification authorizations;
- the loss of customers due to a government-mandated sale of our utility distribution facilities;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now or may in the future own or operate;
- the capital-intensive nature of our regulated energy businesses;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the impact on our cost and funding obligations under our pension and other post-retirement benefit plans of potential downturns in the financial markets, lower discount rates, and costs associated with the Patient Protection and Affordable Care Act;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the extent of our success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the ability to continue to hire, train and retain appropriately qualified personnel;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to establish and maintain new key supply sources;

- the effect of spot, forward and future market prices on our various energy businesses;
- the effect of competition on our businesses;
- the ability to construct facilities at or below estimated costs;
- possible increased federal, state and local regulation of the safety of our operations;
- the inherent hazards and risks involved in our energy businesses;

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

Introduction

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

Our strategy is focused on growing earnings from a stable utility foundation and investing in related businesses and services that provide opportunities for returns greater than traditional utility returns. The key elements of this strategy include:

- executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;
- expanding the propane distribution business in existing and new markets through leveraging our community gas system services, our vehicular fuel offerings and our bulk delivery capabilities;
- expanding both our regulated and unregulated energy businesses through strategic acquisitions;
- utilizing our expertise across our various businesses to improve overall performance;
- pursuing and entering new unregulated energy markets and business lines that will complement our existing strategy and operating units;
- enhancing marketing channels to attract new customers;
- providing reliable and responsive customer service to existing customers so they become our best promoters;
- engaging our customers through a distinctive service excellence initiative;
- developing and retaining a high-performing team that advances our goals;
- empowering and engaging our employees at all levels to live our brand and vision;
- demonstrating community leadership and engaging our local communities and governments in a cooperative and mutually beneficial way;
- maintaining a capital structure that enables us to access capital as needed;
- continuing to build a branded culture that drives a shared mission, vision, and values;
- maintaining a consistent and competitive dividend for stockholders; and
- creating and maintaining a diversified customer base, energy portfolio and utility foundation.

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 the document on operating income and segment results include the use of the term “gross margin.” “Gross margin” is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased fuel cost for natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. Chesapeake Utilities believes that gross margin, although a non-GAAP measure, is meaningful in the Company's regulated operations because the cost of natural gas and electricity are passed through and changes in commodity prices can cause revenue to go up and down in ways that are not indicative of volumes sold or tied to profitability. Gross margin provides investors with information that demonstrates the profitability achieved by the Company under its allowed rates for regulated operations and under its competitive pricing structure for non-regulated segments. Chesapeake Utilities' 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.

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Results of Operations for the Three and Six Months ended June 30, 2016

Overview and Highlights

Our net income for the quarter ended June 30, 2016 was $8.0 million, or $0.52 per share. This represents an increase of $1.7 million, or $0.11 per share, compared to net income of $6.3 million, or $0.41 per share, as reported for the same quarter in 2015. Excluding the non-recurring gain associated with the billing system settlement, operating income increased $3.9 million for the three months ended June 30, 2016.

	Three Months Ended June 30, 2016	2015	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$15,226	$13,605	$ 1,621
Unregulated Energy segment	412	(540)	952
Other businesses and eliminations	104	105	(1)
Operating Income	$15,742	$13,170	$ 2,572
Other Expense, net	(8)	(171)	163
Interest Charges	2,624	2,485	139
Pre-tax Income	13,110	10,514	2,596
Income Taxes	5,081	4,220	861
Net Income	$8,029	$6,294	$ 1,735
Earnings Per Share of Common Stock			
Basic	$0.52	$0.41	$ 0.11
Diluted	$0.52	$0.41	$ 0.11

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Key variances included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Second Quarter of 2015 Reported Results	$10,514	$6,294	$ 0.41
Adjusting for Unusual Items:			
Net gain from settlement agreement associated with customer billing system	(1,370)	(820)	(0.05)
	(1,370)	(820)	(0.05)
Increased (Decreased) Gross Margins:			
Service expansions (See Major Projects and Initiatives table)	1,992	1,192	0.08
GRIP	1,040	623	0.04
Natural gas growth (excluding service expansions)	820	491	0.03
Aspire Energy	708	424	0.03
Implementation of Delaware division interim rates	555	332	0.02
Eight Flags	551	330	0.02
Natural gas marketing	464	278	0.02
Increase in customer consumption	345	207	0.01
	6,475	3,877	0.25
Decreased (Increased) Other Operating Expenses:			
Higher payroll and benefit costs	(1,100)	(658)	(0.04)
Higher service contractor costs	(786)	(470)	(0.03)
Higher depreciation, asset removal, amortization and property tax costs due to recent capital investments	(493)	(295)	(0.02)
	(2,379)	(1,423)	(0.09)
Interest Charges	(139)	(83)	(0.01)
Net Other Changes	9	184	0.01
Second Quarter of 2016 Reported Results	$13,110	$8,029	$ 0.52

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Our net income for the six months ended June 30, 2016 was $28.4 million, or $1.85 per share. This represents an increase of $993,000, or $0.02 per share, compared to net income of $27.4 million, or $1.83 per share, as reported for the same period in 2015. Excluding the non-recurring gain associated with the billing system settlement, operating income increased by $2.8 million for the six months ended June 30, 2016.

	Six Months Ended June 30,		Increase (decrease)
	2016	2015	
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$39,545	$35,788	$ 3,757
Unregulated Energy segment	12,347	14,689	(2,342)
Other businesses and eliminations	230	201	29
Operating Income	$52,122	$50,678	1,444
Other Expense, net	(42)	(38)	(4)
Interest Charges	5,274	4,933	341
Pre-tax Income	46,806	45,707	1,099
Income Taxes	18,410	18,304	106
Net Income	$28,396	$27,403	$ 993
Earnings Per Share of Common Stock			
Basic	$1.86	$1.84	$ 0.02
Diluted	$1.85	$1.83	$ 0.02

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(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Six months ended June 30, 2015 Reported Results	$45,707	$27,403	$ 1.83
Adjusting for Unusual Items:			
Weather impact, primarily in the first quarter	(6,596)	(3,954)	(0.26)
Net gain from settlement agreement associated with customer billing system	(1,370)	(821)	(0.05)
	(7,966)	(4,775)	(0.31)
Increased (Decreased) Gross Margins:			
Service expansions (See Major Projects and Initiatives table)	3,939	2,361	0.16
GRIP	2,148	1,288	0.09
Lower retail propane margins	(1,737)	(1,041)	(0.07)
Natural gas growth (excluding service expansions)	1,579	947	0.06
Natural gas marketing	905	543	0.04
Implementation of Delaware division interim rates	878	526	0.03
Eight Flags	551	330	0.02
	8,263	4,954	0.33
Decreased (Increased) Other Operating Expenses:			
Higher payroll and benefit costs	(1,339)	(803)	(0.05)
Higher depreciation, asset removal and property tax costs due to recent capital investments	(1,253)	(751)	(0.05)
Lower bad debt, sales and advertising	482	289	0.02
Decreased incentive compensation	466	279	0.02
	(1,644)	(986)	(0.06)
Net contribution from Aspire Energy, including impact of shares issued	2,978	1,892	0.09
Interest Charges	(341)	(204)	(0.01)
Net Other Changes	(191)	112	(0.02)
Six months ended June 30, 2016 Reported Results	$46,806	$28,396	$ 1.85

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Summary of Key Factors
Major Projects and Initiatives

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

	Gross Margin for the Period							
	Three Months Ended June 30,		Six Months Ended June 30,		Total 2015	Estimate for		
	2016	2015	2016	2015	Margin	2016	2017	2018
Completed major projects and initiatives effected since 2014	$10,487	$5,642	$22,256	$9,791	$25,270	$47,769	$53,991	$54,646
Major projects and initiatives underway [1]	—	—	—	—	—	—	2,250	4,500
	$10,487	$5,642	$22,256	$9,791	$25,270	$47,769	$56,241	$59,146

[1] This represents gross margin for the 2017 System Reliability Project.

Completed Major Projects and Initiatives

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

	Gross Margin for the Period									
	Three Months Ended June 30,			Six Months Ended June 30,			Total 2015	Estimate for		
	2016	2015	Variance	2016	2015	Variance	Margin	2016	2017	2018
Acquisition:										
Aspire Energy	$2,331	$1,624	$707	$6,573	$1,624	$4,949	$6,324	$12,824	$14,198	$15,415
Natural Gas Transmission Expansions and Contracts:										
Short-term contracts										
New Castle County, Delaware	$616	$523	$93	$1,375	$1,491	$(116)	$2,682	$2,707	$1,885	$677
Kent County, Delaware [1]	2,032	398	1,634	3,815	398	3,417	$2,270	7,965	1,534	—
Total short-term contracts	$2,648	$921	$1,727	$5,190	$1,889	$3,301	$4,952	$10,672	$3,419	$677
Long-term contracts										
Kent County, Delaware	$455	$463	$(8)	$911	$926	$(15)	$1,844	$1,815	$7,629	$7,605
Polk County, Florida	407	134	273	814	161	653	908	1,627	1,627	1,627
Total long-term contracts	$862	$597	$265	$1,725	$1,087	$638	$2,752	$3,442	$9,256	$9,232
Total Expansions & Contracts	$3,510	$1,518	$1,992	$6,915	$2,976	$3,939	$7,704	$14,114	$12,675	$9,909
Florida GRIP	$2,809	$1,769	$1,040	$5,396	$3,248	$2,148	$7,508	$11,405	$13,756	$15,960
Florida Electric Rate Case	$731	$731	$—	$1,943	$1,943	$—	$3,734	$3,562	$3,562	$3,562
Delaware Division Rate Case [2]	$555	$—	$555	$878	$—	$878	$—	$2,164	$2,500	$2,500
Eight Flags CHP Plant [3]	$551	$—	$551	$551	$—	$551	$—	$3,700	$7,300	$7,300
Total Completed Major Projects and Initiatives	$10,487	$5,642	$4,845	$22,256	$9,791	$12,465	$25,270	$47,769	$53,991	$54,646

[1] In April 2015, Eastern Shore commenced interruptible service to an electric power generator in Kent County, Delaware. The interruptible service concluded in December 2015 and was replaced by a short-term OPT ≤ 90 Service. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year contract for OPT ≤ 90 Service in the first

quarter of 2017.

(2) In December 2015, our Delaware division submitted a rate case filing with the Delaware PSC. A decision on this application is expected during the first quarter of 2017. Pending the decision, our Delaware division implemented interim rates effective February 19, 2016. These rates are subject to refund. We cannot predict the revenue requirement the Delaware PSC will ultimately authorize or forecast timing of the decision.

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(3) This amount includes gross margin of $432,000 for the three and six months ended June 30, 2016, attributed to natural gas distribution and transportation services provided by our affiliates.

Aspire Energy

On April 1, 2015, we completed the merger of Gatherco with and into Aspire Energy, a then newly-formed, wholly-owned subsidiary of Chesapeake Utilities. Aspire Energy is an unregulated natural gas infrastructure company with approximately 2,500 miles of pipeline systems in 40 counties throughout Ohio. The majority of Aspire Energy's margin is derived from long-term sales agreements with Columbia Gas and Consumers Gas Cooperative, which together serve more than 20,000 end-use customers. Aspire Energy sources gas primarily from 300 conventional producers in Ohio. Aspire Energy also provides gathering and processing services necessary to maintain quality and reliability to its wholesale markets.

Aspire Energy generated $707,000 and $4.9 million in additional gross margin for the three and six months ended June 30, 2016, and incurred $363,000 and $2.0 million in other operating expenses for the same periods, respectively. As projected, this merger was accretive to our earnings per share in the first full year of operations, generating $0.03 in additional earnings per share.

Service Expansions

On January 16, 2015, the Florida PSC approved a firm transportation agreement between Peninsula Pipeline and our Florida natural gas distribution division. Under this agreement, Peninsula Pipeline provides natural gas transmission service to support our expansion of natural gas distribution service in Polk County, Florida. Peninsula Pipeline began the initial phase of its service to Chesapeake Utilities' Florida natural gas distribution division in March 2015. This new service generated $273,000 and $653,000 of additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015. When all phases of this service are complete, this expansion will generate an estimated annual gross margin of $1.6 million.

In April 2015, Eastern Shore commenced interruptible service to an electric power generator in Kent County, Delaware. The interruptible service concluded in December 2015 and was replaced by a short-term OPT ≤ 90 Service, which generated additional gross margin of $1.6 million and $3.4 million during the three and six months ended June 30, 2016, respectively. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year contract for OPT ≤ 90 Service in the first quarter of 2017.

On October 13, 2015, Eastern Shore submitted an application to the FERC to make certain measurement and related improvements at its TETLP interconnect facilities, which will enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. In December 2015, the FERC authorized Eastern Shore to proceed with this project, which was completed and placed in service in March 2016. Approximately, 80 percent of the increased capacity has been subscribed on a short-term firm service basis. This service generated an additional gross margin of $108,000 and $128,000 for the three and six months ended June 30, 2016, respectively, and will generate approximately $1.4 million in additional gross margin through 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 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 $91.5 million to replace 191 miles of qualifying distribution mains, including $14.7 million during the first six months of 2016. We expect to invest an additional $6.4 million in this program during the remainder of 2016. The increased investment in GRIP generated additional gross margin of $1.0 million and $2.1 million for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015.

Eight Flags

In June 2016, Eight Flags, one of our unregulated energy subsidiaries, substantially completed construction of a CHP plant in Nassau County, Florida. This CHP plant, which consists of a natural-gas-fired turbine and associated electric generator, can produce approximately 20 megawatts of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of unfired steam. Beginning June 13, 2016, Eight Flags began selling power generated from the CHP plant to FPU, our wholly-owned subsidiary, for distribution to its retail electric customers pursuant to a 20-year power purchase agreement. On July 1, 2016, it also started selling steam to an industrial customer pursuant to a separate 20-year contract. FPU will be transporting natural gas through its distribution system to Eight Flags' CHP plant, which will be used to power the CHP plant. Eight Flags and other affiliates of Chesapeake Utilities generated $551,000 in additional gross margin as a result of these new services, including natural gas and distribution services, for the three and six months ended June 30, 2016. On a consolidated basis, this project is expected to generate approximately $7.3 million in annual gross margin, which could fluctuate based upon various factors, including, but not limited to, the quantity of steam delivered and the CHP plant's hours of operations.

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Major Projects and Initiatives Underway

White Oak Mainline Expansion Project: In December 2014, Eastern Shore entered into a precedent agreement with an electric power generator in Kent County, Delaware, to provide a 20-year natural gas transmission service for 45,000 Dts/d for the customer's facility, upon the satisfaction of certain conditions. This new service will be provided as a long-term OPT ≤ 90 Service and is expected to generate at least $5.8 million in annual gross margin. In November 2014, Eastern Shore requested authorization by the FERC to construct 5.4 miles of 16-inch pipeline looping and 3,550 horsepower of new compression in Delaware to provide this service. As previously discussed, during the three and six months ended June 30, 2016, we generated $1.6 million and $3.4 million, respectively, in additional gross margin by providing interruptible service and short-term OPT ≤ 90 Service to this customer. The estimated annual gross margin contribution from this project, once it is placed in service, is approximately $5.8 million. On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed White Oak Mainline Project.

System Reliability Project: On May 22, 2015, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore’s customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days. Since the project is intended to improve system reliability, Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project and an order granting the requested authorization. This project will be included in Eastern Shore's upcoming 2017 rate case filing. The estimated annual gross margin associated with this project, assuming recovery in the 2017 rate case, is approximately $4.5 million. On July 21, 2016, the FERC issued a certificate of public convenience and necessity authorizing Eastern Shore to construct and operate the proposed System Reliability Project.

2017 Expansion Project: On May 12, 2016, Eastern Shore submitted a request to the FERC to initiate the FERC's pre-filing procedures for its proposed 2017 expansion project. The 2017 expansion project consists of approximately 33 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing facilities; installation of an additional 3,550 horsepower compressor unit at the existing Daleville compressor station in Chester County, Pennsylvania; approximately 17 miles of new mainline extension; and the addition of two pressure control stations in Sussex County, Delaware. The proposed 2017 expansion project would provide up to 86,437 Dts/d of additional firm natural gas transportation capacity to meet anticipated market demand. Eastern Shore is currently negotiating precedent agreements with customers who have expressed an interest in this service.

Other factors influencing gross margin

Weather and Consumption

Weather was not a significant factor in the second quarter. Temperatures on the Delmarva Peninsula and in Florida during the first quarter of 2016 were significantly warmer than the first quarter of 2015, which negatively affected the Company's year-to-date results in 2016. Lower customer consumption, directly attributable to warmer than normal temperatures during the six months ended June 30, 2016, reduced gross margin by $6.6 million compared to the same period in 2015. The following tables summarize the HDD and CDD information for the three and six months ended June 30, 2016 and 2015 resulting from weather fluctuations in those periods.

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HDD and CDD Information

	Three Months Ended June 30, 2016	2015	Variance	Six Months Ended June 30, 2016	2015	Variance
Delmarva						
Actual HDD	485	386	99	2,579	3,208	(629)
10-Year Average HDD ("Delmarva Normal")	452	443	9	2,854	2,843	11
Variance from Delmarva Normal	33	(57)		(275)	365	
Florida						
Actual HDD	49	—	49	646	501	145
10-Year Average HDD ("Florida Normal")	19	24	(5)	553	557	(4)
Variance from Florida Normal	30	(24)		93	(56)	
Ohio						
Actual HDD	830	632	198	3,683	4,413	(730)
10-Year Average HDD ("Ohio Normal")	666	669	(3)	3,842	3,778	64
Variance from Ohio Normal	164	(37)		(159)	635	
Florida						
Actual CDD	1,028	1,114	(86)	1,214	1,236	(22)
10-Year Average CDD ("Florida CDD Normal")	948	909	39	1,025	982	43
Variance from Florida CDD Normal	80	205		189	254	

Propane prices

For the quarter ended June 30, 2016, retail propane margins per gallon generated additional gross margin of $185,000, compared to the same period last year. For the six months ended June 30, 2016, compared to the same period in 2015, margins per retail gallon returned to more normal levels, which resulted in a year-to-date decline in gross margin of $1.9 million, driven principally by lower propane prices and local market conditions. The level of retail margins per gallon generated during 2015 were not expected to be sustained over the long term; accordingly, the Company has assumed more normal levels of margins in its long-term financial plans and forecasts.

In Florida, higher retail propane margins per gallon, resulting from local market conditions, generated $6,000 and $131,000 of additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015.

These market conditions, which are influenced by competition with other propane suppliers as well as the availability and price of alternative energy sources, may fluctuate based on changes in demand, supply and other energy commodity prices.

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $509,000 and $854,000 in additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015, due to an increase in residential, commercial and industrial customers served. The average number of residential customers on the Delmarva Peninsula during the three and six months ended June 30, 2016, increased by 3.8 percent and 3.2 percent, respectively, compared to the same periods in 2015. The natural gas distribution operations in Florida generated $406,000 and $652,000 in additional gross margin for the three and six months ended June 30, 2016, respectively, compared to the same periods in 2015, due primarily to an increase in commercial and industrial customers in Florida.

Delaware division rate case

On December 21, 2015, our Delaware division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. We proposed an increase of approximately $4.7 million, or nearly ten percent, in our revenue requirement based on the test period ending March 31, 2016. See Note 4, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for additional details. We expect a decision on the application during the first quarter of 2017. Pending the decision, our Delaware division increased rates on an interim basis based on the $2.5 million annualized interim rates approved by the Delaware PSC, effective February 19, 2016. We generated additional gross margin of approximately $555,000 ($332,000 net of tax) and $878,000 ($526,000 net of tax) for the three and six months ended June 30, 2016, respectively, from the implementation of interim rates. In addition, the Company's Delaware division requested and received approval on July 26, 2016 from the Delaware PSC to implement revised interim rates of $4.7 million annualized for usage on and after August 1, 2016. These rates, are subject to refund. Although a final decision is expected during the first quarter of 2017, we cannot predict the revenue requirement the Delaware PSC will ultimately authorize or forecast the timing of a final decision.

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Regulated Energy Segment

For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015

	Three Months Ended June 30,		Increase
	2016	2015	(decrease)
(in thousands)			
Revenue	$67,395	$62,060	$ 5,335
Cost of sales	21,635	21,124	511
Gross margin	45,760	40,936	4,824
Operations & maintenance	21,301	18,484	2,817
Depreciation & amortization	6,267	6,080	187
Other taxes	2,966	2,767	199
Other operating expenses	30,534	27,331	3,203
Operating income	$15,226	$13,605	$ 1,621

Operating income for the Regulated Energy segment for the quarter ended June 30, 2016 was $15.2 million, an increase of $1.6 million, or 11.9 percent, compared to the same quarter in 2015. The increased operating income was primarily due to an increase in gross margin of $4.8 million, partially offset by an increase in operating expenses of $3.2 million.

Gross Margin

Items contributing to the quarter-over-quarter increase of $4.8 million, or 11.8 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended June 30, 2015	$40,936
Factors contributing to the gross margin increase for the three months ended June 30, 2016:	
Service expansions	1,992
Additional revenue from GRIP in Florida	1,040
Natural gas growth (excluding service expansions)	820
Implementation of Delaware division interim rates	555
Eight Flags	432
Other	(15)
Gross margin for the three months ended June 30, 2016	$45,760

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

Service Expansions

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

- $1.6 million from the short-term OPT ≤ 90 Service that commenced in December 2015 to an electric power generator in Kent County, Delaware following the conclusion of an interruptible service Eastern Shore had provided this customer. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year OPT ≤ 90 Service in the first quarter of 2017.
- $273,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2015 and 2016 by our Florida natural gas distribution operations generated $1.0 million in additional gross margin

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Natural Gas Growth (excluding service expansions)

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

- $509,000 from a 3.8 percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers; and
- $406,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.

Implementation of Delaware Division Interim Rates

Delaware division generated additional gross margin of $555,000 from the implementation of interim rates as a result of its rate case filing. See Note 4, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for additional details.

Eight Flags

We generated additional gross margin of $432,000 during the quarter, from new natural gas transmission and distribution services provided to or by Eight Flags' CHP plant.

Other Operating Expenses

Other operating expenses increased by $3.2 million. The significant components of the increase in other operating expenses included:

- The absence of a $1.5 million gain from a customer billing system settlement, recorded in 2015, which was partially offset by an associated gain of $130,000 during the second quarter of 2016, representing an additional current portion of the settlement recovery;
- $724,000 in higher payroll and benefits costs for additional personnel to support growth;
- $722,000 in higher service contractor and consulting costs; and
- $385,000 in higher depreciation, asset removal and property tax costs associated with recent capital investments.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015

	Six Months Ended June 30,		Increase
	2016	2015	(decrease)
(in thousands)			
Revenue	$156,611	$171,642	$(15,031)
Cost of sales	56,540	78,253	(21,713)
Gross margin	100,071	93,389	6,682
Operations & maintenance	41,761	39,768	1,993
Depreciation & amortization	12,563	11,979	584
Other taxes	6,202	5,854	348
Other operating expenses	60,526	57,601	2,925
Operating income	$39,545	$35,788	$3,757

Operating income for the Regulated Energy segment for the six months ended June 30, 2016 was $39.5 million, an increase of $3.8 million, or, 10.5 percent, compared to the same period in 2015. The increased operating income was due primarily to an increase in gross margin of $6.7 million partially offset by a $2.9 million increase in operating expenses.

Gross Margin

Items contributing to the period-over-period increase of $6.7 million, or 7.2 percent, in gross margin are listed in the following table:

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(in thousands)	
Gross margin for the six months ended June 30, 2015	$93,389
Factors contributing to the gross margin increase for the six months ended June 30, 2016:	
Service expansions	3,939
Decreased customer consumption - weather and other	(2,456)
Additional revenue from GRIP in Florida	2,148
Natural Gas Growth (excluding service expansions)	1,579
Implementation of Delaware division interim rates	878
Eight Flags	432
Other	162
Gross margin for the six months ended June 30, 2016	$100,071

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

Service Expansions

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

- $3.4 million from the short-term OPT ≤ 90 Service that commenced in December 2015 to an electric power generator in Kent County, Delaware following the conclusion of an interruptible service Eastern Shore had provided this customer. The short-term OPT ≤ 90 Service is expected to be replaced by a 20-year OPT ≤ 90 Service in the first quarter of 2017; and
- $653,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.

Decreased Customer Consumption—Weather and Other

In the first six months of 2016, customer consumption of natural gas and electricity decreased primarily due to significantly warmer weather on the Delmarva Peninsula, which reduced gross margin by approximately $2.5 million.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2015 and 2016 by our Florida natural gas distribution operations generated $2.1 million in additional gross margin.

Natural Gas Growth (excluding service expansions)

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

- $854,000 from a 3.2 percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers; and
- $652,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers.

Implementation of Delaware Division Interim Rates

Delaware division generated additional gross margin of $878,000 from the implementation of interim rates as a result of its rate case filing. See Note 4, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for additional details.

Eight Flags

We generated additional gross margin of $432,000 from new natural gas transmission and distribution services provided to or by Eight Flags' CHP plant, commencing in June of 2016.

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Other Operating Expenses

Other operating expenses increased by $2.9 million. The significant components of the increase in other operating expenses included:

- The absence of a $1.5 million gain from a customer billing system settlement, recorded in 2015, which was partially offset by an associated gain of $130,000 during the second quarter of 2016, representing an additional current portion of the settlement recovery;
- $1.0 million in higher depreciation, asset removal and property tax costs associated with recent capital investments; and
- $565,000 in higher payroll and benefits costs for additional personnel to support growth.

Unregulated Energy Segment

For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015

	Three Months Ended June 30, 2016	2015	Increase (decrease)
(in thousands)			
Revenue	$36,803	$32,559	$ 4,244
Cost of sales	24,726	22,156	2,570
Gross margin	12,077	10,403	1,674
Operations & maintenance	9,771	9,130	641
Depreciation & amortization	1,490	1,439	51
Other taxes	404	374	30
Other operating expenses	11,665	10,943	722
Operating Income	$412	$(540)	$ 952

Operating income for the Unregulated Energy segment increased by $952,000 to $412,000 in the second quarter of 2016, compared to an operating loss of $540,000 in the same quarter of 2015. The results for the second quarter include an increase in gross margin of $708,000 and other operating expenses of $363,000 from Aspire Energy. Excluding these impacts from Aspire Energy, gross margin increased by $966,000, offset by a $359,000 increase in other operating expenses.

Gross Margin

Items contributing to the quarter-over-quarter increase of $1.7 million, or 16.1 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended June 30, 2015	$10,403
Factors contributing to the gross margin increase for the three months ended June 30, 2016:	
Aspire Energy	708
Natural gas marketing	464
Increased customer consumption - weather and other	370
Other	132
Gross margin for the three months ended June 30, 2016	$12,077

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

Aspire Energy

Aspire Energy generated $708,000 in additional gross margin for the quarter ended June 30, 2016 as a result of additional margins generated by pricing amendments to long-term sales agreements, the elimination of gas retainage volume credits associated with shrinkage for gas processing activities, and the optimization of gathering system receipts and deliveries through improved management and monitoring of system volumes and imbalance positions.

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Natural Gas Marketing

PESCO generated $464,000 in additional gross margin due primarily to customer growth, which includes a new SCO supplier agreement with Columbia Gas, and the positive impact from favorable supply management and hedging activities, which generated additional gross margin as a result of a decrease in inventory costs. The increase in gross margin as a result of favorable supply management and hedging activities is not predictable and, therefore, is not included in our long-term financial plans or forecasts.

Increased Customer Consumption - Weather and Other

Gross margin increased by $370,000 due to increased deliveries of propane as a result of weather and the timing of bulk deliveries.

Other Operating Expenses

The increase in other operating expenses was due primarily to $481,000 in higher payroll and benefits costs for additional personnel to support growth.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015

(in thousands)	Six Months Ended June 30, 2016	2015	Increase (decrease)
Revenue	$94,319	93,555	$764
Cost of sales	59,141	57,833	1,308
Gross margin	35,178	35,722	(544)
Operations & maintenance	19,162	17,687	1,475
Depreciation & amortization	2,672	2,490	182
Other taxes	997	856	141
Other operating expenses	22,831	21,033	1,798
Operating Income	$12,347	$14,689	$(2,342)

Operating income for the Unregulated Energy segment decreased by $2.4 million, to $12.3 million, in the first six months of 2016, compared to $14.7 million in the same period of 2015. The results for the first six months include an increase in gross margin of $4.9 million and other operating expenses of $2.0 million from Aspire Energy. Excluding these impacts from Aspire Energy, gross margin and other operating expenses decreased by $5.5 million, and $174,000, respectively.

Gross Margin

Items contributing to the period-over-period decrease of $544,000 or 1.5 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the six months ended June 30, 2015	$35,722
Factors contributing to the gross margin decrease for the six months ended June 30, 2016:	
Aspire Energy	4,949
Decreased customer consumption - weather and other	(3,867)
Decrease in retail propane margins	(1,737)
Natural gas marketing	905
Propane wholesale sales	(452)
Other	(342)
Gross margin for the six months ended June 30, 2016	$35,178

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

Aspire Energy
Aspire Energy generated $6.6 million in gross margin compared to $1.6 million in the same period of 2015. Results for the first six months of 2015 reflect only three months of margin for Aspire Energy, which became a wholly-owned subsidiary of Chesapeake Utilities on April 1, 2015. In addition, Aspire Energy generated additional margins as a result of pricing amendments to long-term gas sales agreements, the elimination of gas retainage volume credits associated with shrinkage for gas processing activities, and the optimization of gathering system receipts and deliveries through improved management and monitoring of system volumes and imbalance positions.

Decreased Customer Consumption - Weather and Other
Gross margin decreased by $3.9 million due to lower customer consumption of propane. The decrease was driven mainly by weather as a result of warmer temperatures on the Delmarva Peninsula during the first six months of 2016 compared to significantly colder temperatures during the first six months of 2015.
Decrease in Retail Propane Margins
Lower retail propane margins for our Delmarva propane distribution operation decreased gross margin by $1.9 million, as margins per retail gallon returned to more normal levels. The decline in margin was driven principally by lower propane prices and local market conditions. The level of retail margins per gallon generated during 2015 were not expected to be sustained over the long term; accordingly, we have assumed more normal levels of margins in our long-term financial plans and forecasts.
This decrease was partially offset by $131,000 in higher retail propane margins per gallon for our Florida propane distribution operation as a result of local market conditions.

Natural Gas Marketing
PESCO generated $905,000 in additional gross margin due to customer growth, which includes its SCO supplier agreement with Columbia Gas, and the positive impact from favorable supply management and hedging activities, which generated additional gross margin as a result of a decrease in inventory costs. The increase in gross margin as a result of favorable supply management and hedging activities is not predictable and, therefore, is not included in our long-term financial plans or forecasts.

Propane wholesale sales
Gross margin decreased by $452,000 as a result of lower propane wholesale sales associated with the sales agreement with an affiliate of ESG, that has a propane supply agreement with Sandpiper Energy. The lower sales are expected as more customers in Ocean City, Maryland and surrounding areas are converted from propane to natural gas. Lower sales due to significantly warmer weather in the first six months of 2016 compared to the same period in 2015, also contributed to this decrease.

Other Operating Expenses
The increase in other operating expenses was due primarily to $2.0 million in other operating expenses incurred by Aspire Energy, given the additional quarter's results included in 2016, compared to only three months of results in the six months ended June 30, 2015. This increase in expenses was partially offset by $161,000 in lower accruals for incentive compensation as a result of the lower financial results, due to the impact of significantly warmer weather on financial results.

Interest Charges
For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015

Interest charges for the three months ended June 30, 2016 increased slightly by approximately $139,000, compared to the same quarter in 2015.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015
Interest charges for the six months ended June 30, 2016 increased slightly by approximately $341,000, compared to the same period in 2015.

Income Taxes

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For the quarter ended June 30, 2016 compared to the quarter ended June 30, 2015
Income tax expense was $5.1 million in the second quarter of 2016, compared to $4.2 million in the same quarter in 2015. The increase in income tax expense was due primarily to higher taxable income. Our effective income tax rate was 38.8 percent and 40.1 percent, for the second quarter of 2016 and 2015, respectively.

For the six months ended June 30, 2016 compared to the six months ended June 30, 2015
Income tax expense was $18.4 million in the six months ended June 30, 2016, compared to $18.3 million in the same period in 2015. The decrease in income tax expense was due primarily to lower taxable income. Our effective income tax rate was 39.3 percent and 40.0 percent, for the first six months of 2016 and 2015, respectively.

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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 target.

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

Our capital expenditures for the six months ended June 30, 2016 were approximately $70.3 million. We currently project capital expenditures of $179.3 million in 2016. Our current forecast by segment and business line is shown below:

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

The 2016 forecast includes expenditures for the following projects: Eight Flags' CHP plant; anticipated new facilities to serve an electric power generator in Kent County, Delaware under the OPT ≤ 90 Service; Eastern Shore's system reliability project; additional expansions of our natural gas distribution and transmission systems; continued natural gas infrastructure improvement activities; expenditures for continued replacement under the Florida GRIP; replacement of several facilities and systems; and other strategic initiatives and investments. In addition, we included $30.0 million in the 2016 forecast for projects that are in the early development stage.

Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts. The timing of capital expenditures can vary based on securing environmental approvals and other permits. The regulatory application and approval process has lengthened, and we expect this trend to continue.

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Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following table presents our capitalization, excluding and including short-term borrowings, as of June 30, 2016 and December 31, 2015:

(in thousands)	June 30, 2016		December 31, 2015	
Long-term debt, net of current maturities	$143,865	27 %	$149,006	29 %
Stockholders’ equity	379,554	73 %	358,138	71 %
Total capitalization, excluding short-term debt	$523,419	100%	$507,144	100%

(in thousands)	June 30, 2016		December 31, 2015	
Short-term debt	$180,042	25 %	$173,397	25 %
Long-term debt, including current maturities	155,940	22 %	158,157	23 %
Stockholders’ equity	379,554	53 %	358,138	52 %
Total capitalization, including short-term debt	$715,536	100%	$689,692	100%

Included in the long-term debt balances at June 30, 2016 and December 31, 2015, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($2.8 million and $3.5 million, respectively, net of current maturities, and $4.2 million and $4.8 million, respectively, including current maturities). Sandpiper entered into this six-year agreement at the closing of the ESG acquisition in May 2013. 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 52 percent and 54 percent during the past three years. Our equity as a percent of total capitalization declined in 2015 as we financed several large revenue generating capital projects with short-term borrowings. As we continue to construct these projects in 2016, the ratio of equity to total capitalization, including short-term borrowings, will further decline temporarily.

As described below under “Short-term Borrowings,” we entered into a new Revolver with the Lenders on October 8, 2015, which increased our borrowing capacity by $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we also entered into a long-term private placement Shelf Agreement with Prudential that is further described below under the heading “Shelf Agreement.”

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

Short-term Borrowings

Our outstanding short-term borrowings at June 30, 2016 and December 31, 2015 were $180.0 million and $173.4 million, respectively. The weighted average interest rates for our short-term borrowings were 1.39 percent and 1.08 percent, for the six months ended June 30, 2016 and 2015, 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 June 30, 2016, we had four unsecured bank credit facilities with three financial institutions totaling $170.0 million in total available credit. In addition, since October 2015, we have $150.0 million of additional short-term debt capacity available under a Revolver with five participating Lenders. The terms of the Revolver are described in further detail below. We also had access to two credit facilities, which totaled $40.0 million; however, these credit facilities expired on October 31, 2015 and were not renewed given the addition of the new Revolver. None of the unsecured bank lines of credit requires compensating balances. We are currently authorized by our Board of Directors to borrow up to $275.0 million of short-term borrowing.

The $150.0 million Revolver has a five-year term and is subject to the terms and conditions set forth in the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures. Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization,

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both as defined by the Credit Agreement, or (ii) the base rate plus 0.25% or less. Interest is payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We may extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each Lender. At June 30, 2016 and December 31, 2015, we had borrowed $40.0 million and $35.0 million, respectively, under the Revolver.

Shelf Agreement

On October 8, 2015, we entered into a committed Shelf Agreement with Prudential and other purchasers that may become a party to the Shelf Agreement. Under the terms of the Shelf Agreement, we may request that Prudential purchase, over the next three years, up to $150.0 million of our Shelf Notes at a fixed interest rate and with a maturity date not to exceed twenty years from the date of issuance. Prudential and its affiliates are under no obligation to purchase any of the Shelf Notes. The interest rate and terms of payment of any series of Shelf Notes will be determined at the time of purchase. We currently anticipate that the proceeds from the sale of any series of Shelf Notes will be used for general corporate purposes, including refinancing of short-term borrowings and/or repayment of outstanding indebtedness and financing of capital expenditures on future projects; however, actual use of such proceeds will be determined at the time of a purchase, and each request for purchase with respect to a series of Shelf Notes will specify the use of the proceeds.

On May 13, 2016, we formally requested that Prudential purchase $70.0 million of 3.25 percent Shelf Notes under the Shelf Agreement. On May 20, 2016, Prudential formally accepted and confirmed our request. The closing of the sale and issuance of our Shelf Notes is expected to occur on or before April 28, 2017.

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

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
	2016	2015
(in thousands)		
Net cash provided by (used in):		
Operating activities	$74,155	$80,402
Investing activities	(70,133)	(78,304)
Financing activities	(3,611)	(4,568)
Net increase (decrease) in cash and cash equivalents	411	(2,470)
Cash and cash equivalents—beginning of period	2,855	4,574
Cash and cash equivalents—end of period	$3,266	$2,104

Cash Flows Provided By Operating Activities

Changes in our cash flows from operating activities are attributable primarily to changes in net income, non-cash adjustments for depreciation, deferred income taxes and working capital. Changes in working capital are determined by a variety of factors, including weather, the prices of natural gas, electricity and propane, the timing of customer collections, payments for purchases of natural gas, electricity and propane, and deferred fuel cost recoveries.

During the six months ended June 30, 2016 and 2015, net cash provided by operating activities was $74.2 million and $80.4 million, respectively, resulting in a decrease in cash flows of $6.2 million. Significant operating activities generating the cash flows change were as follows:

- Net income, adjusted for reconciling activities, increased cash flows by $11.2 million, due primarily to an increase in deferred income taxes as a result of the availability and utilization of bonus depreciation in the first six months of 2016, which resulted in a higher book-to-tax timing difference and higher non-cash adjustments for depreciation and amortization.

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- The changes in net regulatory assets and liabilities decreased cash flows by $12.2 million, due primarily to the change in fuel costs collected through the various fuel cost recovery mechanisms.
- The changes in net accounts receivable and payable decreased cash flows by $5.6 million, due primarily to the timing of the receipt of customer payments as well as the timing of payments to vendors.
- Changes in customer deposits and refunds increased cash flows by $4.1 million.
- Net cash flows from changes in propane, natural gas and materials inventories decreased by approximately $3.7 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $70.1 million and $78.3 million during the six months ended June 30, 2016 and 2015, respectively, resulting in an increase in cash flows of $8.2 million. The decrease in net cash used in investing activities was due primarily to a decrease in cash used for acquisitions. The cash expended in 2015 was associated with the Gatherco merger.

Cash Flows Used in Financing Activities

Net cash used in financing activities totaled $3.6 million in the first six months of 2016, compared to $4.6 million in the same period in 2015, resulting in an increase in cash flows of $1.0 million.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily Xeron and PESCO, which provide for the payment of propane and natural gas purchases in the event that the subsidiary defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at June 30, 2016 was $53.6 million, with the guarantees expiring on various dates through June 2017.

We have issued letters of credit totaling $8.1 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 March 2017. There have been no draws on these letters of credit as of June 30, 2016. 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 Item 1, Financial Statements, Note 6, Other Commitments and Contingencies in the Condensed Consolidated Financial Statements.

Contractual Obligations

There has been no material change in the contractual obligations presented in our 2015 Annual Report on Form 10-K, except for commodity purchase obligations and forward contracts entered into in the ordinary course of our business. The following table summarizes commodity and forward contract obligations at June 30, 2016.

	Payments Due by Period				
	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
(in thousands)					
Purchase obligations - Commodity [1]	$46,383	$ 5,903	$ —	$ —	$52,286
Forward purchase contracts - Propane [2]	227	—	—	—	227
Total	$46,610	$ 5,903	$ —	$ —	$52,513

(1) In addition to the obligations noted above, the natural gas, electric and propane distribution operations 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.

(2) We have also entered into forward sale contracts. See Item 3, Quantitative and Qualitative Disclosures About Market Risk for further information.

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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 June 30, 2016, we were involved in regulatory matters in each of the jurisdictions in which we operate. Our significant regulatory matters are fully described in Note 4, Rates and Other Regulatory Activities, to the unaudited 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 unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes and secured debt. All of our long-term debt, excluding a capital lease obligation, is fixed-rate debt and was not entered into for trading purposes. The carrying value of our long-term debt, including current maturities, but excluding a capital lease obligation, was $151.8 million at June 30, 2016, as compared to a fair value of $174.3 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

Our propane distribution business is exposed to market risk as a result of our propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 6.8 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers’ peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline. To mitigate the impact of price fluctuations, we have adopted a Risk Management Policy that allows the propane distribution operation to enter into fair value hedges or other economic hedges of our inventory.

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

The forward and futures contracts are entered into for trading and wholesale marketing purposes. The propane wholesale marketing business is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets and the credit risk of counter-parties, 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. Quantitative information on forward and future contracts at June 30, 2016 is presented in the following table:

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At June 30, 2016	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts - Propane			
Purchase	421,000	$ 0.5375	$ 0.5388

At June 30, 2016	Quantity in Barrels	Estimated Market Prices	Weighted Average Contract Prices
Futures Contracts - Crude Oil			
Purchase	20,000	$ 48.33	$ 47.90

Estimated market prices and weighted average contract prices are in dollars per gallon and barrel. All contracts expire by the end of the third quarter of 2016.

Our natural gas distribution, electric distribution and natural gas marketing operations have entered into agreements with various suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered “normal purchases and sales” and are accounted for on an accrual basis.

At June 30, 2016 and December 31, 2015, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	June 30, 2016	December 31, 2015
Mark-to-market energy assets, including call options, swap agreements and futures	$ 405	$ 153
Mark-to-market energy liabilities, including swap agreements and futures	$ 256	$ 433

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of the Company, 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 June 30, 2016. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2016.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2016, 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.

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PART II—OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 6, Other Commitments and Contingencies, of the unaudited 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, 2015, 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 the Company, 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 the Company. 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)
April 1, 2016 through April 30, 2016 (1)	364	$ 60.00	—	—
May 1, 2016 through May 31, 2016	—	$ —	—	—
June 1, 2016 through June 30, 2016	—	$ —	—	—
Total	364	$ 60.00	—	—

(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, 2015. During the quarter ended June 30, 2016, 364 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

10.1	Executive Employment Agreement dated May 10, 2016, between Chesapeake Utilities Corporation and James F. Moriarty, is filed herewith.
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.

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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: August 4, 2016