CHESAPEAKE UTILITIES CORP
Form 10-Q
May 06, 2015
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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: March 31, 2015

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	¨	Accelerated filer	x
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 — 15,225,683 shares outstanding as of April 30, 2015.

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GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification
ASU: Accounting Standards Update
Aspire Energy of Ohio: Aspire Energy of Ohio, LLC, a newly formed, wholly-owned subsidiary of Chesapeake into which Gatherco, Inc. merged.
BravePoint: BravePoint, Inc., our advanced information services subsidiary, headquartered in Norcross, Georgia, which was sold on October 1, 2014
CDD: Cooling degree-days, 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: 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
Chesapeake Postretirement Plan: An unfunded postretirement health care and life insurance plan sponsored by Chesapeake
Chesapeake SERP: An unfunded supplemental executive retirement pension plan sponsored by Chesapeake
CHP: A combined heat and power plant being constructed by Eight Flags in Nassau County, Florida
Company: Chesapeake Utilities Corporation, its divisions and its subsidiaries, as appropriate in the context of the disclosure
CP: Certificate of Public Convenience and Necessity
Deferred Compensation Plan: A non-qualified, deferred compensation arrangement under which certain of our executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors’ retainers and fees
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
EGWIC: Eastern Gas & Water Investment Company, LLC, an affiliate of Eastern Shore Gas Company
Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake Onsight Services, LLC
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 Federal 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
FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake

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FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake
GAAP: Accounting principles generally accepted in the United States of America
Gatherco: Gatherco, Inc.
GRIP: Gas Reliability Infrastructure Program, which is a surcharge to natural gas customers designed to recover capital and other program-related costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services in Florida
Gulf Power: Gulf Power Company
Gulfstream: Gulfstream Natural Gas System, LLC
HDD: Heating degree-days, 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
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
Note Agreement: Note Purchase Agreement entered into by Chesapeake with Note Holders on September 5, 2013
Note Holders: PAR U Hartford Life & Annuity Comfort Trust, The Prudential Insurance Company of America, The Gibraltar Life Insurance Co., Ltd., The Penn Mutual Life Insurance Company, Thrivent Financial for Lutherans, United of Omaha Life Insurance Company, and Companion Life Insurance Company, which are collectively the lenders that entered into the Note Agreement with Chesapeake on September 5, 2013
Notes: Series A and B unsecured Senior Notes that have been entered into with the Note Holders
OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a new tariff associated with Eastern Shore's firm transportation service that will allow Eastern Shore the right not to schedule service for up to 90 days during the peak months of November through April each year
OTC: Over-the-counter
Peninsula Pipeline: Peninsula Pipeline Company, Inc., our wholly-owned Florida intrastate pipeline subsidiary
PESCO: Peninsula Energy Services Company, Inc., our wholly-owned natural gas marketing subsidiary
PSC: Public Service Commission, which is the state agency that regulates the rates and services provided by Chesapeake’s natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida
Sandpiper: Sandpiper Energy, Inc.
Sanford Group: FPU and other responsible parties involved with the Sanford environmental site
SEC: Securities and Exchange Commission
Sharp: Sharp Energy, Inc., our wholly-owned propane distribution subsidiary
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 March 31,	
	2015	2014
(in thousands, except shares and per share data)		
Operating Revenues		
Regulated Energy	$109,582	$102,166
Unregulated Energy and other	60,499	84,171
Total Operating Revenues	170,081	186,337
Operating Expenses		
Regulated Energy cost of sales	57,129	54,307
Unregulated Energy and other cost of sales	35,234	61,325
Operations	26,945	26,626
Maintenance	2,703	2,148
Depreciation and amortization	6,975	6,635
Other taxes	3,587	3,673
Total Operating Expenses	132,573	154,714
Operating Income	37,508	31,623
Other income, net of other expenses	133	6
Interest charges	2,448	2,155
Income Before Income Taxes	35,193	29,474
Income taxes	14,084	11,793
Net Income	$21,109	$17,681
Weighted Average Common Shares Outstanding:		
Basic	14,604,841	14,487,646
Diluted	14,656,310	14,540,151
Earnings Per Share of Common Stock:		
Basic	$1.45	$1.22
Diluted	$1.44	$1.22
Cash Dividends Declared Per Share of Common Stock	$0.270	$0.257

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 March 31,	
	2015	2014
(in thousands)		
Net Income	$21,109	$17,681
Other Comprehensive Income (Loss), net of tax:		
Employee Benefits, net of tax:		
Amortization of prior service cost, net of tax of $(7), $(6), respectively	(10)	(9)
Net gain, net of tax of $62 and $27, respectively	92	40
Cash Flow Hedges, net of tax:		
Unrealized gain on commodity contract cash flow hedges, net of tax of $17 and $0, respectively.	26	—
Total Other Comprehensive Income	108	31
Comprehensive Income	$21,217	$17,712

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	March 31, 2015	December 31, 2014
(in thousands, except shares)		
Property, Plant and Equipment		
Regulated Energy	$779,394	$766,855
Unregulated Energy	84,386	84,773
Other businesses and eliminations	19,459	18,497
Total property, plant and equipment	883,239	870,125
Less: Accumulated depreciation and amortization	(198,181)	(193,369)
Plus: Construction work in progress	24,137	13,006
Net property, plant and equipment	709,195	689,762
Current Assets		
Cash and cash equivalents	16,170	4,574
Accounts receivable (less allowance for uncollectible accounts of $1,274 and $1,120, respectively)	62,062	53,300
Accrued revenue	12,869	13,617
Propane inventory, at average cost	4,550	7,250
Other inventory, at average cost	4,411	3,699
Regulatory assets	7,472	8,967
Storage gas prepayments	910	4,258
Income taxes receivable	—	18,806
Prepaid expenses	4,510	6,652
Mark-to-market energy assets	46	1,055
Other current assets	294	195
Total current assets	113,294	122,373
Deferred Charges and Other Assets		
Goodwill	4,952	4,952
Other intangible assets, net	2,316	2,404
Investments, at fair value	3,770	3,678
Regulatory assets	78,113	78,136
Receivables and other deferred charges	2,067	3,164
Total deferred charges and other assets	91,218	92,334
Total Assets	$913,707	$904,469

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	March 31, 2015	December 31, 2014
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	$7,119	$7,100
Additional paid-in capital	156,749	156,581
Retained earnings	159,446	142,317
Accumulated other comprehensive loss	(5,568)	(5,676)
Deferred compensation obligation	1,715	1,258
Treasury stock	(1,715)	(1,258)
Total stockholders' equity	317,746	300,322
Long-term debt, net of current maturities	158,083	158,486
Total capitalization	475,829	458,808
Current Liabilities		
Current portion of long-term debt	9,116	9,109
Short-term borrowing	66,772	88,231
Accounts payable	46,284	44,610
Customer deposits and refunds	22,307	25,197
Accrued interest	3,109	1,352
Dividends payable	3,950	3,939
Income taxes payable	2,946	—
Deferred income taxes	586	832
Accrued compensation	4,845	10,076
Regulatory liabilities	18,621	3,268
Mark-to-market energy liabilities	20	1,018
Other accrued liabilities	7,797	6,603
Total current liabilities	186,353	194,235
Deferred Credits and Other Liabilities		
Deferred income taxes	160,055	160,232
Regulatory liabilities	43,518	43,419
Environmental liabilities	9,147	8,923
Other pension and benefit costs	34,798	35,027
Deferred investment tax credits and other liabilities	4,007	3,825
Total deferred credits and other liabilities	251,525	251,426
Other commitments and contingencies (Note 6)		
Total Capitalization and Liabilities	$913,707	$904,469

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

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

	Three Months Ended March 31, 2015	2014
(in thousands)		
Operating Activities		
Net income	$21,109	$17,681
Adjustments to reconcile net income to net operating cash:		
Depreciation and amortization	6,975	6,635
Depreciation and accretion included in other costs	1,689	1,783
Deferred income taxes, net	(496)	(231)
Realized gain on commodity contracts/sale of assets/investments	(840)	(8)
Unrealized loss on investments/commodity contracts	21	31
Employee benefits and compensation	300	162
Share-based compensation	537	638
Other, net	4	(1)
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	(8,014)	(3,647)
Propane inventory, storage gas and other inventory	5,337	8,243
Regulatory assets/liabilities, net	16,185	200
Prepaid expenses and other current assets	2,500	2,185
Accounts payable and other accrued liabilities	2,376	4,821
Income taxes receivable/payable	21,753	11,565
Customer deposits and refunds	(2,890)	(1,735)
Accrued compensation	(5,262)	(3,505)
Other assets and liabilities, net	2,753	1,246
Net cash provided by operating activities	64,037	46,063
Investing Activities		
Property, plant and equipment expenditures	(27,508)	(18,528)
Proceeds from sales of assets	198	29
Environmental expenditures	(49)	(26)
Net cash used in investing activities	(27,359)	(18,525)
Financing Activities		
Common stock dividends	(3,573)	(3,369)
Purchase of stock for Dividend Reinvestment Plan	27	(341)
Change in cash overdrafts due to outstanding checks	(2,191)	(501)
Net repayment under line of credit agreements	(19,269)	(21,696)
Repayment of long-term debt and capital lease obligation	(76)	(196)
Net cash used in financing activities	(25,082)	(26,103)
Net Increase in Cash and Cash Equivalents	11,596	1,435
Cash and Cash Equivalents—Beginning of Period	4,574	3,356
Cash and Cash Equivalents—End of Period	$16,170	$4,791

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, 2013	14,457,345	$4,691	$152,341	$124,274	$ (2,533)	$ 1,124	$(1,124)	$278,773
Net income	—	—	—	36,092	—	—	—	36,092
Other comprehensive loss	—	—	—	—	(3,143)	—	—	(3,143)
Dividend declared ($1.067 per share)	—	—	—	(15,675)	—	—	—	(15,675)
Retirement savings plan and dividend reinvestment plan	43,367	16	1,844	—	—	—	—	1,860
Conversion of debentures	47,313	15	520	—	—	—	—	535
Share-based compensation and tax benefit [2] [3]	40,686	13	1,876	—	—	—	—	1,889
Stock split in the form of stock dividend	—	2,365	—	(2,374)	—	—	—	(9)
Treasury stock activities	—	—	—	—	—	134	(134)	—
Balance at December 31, 2014	14,588,711	7,100	156,581	142,317	(5,676)	1,258	(1,258)	300,322
Net income	—	—	—	21,109	—	—	—	21,109
Other comprehensive income	—	—	—	—	108	—	—	108
Dividend declared ($0.27 per share) and dividend reinvestment plan	8,059	4	388	(3,980)	—	—	—	(3,588)
Share-based compensation and tax benefit [3]	31,219	15	(220)	—	—	—	—	(205)
Treasury stock activities	—	—	—	—	—	457	(457)	—
Balance at March 31, 2015	14,627,989	$7,119	$156,749	$159,446	$ (5,568)	$ 1,715	$(1,715)	$317,746

(1) Includes 53,442 and 53,125 shares at March 31, 2015 and December 31, 2014, 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 three months ended March 31, 2015 and for the year ended December 31, 2014, we withheld 12,620 and 12,687 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,” “we,” “us” and “our” are intended to mean Chesapeake Utilitie 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, 2014. 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.

Reclassifications

As a result of the sale of our advanced information services subsidiary in October 2014, we changed our operating segments (see Note 7, Segment Information). We reclassified certain amounts in the condensed consolidated income statement and condensed consolidated cash flows statement for the three months ended March 31, 2014 to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Stock Dividend

On July 2, 2014, our Board of Directors approved a three-for-two stock split of our outstanding common stock to be effected in the form of a stock dividend. Each stockholder as of the close of business on the record date, August 13, 2014, received one additional share of common stock for every two shares of common stock owned. The additional shares were distributed on September 8, 2014. All share and per share data in this Form 10-Q are presented on a post-split basis. As a result of the stock split, we reclassified approximately $2.4 million from retained earnings to common stock in September of 2014, which represents $0.4867 par value per share of the shares issued in the stock split.

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Standards Yet to be Adopted

Revenue from Contracts with Customers (ASC 606) - In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. This standard provides a single comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, as well as across industries and capital markets. The standard contains principles that entities will apply to determine the measurement of revenue and when it is recognized. On April 1, 2015, the FASB proposed to defer the implementation of this standard by one year, which if approved, would result in the new standard being effective for public entities for their 2018 interim and annual financial statements. We are assessing the impact this standard will have on our financial position and results of operations.

Interest - Imputation of Interest (ASC 835-30) - In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. This standard requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. ASU 2015-03 is effective for our interim and annual financial statements issued beginning January 1, 2016. Early adoption is permitted for financial statements that have not been previously issued. As of March 31, 2015, we had $333,000 of unamortized debt issuance costs included in the accompanying condensed consolidated balance sheets. Upon adoption of ASU 2015-03, this will be presented as a deduction from long-term debt, net of current maturities.

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2. Calculation of Earnings Per Share

	Three Months Ended March 31,	
	2015	2014
(in thousands, except shares and per share data)		
Calculation of Basic Earnings Per Share:		
Net Income	$21,109	$17,681
Weighted average shares outstanding	14,604,841	14,487,646
Basic Earnings Per Share	$1.45	$1.22
Calculation of Diluted Earnings Per Share:		
Reconciliation of Numerator:		
Net Income	$21,109	$17,681
Reconciliation of Denominator:		
Weighted shares outstanding—Basic	14,604,841	14,487,646
Effect of dilutive securities:		
Share-based compensation	51,469	52,505
Adjusted denominator—Diluted	14,656,310	14,540,151
Diluted Earnings Per Share	$1.44	$1.22

As discussed in Note 1, Summary of Accounting Policies, previously reported share and per share amounts have been restated in the accompanying condensed consolidated financial statements and related notes to reflect the stock split effected in the form of a stock dividend.

3. Acquisitions

Gatherco Acquisition

On April 1, 2015, we completed the merger with Gatherco, in which Gatherco merged with Aspire Energy of Ohio, a newly formed, wholly-owned subsidiary of Chesapeake. 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, and paid $27.6 million in cash. We also acquired $6.7 million of Gatherco's cash at the time of the closing and assumed $1.7 million of Gatherco’s debt, which was paid off shortly after closing. We incurred $1.3 million in transaction costs associated with this merger, $514,000 of which was expensed in the three months ended March 31, 2015. Transactions costs are included in operations expense in the accompanying condensed consolidated statement of income. As a result of this merger, Aspire Energy of Ohio provides natural gas midstream services through 16 gathering systems and over 2,000 miles of pipelines in Central and Eastern Ohio. Aspire Energy of Ohio provides natural gas gathering services and natural gas liquid processing services to over 300 producers, and supplies natural gas to over 6,000 customers in Ohio through the Consumers Gas Cooperative, an independent entity, which Aspire Energy of Ohio manages under an operating agreement. The results of Aspire Energy of Ohio are projected to have a minimal impact on our earnings per share in 2015, since the merger was completed after the first quarter. The first quarter includes key winter months, which have historically represented a significant portion of Gatherco's annual earnings. This acquisition is expected to be accretive to our earnings in the first full year of operations.

We are in the process of finalizing our evaluation of the tangible and intangible assets acquired and liabilities assumed, as well as the initial purchase price allocation as of the acquisition date, including the determination of any resulting goodwill. Therefore, this information cannot be provided at this time.

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’s 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
There were no significant rates and other regulatory activities in Delaware during the first quarter of 2015.
Maryland
There were no significant rates and other regulatory activities in Maryland during the first quarter of 2015.

Florida
On January 16, 2015, Chesapeake's Florida natural gas distribution division filed for approval with the Florida PSC a contract with Peninsula Pipeline, which is one of Chesapeake's subsidiaries, for additional natural gas transportation services in the vicinity of Haines City located in Polk County, Florida. This petition was approved by the Florida PSC at the Agenda Conference on May 5, 2015.
Eastern Shore
White Oak Mainline Expansion Project: On November 21, 2014, Eastern Shore submitted an application to the FERC for a CP seeking authorization to construct, own, operate and maintain the White Oak mainline expansion project. The project is designed to provide 45,000 Dts/d of firm transportation service to an industrial customer in Kent County, Delaware. Eastern Shore proposes to construct approximately 7.2 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and 3,550 horsepower of additional compression at Eastern Shore’s existing Delaware City Compressor Station in New Castle County, Delaware. The estimated cost of the project is $29.8 million. On January 22, 2015, the FERC issued a Notice of Intent to Prepare an Environmental Assessment for this project. The FERC solicited public participation with the comment period ending on February 23, 2015.

5. Environmental Commitments and Contingencies
We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remediate at current and former operating sites the effect on the environment of the disposal or release of specified substances.
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 March 31, 2015, we had approximately $10.1 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 $9.8 million of which has been recovered as of March 31, 2015, leaving approximately $4.2 million in regulatory assets for future recovery of environmental costs from FPU’s customers.
In addition to the FPU MGP sites, we had $369,000 in environmental liabilities at March 31, 2015 related to Chesapeake’s MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of March 31, 2015, we had approximately $216,000 in regulatory and other assets for future recovery through Chesapeake’s rates.
During the first quarter of 2015, we established $273,000 in environmental liabilities related to Chesapeake’s 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’s rates, although we have not yet sought approval for recovery by the Delaware PSC. As of March 31, 2015, we had approximately $252,000 in environmental liability and $273,000 in regulatory and other assets related to this site.
Environmental liabilities for all of our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental remediation and related activities, including any potential future remediation costs for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.
West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at, and in the immediate vicinity of, a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated a MGP. FPU is currently implementing a remedial plan approved by the FDEP for the east parcel of the West Palm Beach site,

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which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. It is anticipated that similar remedial actions will ultimately be implemented for other portions of the site. Estimated costs of remediation for the West Palm Beach site range from approximately $4.5 million to $15.4 million, including costs associated with the relocation of FPU’s operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP at this site. In January 2007, FPU and the Sanford Group signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. FPU’s share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of March 31, 2015, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

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

As of March 31, 2015, FPU’s remaining remediation expenses, including attorneys’ fees and costs, are estimated to be $24,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU’s asserted defense to liability for costs exceeding $13.0 million to implement the final remedy for this site, as provided in the Third Participation Agreement, or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of March 31, 2015.

Key West, Florida

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

In October 2012, FDEP issued a Remedial Action Plan approval order which specified that a limited semi-annual monitoring program be conducted. The most recent groundwater-monitoring event was conducted on March 23, 2015. Natural attenuation default criteria were met at all locations sampled. The next semi-annual sampling event is scheduled for September 2015.

Although the duration of the FDEP-required limited NAM cannot be determined with certainty, it is anticipated 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.

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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. It is anticipated that FPU’s share of remaining legal and cleanup costs will not exceed $5,000.

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 shut-down 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 Semi-Annual RAP Implementation Status Report submitted January 8, 2015. Although specific remedial actions have not yet been identified, we estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $443,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site. We continue to believe that the entire amount will be recoverable from customers through rates.

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

Salisbury, Maryland

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

Seaford, Delaware

In a letter dated December 5, 2013, the DNREC notified us that it will be conducting a facility evaluation of a former MGP site in Seaford, Delaware. In a report issued during January 2015, DNREC provided the evaluation of this site, which found contaminants impacting the groundwater. We are planning to enter this site into the Voluntary Cleanup Program. We estimate the cost of potential remedial actions, based on the findings of the DNREC report, to be $273,000 to $465,000.

Other

We are in discussions with the MDE regarding 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.

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. Our Delaware and Maryland natural gas distribution divisions have a contract through March 31, 2017 with an unaffiliated energy marketing and risk management company to manage a portion of their natural gas transportation and storage capacity.

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

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

Chesapeake’s 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 is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay the capacity charge.

In May 2014, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2015. PESCO is currently obtaining and reviewing proposals from suppliers and anticipates executing new agreements before the existing agreements expire.

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 March 31, 2015, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has authorized us to issue corporate guarantees securing obligations of our subsidiaries and to obtain letters of credit securing our obligations, including the obligations of our subsidiaries. The maximum authorized liability under such guarantees and letters of credit is $50.0 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which is for Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases, respectively, 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 March 31, 2015 was $31.1 million, with the guarantees expiring on various dates through February 28, 2016.

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

In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which expires on September 12, 2015, related to the electric transmission services for FPU’s northwest electric division. We have also issued a letter of credit to our current primary insurance company for $1.1 million, which expires on October 31, 2015, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for $40,000 to our former primary insurance company, which will expire on June 1, 2015. There have been no draws on these letters of credit as of March 31, 2015. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.3 million to TETLP related to the precedent agreement and firm transportation service agreement between our Delaware and Maryland divisions.

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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 March 31, 2015, we maintained a liability of $100,000 related to unrecognized income tax benefits and $578,000 related to contingencies for taxes other than income. As of December 31, 2014, we maintained a liability of $100,000 related to unrecognized income tax benefits and $724,000 related to contingencies for taxes other than income.

Other

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

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. Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

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

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The following table presents financial information about our reportable segments:

	Three Months Ended March 31,	
	2015	2014
(in thousands)		
Operating Revenues, Unaffiliated Customers		
Regulated Energy segment	$109,292	$101,874
Unregulated Energy segment	60,789	79,874
Other businesses	—	4,589
Total operating revenues, unaffiliated customers	$170,081	$186,337
Intersegment Revenues (1)		
Regulated Energy segment	$290	$292
Unregulated Energy segment	207	99
Other businesses	221	253
Total intersegment revenues	$718	$644
Operating Income		
Regulated Energy segment	$22,182	$21,091
Unregulated Energy segment	15,229	10,858
Other businesses and eliminations	97	(326)
Total operating income	37,508	31,623
Other income, net of other expenses	133	6
Interest	2,448	2,155
Income before Income Taxes	35,193	29,474
Income taxes	14,084	11,793
Net Income	$21,109	$17,681

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

(in thousands)	March 31, 2015	December 31, 2014
Identifiable Assets		
Regulated Energy segment	$788,600	$796,021
Unregulated Energy segment	89,950	84,732
Other businesses and eliminations	35,157	23,716
Total identifiable assets	$913,707	$904,469

Our operations are entirely domestic.

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8. Accumulated Other Comprehensive Income (Loss)

Defined benefit pension and postretirement plan items and unrealized gains (losses) of our propane swap agreements and call options, 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 three months ended March 31, 2015 and 2014. 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, 2014	$(5,643)	$(33)	$(5,676)
Other comprehensive loss before reclassifications	—	(7)	(7)
Amounts reclassified from accumulated other comprehensive loss	82	33	115
Net current-period other comprehensive income (loss)	82	26	108
As of March 31, 2015	$(5,561)	$(7)	$(5,568)

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2013	$(2,533)	$—	$(2,533)
Other comprehensive loss before reclassifications	—	—	—
Amounts reclassified from accumulated other comprehensive loss	31	—	31
Net current-period other comprehensive income	31	—	31
As of March 31, 2014	$(2,502)	$—	$(2,502)

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

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(in thousands)	Three Months Ended March 31, 2015	2014
Amortization of defined benefit pension and postretirement plan items:		
Prior service cost [1]	$17	$14
Net loss [1]	(154)	(66)
Total before income taxes	(137)	(52)
Income tax benefit	55	21
Net of tax	$(82)	$(31)
Gains and losses on commodity contracts cash flow hedges		
Propane swap agreements [2]	$12	$—
Call options [2]	(55)	—
Total before income taxes	(43)	—
Income tax benefit	17	—
Net of tax	(26)	—
Total reclassifications for the period	$(108)	$(31)

[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 months ended March 31, 2015 and 2014 are set forth in the following tables:

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended March 31,	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014
(in thousands)										
Interest cost	$102	$107	$626	$647	$23	$23	$11	$13	$15	$17
Expected return on plan assets	(135)	(133)	(777)	(773)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	2	5	(19)	(19)	—	—
Amortization of net loss	90	37	114	—	25	12	17	17	2	—
Net periodic cost (benefit)	57	11	(37)	(126)	50	40	9	11	17	17
Amortization of pre-merger regulatory asset	—	—	190	190	—	—	—	—	2	2
Total periodic cost	$57	$11	$153	$64	$50	$40	$9	$11	$19	$19

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We expect to record pension and postretirement benefit costs of approximately $1.2 million for 2015. Included in these costs is $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 merger. 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 $3.4 million and $3.6 million at March 31, 2015 and December 31, 2014, respectively. The amortization included in pension expense is also being added to a net periodic loss of $381,000, which will increase our total expected benefit costs to $1.2 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 merger. The portion of the unrecognized pension and postretirement benefit costs related to FPU's unregulated operations and Chesapeake's operations is recorded to accumulated other comprehensive income (loss). The following table presents the amounts included in the regulatory asset and accumulated other comprehensive income (loss) that were recognized as components of net periodic benefit cost during the three months ended March 31, 2015 and 2014:

For the Three Months Ended March 31, 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	90	114	25	17	2	248
Total recognized in net periodic benefit cost	$ 90	$114	$ 27	$ (2)	$2	$231
Recognized from accumulated other comprehensive loss [1]	$ 90	$22	$ 27	$ (2)	$—	$137
Recognized from regulatory asset	—	92	—	—	2	94
Total	$ 90	$114	$ 27	$ (2)	$2	$231

For the Three Months Ended March 31, 2014	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 5	$ (19)	$—	$(14)
Net loss	37	—	12	17	—	66
Total recognized in net periodic benefit cost	$ 37	$—	$ 17	$ (2)	$—	$52
Recognized from accumulated other comprehensive loss [1]	$ 37	$—	$ 17	$ (2)	$—	$52
Recognized from regulatory asset	—	—	—	—	—	—
Total	$ 37	$—	$ 17	$ (2)	$—	$52

(1) See Note 8, Accumulated Other Comprehensive Income (Loss).

During the three months ended March 31, 2015, we contributed $104,000 to the Chesapeake Pension Plan and $343,000 to the FPU Pension Plan. We expect to contribute a total of $475,000 and $1.6 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2015, which represent the minimum contribution payments required during the year.

The Chesapeake SERP, the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake SERP for the three months ended March 31, 2015, were $33,000. We expect to pay total cash benefits of approximately $151,000 under the Chesapeake Pension SERP in 2015. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three months ended March 31, 2015, were $15,000. We have estimated that approximately $79,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2015. Cash benefits paid for the FPU Medical Plan, primarily for medical claims

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for the three months ended March 31, 2015, were $92,000. We estimate that approximately $207,000 will be paid for such benefits under the FPU Medical Plan in 2015.

10. Investments

The investment balances at March 31, 2015 and December 31, 2014, consist of the Rabbi Trust associated with our Deferred Compensation Plan. We classify these investments as trading securities and report them at their fair value. For the three months ended March 31, 2015 and 2014, we recorded a net unrealized gain of $104,000 and $37,000, respectively, in other income in the condensed consolidated statements of income related to these investments. 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 Rabbi Trust.

11. Share-Based Compensation

Since May 2, 2013, our non-employee directors and key employees have been granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period.

The table below presents the amounts included in net income related to share-based compensation expense for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
(in thousands)		
Awards to non-employee directors	$150	$124
Awards to key employees	387	514
Total compensation expense	537	638
Less: tax benefit	(217)	(257)
Share-based compensation amounts included in net income	$320	$381

Non-employee Directors

Shares granted to non-employee directors are issued in advance of the directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2014, each of our non-employee directors received an annual retainer of 1,209 shares of common stock under the SICP. At March 31, 2015, there was $50,000 of unrecognized compensation expense related to these awards. This expense was fully recognized over the directors' remaining service periods ending April 30, 2015.

Key Employees

The table below presents the summary of the stock activity for awards to key employees for the three months ended March 31, 2015:

	Number of Shares	Weighted Average Fair Value
Outstanding—December 31, 2014	123,038	$32.60
Granted	29,763	$48.90
Vested	(43,839)	$28.01
Expired	(2,520)	$28.83
Outstanding—March 31, 2015	106,442	$38.17

In January 2015, our Board of Directors granted awards of 29,763 shares to key employees under the SICP. The shares granted in January 2015 are multi-year awards that will vest at the end of the three-year service period ending

December 31,

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2017. 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 date each award is granted. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

At March 31, 2015, the aggregate intrinsic value of the SICP awards granted to key employees was $5.4 million. At March 31, 2015, there was $2.3 million of unrecognized compensation cost related to these awards, which is expected to be recognized during 2015 through 2017.

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. Purchases under these contracts typically either do not meet the definition of derivatives or are considered “normal purchases and sales” and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory or cash flow hedges of its future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of March 31, 2015, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2015

In March 2015, Sharp entered into a put option to protect against a decline in propane prices and related potential inventory losses associated with 630,000 gallons committed to be purchased for the propane price cap program in the upcoming heating season. The put option is exercised if propane prices fall below the strike price of $0.4950 per gallon in December 2015 through February 2016. We will receive the difference between the market price and the strike price during those months. We paid $43,000 to purchase the put option. We accounted for the put option as a fair value hedge, and there is no ineffective portion of this hedge. As of March 31, 2015, the put option had a fair value of $38,000. The change in fair value of the put option effectively reduced our propane inventory balance.

In March 2015, 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 receives the difference between the index prices (Mont Belvieu prices in December 2015 through February 2016) and the swap price of $0.5950 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 hedge, and there is no ineffective portion of this hedge. At March 31, 2015, the swap agreement had a liability fair value of $12,000. The change in the fair value of the swap agreement is recorded as unrealized gain/loss in other comprehensive income (loss).

Hedging Activities in 2014

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

In May 2014, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 630,000 gallons we expected to purchase for the upcoming heating season. Under these swap agreements, Sharp would have received the difference between the index prices (Mont Belvieu prices in December 2014 through February 2015) and the swap prices of $1.1350, $1.0975 and $1.0475 per gallon for each swap agreement, to the extent the index prices exceeded the swap prices. If the index prices were lower than the swap prices, Sharp would pay the difference. These swap agreements essentially fixed the price of those 630,000 gallons purchased for the upcoming heating season. We had initially accounted for them as cash flow hedges as the swap agreements met all the requirements. We paid $1.1 million, representing the difference between the market prices and strike prices during those months for the swap agreements. At December 31, 2014, we elected to discontinue hedge accounting on the swap agreements and reclassified $735,000 of unrealized loss from other comprehensive loss to propane cost of sales. Subsequently, we

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accounted for them as derivative instruments on a mark-to-market basis with the change in the fair value reflected in current period earnings.

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

Commodity Contracts for Trading Activities

Xeron engages in trading activities using forward and futures contracts. 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 statement of income for the period of change. As of March 31, 2015, we had the following outstanding trading contracts, which we accounted for as derivatives:

At March 31, 2015	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	420,000	$0.4788	$0.4788
Purchase	421,000	$0.4775	$0.4789

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the second quarter of 2015.

Xeron has 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 March 31, 2015, Xeron had a right to offset $1.9 million and $2.3 million of accounts receivable and accounts payable, respectively, with these two counterparties. At December 31, 2014, Xeron had a right to offset $1.6 million and $1.2 million of accounts receivable and accounts payable, respectively, with these two counterparties.

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit-risk-related contingency.

The fair values of the derivative contracts recorded in the condensed consolidated balance sheets as of March 31, 2015 and December 31, 2014, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	March 31, 2015	December 31, 2014
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$8	$407
Derivatives designated as fair value hedges			
Put option(s)	Mark-to-market energy assets	38	622
Derivatives designated as cash flow hedges			
Call option	Mark-to-market energy assets	—	26
Total asset derivatives		$46	$1,055

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	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	March 31, 2015	December 31, 2014
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$8	$283
Propane swap agreements	Mark-to-market energy liabilities	—	735
Derivatives designated as cash flow hedges			
Propane swap agreement	Mark-to-market energy liabilities	12	—
Total liability derivatives		$20	$1,018

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

	Location of Gain	Amount of Gain (Loss) on Derivatives: For the Three Months Ended March 31,	
(in thousands)	(Loss) on Derivatives	2015	2014
Derivatives not designated as hedging instruments			
Realized gain on forward contracts [1]	Revenue	$ 277	$ 1,246
Unrealized loss on forward contracts	Revenue	(125)	(68)
Call option	Cost of sales	—	137
Propane swap agreements	Cost of sales	(717)	—
Derivatives designated as fair value hedges			
Put options	Cost of sales	506	(20)
Put option [2]	Propane Inventory	(3)	—
Derivatives designated as cash flow hedges			
Propane swap agreement	Other Comprehensive loss	(12)	—
Call options	Cost of sales	(81)	—
Total		$ (155)	$ 1,295

(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 put 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:

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 March 31, 2015 and December 31, 2014:

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As of March 31, 2015	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—guaranteed income fund	$280	$—	$—	$280
Investments—other	$3,490	$3,490	$—	$—
Mark-to-market energy assets, incl. put/call options	$46	$—	$46	$—
Liabilities:				
Mark-to-market energy liabilities incl. swap agreements	$20	$—	$20	$—

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

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

Level 1 Fair Value Measurements:

Investments- equity securities—The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities.

Investments- other—The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.

Level 2 Fair Value Measurements:

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

Propane put/call options and swap agreements—The fair value of the propane put/call options and swap agreements are determined using market transactions for similar assets and liabilities in either the listed or OTC markets.

Level 3 Fair Value Measurements:

Investments- guaranteed income fund—The fair values of these investments are recorded at the contract value, which approximates their fair value.

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

	Three Months Ended March 31,	
	2015	2014
(in thousands)		
Beginning Balance	$287	$458
Purchases and adjustments	(5)	(94)
Transfers	(3)	—
Investment income	1	1
Ending Balance	$280	$365

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

At March 31, 2015, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).

At March 31, 2015, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of $161.4 million. This compares to a fair value of $182.2 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, and with adjustments for duration, optionality, and risk profile. At December 31, 2014, long-term debt, including the current maturities but excluding a capital lease obligation, had a carrying value of $161.5 million, compared to the estimated fair value of $180.7 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

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14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	March 31, 2015	December 31, 2014
FPU secured first mortgage bonds [(1)] :		
9.08% bond, due June 1, 2022	$7,971	$7,969
Uncollateralized senior notes:		
6.64% note, due October 31, 2017	8,182	8,182
5.50% note, due October 12, 2020	12,000	12,000
5.93% note, due October 31, 2023	27,000	27,000
5.68% note, due June 30, 2026	29,000	29,000
6.43% note, due May 2, 2028	7,000	7,000
3.73% note, due December 16, 2028	20,000	20,000
3.88% note, due May 15, 2029	50,000	50,000
Promissory notes	238	314
Capital lease obligation	5,808	6,130
Total long-term debt	167,199	167,595
Less: current maturities	(9,116)	(9,109)
Total long-term debt, net of current maturities	$158,083	$158,486

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

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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, 2014, 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 recovered in rates;
- the loss of customers due to 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 consequential hostilities or other 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 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 to the asset values and resulting higher costs and funding obligations of the Company's pension and other postretirement benefit plans as a result of potential downturns in the financial markets, lower discount rates or impacts associated with the Patient Protection and Affordable Care Act;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- 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 distribution, wholesale marketing and energy trading businesses;
- the effect of competition on our businesses;

- the ability to construct facilities at or below estimated costs; and
- risks related to cyber-attack or failure of information technology systems.

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Introduction

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

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

- executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;
- expanding the propane distribution business in existing and new markets through leveraging our community gas system services and our bulk delivery capabilities;
- expanding both our regulated energy and unregulated energy businesses through strategic acquisitions;
- utilizing our expertise across our various businesses to improve overall performance;
- pursuing and entering new unregulated energy markets and business lines that will complement our existing strategy and operating units;
- 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;
- maintaining a consistent and competitive dividend for shareholders; 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.

As a result of the sale of BravePoint in October 2014, we no longer report the Other segment.

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 cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities. Gross margin should not be considered an alternative to operating income or net income, which is determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by us under our allowed rates for regulated energy operations and under our competitive pricing structure for non-regulated segments. Our management uses gross margin in measuring our business units’ performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

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

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

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Results of Operations for the Three Months ended March 31, 2015

Overview and Highlights

Our net income for the quarter ended March 31, 2015 was $21.1 million, or $1.44 per share. This represents an increase of $3.4 million, or $0.22 per share, compared to net income of $17.7 million, or $1.22 per share, as reported for the same quarter in 2014. The increase in operating income from both the Regulated Energy and Unregulated Energy segments was a key driver in our net income growth. For the first quarter of 2015, operating income increased by $5.9 million, or 18.6 percent, to $37.5 million.

	Three Months Ended March 31,		
	2015	2014	Increase
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$22,182	$21,091	$1,091
Unregulated Energy segment	15,229	10,858	4,371
Other businesses and eliminations	97	(326)	423
Operating Income	37,508	31,623	5,885
Other Income, net of Other Expenses	133	6	127
Interest Charges	2,448	2,155	293
Pre-tax Income	35,193	29,474	5,719
Income Taxes	14,084	11,793	2,291
Net Income	$21,109	$17,681	$3,428
Earnings Per Share of Common Stock			
Basic	$1.45	$1.22	$0.23
Diluted	$1.44	$1.22	$0.22

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Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
First Quarter of 2014 Reported Results	$29,474	$17,681	$1.22
Adjusting for Unusual Items:			
Absence of BravePoint, which was sold in October 2014	438	263	0.02
Weather impact	330	198	0.01
	768	461	0.03
Increased (Decreased) Gross Margins:			
Higher retail propane margins	5,020	3,011	0.21
Service expansions (See Major Projects Highlights table)	1,431	858	0.06
Other natural gas growth	1,327	796	0.05
FPU Electric base rate increase	1,212	727	0.05
Propane wholesale marketing	(1,026)	(615)	(0.04)
GRIP	755	453	0.03
	8,719	5,230	0.36
Increased Other Operating Expenses:			
Higher payroll costs	(814)	(488)	(0.04)
Higher service contractor costs	(769)	(461)	(0.03)
Transaction costs	(514)	(308)	(0.02)
Higher facility maintenance	(466)	(280)	(0.02)
Higher depreciation, asset removal and property tax costs due to new capital investments	(463)	(278)	(0.02)
	(3,026)	(1,815)	(0.13)
Interest Charges	(292)	(175)	(0.01)
Net Other Changes	(450)	(273)	(0.03)
First Quarter of 2015 Reported Results	$35,193	$21,109	$1.44

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Summary of Key Factors

The following information highlights certain key factors contributing to our results for the current and future periods.

Major Projects

Service Expansions

During 2014, Eastern Shore, our interstate pipeline subsidiary, executed a one-year contract with an industrial customer in New Castle County, Delaware to provide 50,000 Dts/d of additional transmission service from April 2014 to April 2015. This contract was subsequently amended to provide 55,580 Dts/d of transmission service through August 2020. This contract generated gross margin of $731,000 for the three months ended March 31, 2015, and is expected to generate $2.3 million of gross margin in 2015.

In December 2014, Eastern Shore executed another short-term contract with the same customer in New Castle County, Delaware to provide an additional 10,000 Dts/d of OPT ≤ 90 Service from December 2014 to March 2015. The OPT ≤ 90 Service is a new firm transportation service that allows Eastern Shore not to schedule service for up to 90 days during the peak months of November through April each year. This short-term contract generated additional gross margin of $237,000 for the three months ended March 31, 2015.

On October 1, 2014, Eastern Shore commenced a new lateral service to an industrial customer facility in Kent County, Delaware. This service commenced after construction of new facilities, including approximately 5.5 miles of pipeline lateral and metering facilities, extending from Eastern Shore's mainline to the new industrial customer facility. This new service generated $463,000 of gross margin for the three months ended March 31, 2015. On an annual basis, this new service is expected to generate $1.8 million of gross margin in 2015 and annual gross margin of approximately $1.2 million to $1.8 million during the 37-year service period.

The following Major Project Highlights table summarizes our major projects initiated since 2014 (dollars in thousands):

	Gross Margin for the Period [1] Three Months Ended March 31, 2015	2014	Variance	Estimate for 2015	Total 2014 Margin
Acquisition:					
Gatherco acquisition being served by Aspire Energy of Ohio	$—	$—	$—	$8,797	$—
Service Expansions					
Natural Gas Transmission:					
Short-term					
New Castle County, Delaware	$968	$—	$968	$2,509	$2,026
Long-term					
Kent County, Delaware	463	—	463	1,844	463
Total Service Expansions	$1,431	$—	$1,431	$4,353	$2,489
Total Major Projects	$1,431	$—	$1,431	$13,150	$2,489

[1] Gross margin of $7.3 million and $21.8 million for the three months ended March 31, 2014 and the year ended December 31, 2014, respectively, related to projects initiated prior to 2014, which were previously disclosed, is excluded from the above table as those projects no longer result in period-over-period variances.

Future Service Expansion Initiatives

Eight Flags Energy, one of our unregulated energy subsidiaries, is engaged in the development and construction of a CHP plant in Nassau County, Florida. This CHP plant, which will consist of a natural-gas-fired turbine and associated electric generator, is designed to generate approximately 20 megawatts of base load power and will include a heat recovery system generator capable of providing approximately 75,000 pounds per hour of unfired steam. Eight Flags will sell the power generated from the CHP plant to FPU for distribution to its retail electric customers pursuant to a 20-year power purchase agreement. It will also sell the steam to an industrial customer pursuant to a separate 20-year contract. FPU will transport natural gas through its distribution system to Eight Flags' CHP plant, which will produce power and steam. On a consolidated basis, this project is expected to generate

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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. In March 2015, Eight Flags and the industrial customer held a groundbreaking ceremony. Eight Flags' CHP plant is expected to be operational in mid-2016. Our total projected investment, by Eight Flags and other Chesapeake affiliates, to construct the CHP plant and associated facilities is approximately $40.0 million.

In December 2014, Eastern Shore entered into a precedent agreement with an industrial customer in Kent County, Delaware, whereby the customer has committed to enter into a 20-year natural gas transmission service for 45,000 Dts/d for its new facility, upon the satisfaction of certain conditions. This new service will be provided as OPT ≤ 90 Service and is expected to generate at least $5.8 million of annual gross margin. In November 2014, Eastern Shore requested FERC's authorization to construct 7.2 miles of 16-inch pipeline looping and 3,550 horsepower of new compression in Delaware. The cost of these new facilities is estimated to be approximately $30 million. Eastern Shore anticipates receiving FERC’s authorization in 2015, with service targeted to commence in the late first quarter or early second quarter of 2016, following construction of the new facilities.

The following table summarizes our future major expansion initiatives and opportunities with executed contracts (dollars in thousands):

Project	Estimated In Service Date	Projected Capital Cost	Estimated Annualized Margin	Estimated Margin for 2015
20-year OPT ≤ 90 Service to an industrial customer in Kent County, Delaware	Late first quarter or early second quarter of 2016	$30.0 million	$5.8 million	$—
Eight Flags CHP plant in Nassau County, Florida	Third quarter of 2016	$40.0 million	$7.3 million	$—

Other Natural Gas Growth

In addition to these service expansions, the natural gas distribution operations on the Delmarva Peninsula and in Florida generated $450,000 and $690,000, respectively, in additional gross margin in the first quarter of 2015, compared to the same quarter in 2014, due to increases in the number of residential, commercial and industrial customers served. These increases are due primarily to a 2.7-percent increase in residential customers on the Delmarva Peninsula and an increase in commercial and industrial customers in Worcester County, Maryland and in Florida.

Acquisition

On April 1, 2015, we completed the merger with Gatherco, pursuant to which Gatherco merged with Aspire Energy of Ohio, our newly formed, wholly-owned subsidiary. At closing, we issued 592,970 shares of our common stock, valued at $30.2 million based on the closing price of our common stock as reported on the NYSE on April 1, 2015, and paid $27.6 million in cash. We also acquired $6.7 million of Gatherco's cash at the time of the closing and assumed $1.7 million of Gatherco’s debt, which was paid off shortly after closing. We incurred $1.3 million in transaction costs associated with this merger, $514,000 of which was expensed in the three months ended March 31, 2015. As a result of this merger, Aspire Energy of Ohio provides unregulated natural gas midstream services through 16 gathering systems and over 2,000 miles of pipelines in Central and Eastern Ohio. Aspire Energy of Ohio provides natural gas gathering services and natural gas liquid processing services to over 300 producers, and supplies natural gas to over 6,000 customers in Ohio through the Consumers Gas Cooperative, an independent entity, which Aspire Energy of Ohio manages under an operating agreement. The results of Aspire Energy of Ohio are projected to have a minimal impact on our earnings per share in 2015, since the merger was completed after the first quarter. The first quarter includes key winter months, which have historically represented a significant portion of Gatherco's earnings. This acquisition is expected to be accretive to our earnings in the first full year of operations.

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Weather and Consumption

The first quarter of 2015 and 2014 were both significantly colder than normal (10-year average weather) on the Delmarva Peninsula. However, since weather on the Delmarva Peninsula was significantly colder in both years, it was not a significant factor in quarter-over-quarter variance. Compared to the same quarter in 2014, temperatures during the first quarter of 2015 were approximately 3.9 percent colder on the Delmarva Peninsula and were approximately 10.1 percent warmer in Florida, as measured by HDD. The impact of colder weather on the Delmarva Peninsula was offset by the impact of warmer weather in Florida. The following tables highlight the HDD and CDD information for the three months ended March 31, 2015 and 2014 and the gross margin variance resulting from weather fluctuations in those periods.

HDD and CDD Information

	Three Months Ended March 31, 2015	2014	Variance
Delmarva			
Actual HDD	2,822	2,717	105
10-Year Average HDD ("Normal")	2,372	2,361	11
Variance from Normal	450	356	
Florida			
Actual HDD	501	557	(56)
10-Year Average HDD ("Normal")	533	529	4
Variance from Normal	(32)	28	
Florida			
Actual CDD	122	42	80
10-Year Average CDD ("Normal")	73	74	(1)
Variance from Normal	49	(32)	

Gross Margin Variance attributed to Weather

(in thousands)	Q1 2015 vs. Q1 2014	Q1 2015 vs. Normal
Delmarva		
Regulated Energy segment	$85	$1,088
Unregulated Energy segment	358	1,185
Florida		
Regulated Energy segment	(103)	(448)
Unregulated Energy segment	(10)	122
Total	$330	$1,947

Propane prices

Higher quarter-over-quarter retail margins per gallon generated $4.6 million in additional gross margin by the Delmarva propane distribution operation. A large decline in propane prices in the first quarter of 2015, compared to the same quarter in 2014, had a significant impact on the amount of revenue and cost of sales associated with our propane distribution operations. Based on the Mont Belvieu wholesale propane index, propane prices in the first quarter of 2015 were approximately 59 percent lower than prices in the same quarter in 2014. As a result of favorable supply management and hedging activities, the Delmarva propane distribution operation experienced a decrease in its average propane inventory cost in addition to the decrease in wholesale prices, which generated increased retail margins per gallon. Our retail pricing strategy is guided by local market conditions, which further increased margins in the first quarter of 2015. These market conditions, which include competition with other propane suppliers as well as the availability and price of alternative energy sources, may fluctuate based on changes in demand, supply and other energy commodity prices. The level of retail margins generated during the first quarter of 2015 is not typical and, therefore, is not included in our long-term financial plans or forecasts.

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Xeron, which benefits from wholesale price volatility by entering into trading transactions, experienced a quarter-over-quarter gross margin decrease of $1.0 million for the three months ended March 31, 2015 due to lower wholesale price volatility.

Regulatory Initiatives

GRIP

GRIP is a 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 natural gas distribution systems. This program allows recovery through rates of capital and other program-related costs, inclusive of a return on investment, associated with the replacement of the mains and services. Since the program's inception in August 2012, our Florida natural gas distribution operations have invested $52.4 million to replace 113 miles of qualifying distribution mains, $8.4 million of which was invested during the first quarter of 2015. We expect to invest an additional $11.6 million in this program through the end of 2015. The increased investment in GRIP generated additional gross margin of $755,000 for the three months ended March 31, 2015, compared to the same quarter in 2014.

Florida Electric Rate Case

On September 15, 2014, the Florida PSC approved a settlement agreement between FPU and the Florida Office of Public Counsel in FPU's base rate case filing for its electric operation, which included, among other things, an increase in FPU's annual revenue requirement of approximately $3.8 million and a 10.25 percent rate of return on common equity. The new rates became effective for all meter reads on or after November 1, 2014. Previously, the Florida PSC approved interim rate relief, effective for meter readings on or after August 10, 2014. The higher base rates in FPU's electric operation generated $1.2 million in additional gross margin for the quarter ended March 31, 2015.

Capital Expenditures

For 2015, we budgeted approximately $223.4 million for capital expenditures. In comparison to the average level of capital expenditures over the past three years of $94.8 million, the 2015 capital budget represents a significant increase. Major projects currently underway, such as Eight Flags' CHP plant and associated facilities, anticipated new facilities to serve an industrial customer in Kent County, Delaware under the OPT ≤ 90 Service, and additional GRIP investments projected in 2015, account for approximately $90.0 million of the 2015 capital budget. Other expansions of natural gas distribution and transmission systems, additional infrastructure and facility improvements and other strategic initiatives and investments, account for the remainder of the capital budget. The capital expenditures are subject to continuous review and modification by our management and Board of Directors. Certain anticipated capital expenditures are subject to approval by the applicable regulators. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, changes in customer expectations or service needs, 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. In the past three years, our actual capital expenditures were between 82 percent and 88 percent of the originally budgeted amounts.

In order to fund the 2015 capital expenditures currently budgeted, we expect to increase the level of borrowings during 2015 to supplement cash provided by operating activities. We will look at other financing options as needed. Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent and we have maintained our equity between 54 percent and 60 percent of total capitalization, including short-term borrowings, in the past three years. If we increase the level of debt during 2015 to fund the budgeted capital expenditures, the ratio of equity to total capitalization, including short-term borrowings, will temporarily decline until we issue equity. The timing of any equity issuance(s) will be based on market conditions. We will seek to align, as much as feasible, any such equity issuance(s) with the commencement of service, and associated earnings, for larger revenue generating projects.

Regulated Energy Segment

For the quarter ended March 31, 2015 compared to 2014

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	Three Months Ended March 31, 2015	2014	Increase (decrease)
(in thousands)			
Revenue	$109,582	$102,166	$7,416
Cost of sales	57,129	54,307	2,822
Gross margin	52,453	47,859	4,594
Operations & maintenance	21,283	18,402	2,881
Depreciation & amortization	5,900	5,527	373
Other taxes	3,088	2,839	249
Other operating expenses	30,271	26,768	3,503
Operating income	$22,182	$21,091	$1,091

Operating income for the Regulated Energy segment for the quarter ended March 31, 2015 was $22.2 million, an increase of $1.1 million, or 5.2 percent, compared to the same quarter in 2014. The increased operating income reflects additional gross margin of $4.6 million, which was partially offset by an increase in other operating expenses of $3.5 million to support the growth.

Gross Margin

Items contributing to the quarter-over-quarter increase of $4.6 million, or 9.6 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended March 31, 2014	$47,859
Factors contributing to the gross margin increase for the three months ended March 31, 2015:	
Service expansions	1,431
Other natural gas growth	1,328
FPU electric base rate increase	1,212
Additional revenue from GRIP in Florida	755
Other	(132)
Gross margin for the three months ended March 31, 2015	$52,453

Service Expansions

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

- $731,000 from a short-term contract with an existing industrial customer in New Castle County, Delaware to provide 50,000 Dts/d of service from April 2014 to April 2015. This contract was subsequently amended to provide 55,580 Dts/d of service to August 2020 and is expected to generate $2.3 million of gross margin in 2015.
- $463,000 from a new service to an industrial customer facility in Kent County, Delaware that commenced on October 1, 2014, upon completion of new facilities, which includes approximately 5.5 miles of pipeline lateral and metering facilities, extending from Eastern Shore's mainline to the new industrial customer facility. This new service is expected to generate $1.8 million of gross margin in 2015.
- $237,000 from another short-term contract with the same industrial customer in New Castle County, Delaware, mentioned above, to provide an additional 10,000 Dts/d of OPT≤90 Service transmission service from December 2014 to March 2015.

Other Natural Gas Growth

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

- $690,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers; and
- $450,000 from a 2.7-percent increase in residential customers in the Delmarva natural gas distribution operations, as well as growth in commercial and industrial customers in Worcester County, Maryland.

FPU Electric Base Rate Increase

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FPU's electric distribution operation generated additional gross margin of $1.2 million due to higher base rates approved in September 2014 as a result of the rate case settlement. The new rates became effective for all meter reads on or after November 1, 2014.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2014 and 2015 by our Florida natural gas distribution operations generated $755,000 in additional gross margin.

Other Operating Expenses

The increase in other operating expenses was due primarily to:

- $594,000 in higher payroll costs as a result of additional personnel to support growth and increased overtime on the Delmarva Peninsula due to colder weather;
- $585,000 in higher contractor costs related to increased pipeline integrity assessment and the timing of certain maintenance activities;
- $523,000 in higher depreciation, asset removal and property tax costs associated with capital investments to support growth;
- $461,000 in transaction costs related to the Gatherco acquisition that were allocated to this segment;
- $368,000 in higher costs associated with maintaining facilities and operating systems; and
- $261,000 in legal and consulting costs associated with ongoing negotiations associated with a customer billing system implementation.

Unregulated Energy Segment

For the quarter ended March 31, 2015 compared to 2014

	Three Months Ended March 31,		Increase
	2015	2014	(decrease)
(in thousands)			
Revenue	$60,996	$79,973	$(18,977)
Cost of sales	35,677	59,159	(23,482)
Gross margin	25,319	20,814	4,505
Operations & maintenance	8,557	8,424	133
Depreciation & amortization	1,051	980	71
Other taxes	482	552	(70)
Other operating expenses	10,090	9,956	134
Operating Income	$15,229	$10,858	$4,371

Operating income for the Unregulated Energy segment increased by $4.4 million, or 40.3 percent, to $15.2 million in the first quarter of 2015, compared to $10.9 million in the same quarter of 2014. The increased operating income was driven by an increase in gross margin of $4.5 million.

Gross Margin

A significant decline in natural gas and propane commodity prices decreased both revenue and related cost of commodities from sales to our propane distribution and natural gas marketing customers. Items contributing to the quarter-over-quarter increase of $4.5 million, or 21.6 percent, in gross margin are listed in the following table:

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(in thousands)	
Gross margin for the three months ended March 31, 2014	$20,814
Factors contributing to the gross margin increase for the three months ended March 31, 2015:	
Increased retail propane margins	5,020
Lower propane wholesale marketing results	(1,026)
Increased customer consumption - weather and other	870
Decreased wholesale propane sales	(406)
Other	47
Gross margin for the three months ended March 31, 2015	$25,319

Increased Retail Propane Margins

Higher retail propane margins for our Delmarva Peninsula and Florida propane distribution operations during the first quarter of 2015 generated $4.6 million and $433,000, respectively, in additional gross margin. As a result of favorable supply management and hedging activities, the Delmarva propane distribution operation experienced a decrease in its average propane inventory cost in addition to the decrease in wholesale prices, which generated increased retail margins per gallon. Our retail pricing strategy is guided by local market conditions, which in the first quarter of 2015 further increased margins. These market conditions, which include competition with other propane suppliers, as well as the availability and price of alternative energy sources, may fluctuate based on changes in demand, supply and other energy commodity prices. The level of retail margins generated during the first quarter of 2015 is not typical and therefore, is not included in our long-term financial plans or forecasts.

Lower Propane Wholesale Marketing Results

Xeron's gross margin decreased by $1.0 million during the first quarter of 2015, compared to the same quarter in 2014, as a result of 44-percent decrease in trading activity and lower margins on executed trades. In contrast, Xeron experienced higher price volatility and higher trading volumes in the first quarter of 2014, which resulted in unusually high profitability during that period.

Increased Customer Consumption - Weather and Other

Increased customer consumption of propane due to colder temperatures and the timing of bulk deliveries on the Delmarva Peninsula generated $870,000 in additional gross margin.

Decreased Wholesale Propane Sales

Margins per gallon on the Delmarva wholesale propane sales decreased during the first quarter of 2015, compared to the same quarter in 2014, as a result of a decline in the price difference between local wholesale prices and the Company's inventory cost.

Other Operating Expenses

Other operating expenses increased slightly by $134,000.

Interest Charges

Interest charges for the first quarter of 2015 increased by approximately $293,000, or 14 percent, compared to the same quarter in 2014. The increase in interest charges is attributable to an increase of $332,000 in long-term interest charges as a result of the $50.0 million Notes issued in May 2014.

Income Taxes

Income tax expense was $14.1 million in the first quarter of 2015, compared to $11.8 million in the same quarter in 2014. The increase in income tax expense was due primarily to higher taxable income. Our effective income tax rate remained unchanged at 40.0 percent for the first quarters of 2015 and 2014.

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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 finance capital expenditures.

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

Our largest capital requirements are for investments in new or acquired plant and equipment. We have budgeted $223.4 million for capital expenditures during 2015. The following table shows the projected 2015 capital expenditures by segment:

(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$73,379
Natural gas transmission	93,041
Electric distribution	9,646
Total Regulated Energy	176,066
Unregulated Energy:	
Propane distribution	6,219
Other unregulated energy	33,033
Total Unregulated Energy	39,252
Other	8,047
Total 2015 projected capital expenditures	$223,365

The significant increase in our 2015 capital budget, compared to our historic capital expenditures in the past three years, is due to expansions of our natural gas distribution and transmission systems, increased natural gas infrastructure improvement activities, improvement of our facilities and systems and other strategic initiatives and investments expected in 2015. The capital expenditures program is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts.

The merger with Gatherco, which we completed on April 1, 2015, is not included in the 2015 capital expenditure budget shown above. 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, and paid $27.6 million in cash. We also acquired $6.7 million of Gatherco's cash at the time of the closing and assumed $1.7 million of Gatherco’s debt, which was paid off shortly after closing.

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Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of March 31, 2015 and December 31, 2014:

	March 31, 2015			December 31, 2014		
(in thousands)						
Long-term debt, net of current maturities	$158,083	33	%	$158,486	35	%
Stockholders' equity	317,746	67	%	300,322	65	%
Total capitalization, excluding short-term debt	$475,829	100	%	$458,808	100	%

	March 31, 2015			December 31, 2014		
(in thousands)						
Short-term debt	$66,772	12	%	$88,231	16	%
Long-term debt, including current maturities	167,199	30	%	167,595	30	%
Stockholders' equity	317,746	58	%	300,322	54	%
Total capitalization, including short-term debt	$551,717	100	%	$556,148	100	%

Included in the long-term debt balances at March 31, 2015 and December 31, 2014, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($4.5 million and $4.8 million, respectively, net of current maturities and $5.8 million and $6.1 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.

In order to fund the 2015 capital expenditures, which is currently budgeted at $223.4 million, we expect to increase the level of borrowings during 2015 to supplement cash provided by operating activities. We will look at other financing options as needed. Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent and we have maintained our equity between 54 percent and 60 percent of total capitalization, including short-term borrowings, in the past three years. If we increase the level of debt during 2015 to fund the budgeted capital expenditures, the ratio of equity to total capitalization, including short-term borrowings, will temporarily decline until we issue equity. The timing of any equity issuance(s) will be based on market conditions. We will seek to align, as much as feasible, any such equity issuance(s) with the commencement of service, and associated earnings, for larger revenue generating projects.

Short-term Borrowings

Our outstanding short-term borrowings at March 31, 2015 and December 31, 2014 were $66.8 million and $88.2 million, respectively, at weighted average interest rates of 1.09 percent and 1.15 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. We have six unsecured bank credit facilities with three financial institutions with $210.0 million of total available credit. Three of these credit facilities, totaling $120.0 million, are available under committed lines of credit. Two of these credit facilities, totaling $40.0 million, are available under uncommitted lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. In addition to these bank lines of credit, one of the lenders has made available a $50.0 million short-term revolving credit note. We are currently authorized by our Board of Directors to borrow up to $200.0 million of short-term borrowings, as required.

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Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
(in thousands)		
Net cash provided by (used in):		
Operating activities	$64,037	$46,063
Investing activities	(27,359)	(18,525)
Financing activities	(25,082)	(26,103)
Net increase in cash and cash equivalents	11,596	1,435
Cash and cash equivalents—beginning of period	4,574	3,356
Cash and cash equivalents—end of period	$16,170	$4,791

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 and deferred income taxes and working capital. Changes in working capital are determined by a variety of factors, including weather, the prices of natural gas, electricity and propane, the timing of customer collections, payments for purchases of natural gas, electricity and propane, and deferred fuel cost recoveries. During the three months ended March 31, 2015 and 2014, net cash provided by operating activities was $64.0 million and $46.1 million, respectively, resulting in an increase in cash flows of $18.0 million. Significant operating activities generating the cash flow change were as follows:

- The changes in net regulatory assets and liabilities increased cash flows by $16.0 million, due primarily to a change in fuel costs collected through the various fuel cost recovery mechanisms.
- The change in income taxes receivable increased cash flows by $10.2 million, due primarily to the receipt of a large tax refund related to our 2014 income tax obligation. Our tax deductions, which were higher-than-projected, due to bonus depreciation (approved by the President in December 2014), reduced our 2014 federal income tax obligation.
- The changes in net accounts receivable and payable decreased cash flows by $6.8 million, due to the timing of the collections and payments associated with trading contracts entered into by our propane wholesale marketing subsidiary and a decrease in net cash flows from receivables and payables in various other operations.
- Net income, adjusted for reconciling activities, increased cash flows by $2.6 million, due primarily to higher earnings.
- Net cash flows from changes in propane, natural gas and materials inventories decreased by approximately $2.9 million, compared to 2014.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $27.4 million and $18.5 million during the three months ended March 31, 2015 and 2014, respectively, resulting in a decrease in cash flows of $8.9 million. An increase in cash paid for capital expenditures, primarily for our natural gas distribution operations and Eight Flags' construction of the CHP plant, decreased cash flows by $9.0 million.

Cash Flows Provided by Financing Activities

Net cash used in financing activities totaled $25.1 million in the first three months of 2015, compared to $26.1 million in the same period in 2014. This resulted in an increase of $1.0 million in cash flows, due primarily to $2.4 million in lower repayments under our line of credit agreements, partially offset by $1.7 million in the change in cash overdrafts.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily Xeron and PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that the respective subsidiary defaults. None of these

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subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at March 31, 2015 was $31.1 million, with the guarantees expiring on various dates through February 28, 2016.

We issued a letter of credit for $1.0 million, which was renewed through September 12, 2015, related to the electric transmission services for FPU's northwest electric division. We also issued a letter of credit to our current primary insurance company for $1.1 million, which expires on October 31, 2015, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased to $40,000 the letter of credit to our former primary insurance company, which will expire on June 1, 2015. There have been no draws on these letters of credit as of March 31, 2015. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.3 million to TETLP related to the precedent agreement and firm transportation service agreement between our Delaware and Maryland divisions.

Contractual Obligations

There has not been any material change in the contractual obligations presented in our 2014 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 March 31, 2015.

	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]	$30,090	$8,857	$2,856	$ —	$41,803
Forward purchase contracts - Propane [2]	202	—	—	—	202
Total	$30,292	$8,857	$2,856	$ —	$42,005

(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.

Rates and Regulatory Matters

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by the respective state PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At March 31, 2015, we were involved in rate filings and/or regulatory matters in each of the jurisdictions in which we operate. Each of these rate filings and/or regulatory matters is 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.

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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 $161.4 million at March 31, 2015, as compared to a fair value of $182.2 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, 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 propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 6.3 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 March 31, 2015 is presented in the following table.

At March 31, 2015	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	420,000	$0.4788	$0.4788
Purchase	421,000	$0.4775	$0.4789

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the second quarter of 2015

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 March 31, 2015 and December 31, 2014, 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)	March 31, 2015	December 31, 2014
Mark-to-market energy assets, including put and call options	$46	$1,055
Mark-to-market energy liabilities, including swap agreements	$20	$1,018

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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 March 31, 2015. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2015.

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2015, 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, 2014, 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 Report. 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]
January 1, 2015 through January 31, 2015 [1]	317	$48.82	—	—
February 1, 2015 through February 28, 2015	—	$—	—	—
March 1, 2015 through March 31, 2015	—	$—	—	—
Total	317	$48.82	—	—

(1) Chesapeake 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, 2014. During the quarter ended March 31, 2015, 317 shares were purchased through the reinvestment of dividends on deferred stock units.

(2) Except for the purposes described in Footnote [1], Chesapeake has no publicly announced plans or programs to repurchase its shares.

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

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Item 6. Exhibits

31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated May 6, 2015.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated May 6, 2015.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 6, 2015.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 6, 2015.
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: May 6, 2015