CHESAPEAKE UTILITIES CORP
Form 10-Q
November 05, 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: September 30, 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 — 15,268,158 shares outstanding as of October 31, 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 wholly-owned subsidiary of Chesapeake into which Gatherco, Inc. merged on April 1, 2015
BravePoint: BravePoint, Inc., our former advanced information services subsidiary, headquartered in Norcross, Georgia, which was sold on October 1, 2014
CDD: Cooling degree-day, which is the measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit
Chesapeake: 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
Credit Agreement: An agreement between Chesapeake, PNC and other participating lenders related to our unsecured revolving credit facility
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 United States government that regulates the interstate transmission of electricity, natural gas, and oil
FDEP: Florida Department of Environmental Protection
FDOT: Florida Department of Transportation
FGT: Florida Gas Transmission Company
FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake
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
FRP: Fuel Retention Percentage
GAAP: Accounting principles generally accepted in the United States of America
Gatherco: Gatherco, Inc.
GRIP: Gas Reliability Infrastructure Program is a natural gas pipeline replacement program in Florida, pursuant to which we collect a surcharge from certain of our Florida customers to recover capital and other program-related costs associated with the replacement of qualifying distribution mains and services in Florida
Gulf Power: Gulf Power Company
Gulfstream: Gulfstream Natural Gas System, LLC
HDD: Heating degree-day, which is a measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is below 65 degrees Fahrenheit
JEA: The community-owned utility located in Jacksonville, Florida, formerly known as Jacksonville Electric Authority
Lenders: Participating lenders, including PNC, which have committed funds to our Revolver
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 were 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
PNC: PNC Bank, National Association, the administrative agent and primary lender for our Revolver
Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the Shelf Agreement for the future purchase of our Shelf Notes
PSC: Public Service Commission, which is the state agency that regulates the rates and services provided by Chesapeake’s natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida
RAP: Remedial Action Plan, which is a plan that outlines the procedures taken or being considered in removing contaminants from a MGP formerly owned by Chesapeake or FPU
Revolver: The unsecured revolving credit facility issued to us by the Lenders, including PNC as the primary lender
Sandpiper: Sandpiper Energy, Inc.

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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
Shelf Agreement: An agreement entered into by Chesapeake and Prudential related to the purchase of the Shelf Notes
Shelf Notes: Unsecured senior promissory notes that we may request Prudential to purchase under the Shelf Agreement
SICP: 2013 Stock and Incentive Compensation Plan
SIR: A system improvement rate adder designed to fund system expansion costs within the city limits of Ocean City, Maryland
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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated Energy	$63,796	$59,356	$235,438	$223,168
Unregulated Energy and other	28,117	32,263	119,238	155,286
Total Operating Revenues	91,913	91,619	354,676	378,454
Operating Expenses				
Regulated Energy cost of sales	23,161	23,040	101,414	102,020
Unregulated Energy and other cost of sales	17,959	22,935	73,465	112,702
Operations	26,388	25,365	79,522	76,604
Maintenance	2,603	2,562	8,033	7,168
Gain from a settlement	—	—	(1,500)	—
Depreciation and amortization	7,636	6,774	22,155	20,146
Other taxes	3,257	3,151	10,000	9,942
Total Operating Expenses	81,004	83,827	293,089	328,582
Operating Income	10,909	7,792	61,587	49,872
Other income (loss), net of other expenses	36	(32)	(3)	380
Interest charges	2,492	2,495	7,425	6,954
Income Before Income Taxes	8,453	5,265	54,159	43,298
Income taxes	3,334	2,085	21,638	17,303
Net Income	$5,119	$3,180	$32,521	$25,995
Weighted Average Common Shares Outstanding:				
Basic	15,258,819	14,574,678	15,035,569	14,539,841
Diluted	15,306,843	14,616,665	15,083,641	14,588,130
Earnings Per Share of Common Stock:				
Basic	$0.34	$0.22	$2.16	$1.79
Diluted	$0.33	$0.22	$2.16	$1.78
Cash Dividends Declared Per Share of Common Stock	$0.2875	$0.2700	$0.8450	$0.7967

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
(in thousands)				
Net Income	$5,119	$3,180	$32,521	$25,995
Other Comprehensive Income (Loss), net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of $(7), $(5), $(20) and $(18), respectively	(10)	(9)	(30)	(26)
Net gain, net of tax of $62, $26, $187 and $80, respectively	93	39	278	118
Cash Flow Hedges, net of tax:				
Unrealized loss on commodity contract cash flow hedges, net of tax of $(51), $(18), $(29) and $(19), respectively	(75)	(27)	(43)	(28)
Total Other Comprehensive Income	8	3	205	64
Comprehensive Income	$5,127	$3,183	$32,726	$26,059

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	September 30, 2015	December 31, 2014
(in thousands, except shares)		
Property, Plant and Equipment		
Regulated Energy	$813,145	$766,855
Unregulated Energy	141,393	84,773
Other businesses and eliminations	19,190	18,497
Total property, plant and equipment	973,728	870,125
Less: Accumulated depreciation and amortization	(210,979)	(193,369)
Plus: Construction work in progress	56,441	13,006
Net property, plant and equipment	819,190	689,762
Current Assets		
Cash and cash equivalents	3,781	4,574
Accounts receivable (less allowance for uncollectible accounts of $1,088 and $1,120, respectively)	39,861	53,300
Accrued revenue	8,797	13,617
Propane inventory, at average cost	4,211	7,250
Other inventory, at average cost	4,143	3,699
Regulatory assets	7,653	8,967
Storage gas prepayments	3,839	4,258
Income taxes receivable	6,935	18,806
Deferred income taxes	338	—
Prepaid expenses	7,507	6,652
Mark-to-market energy assets	286	1,055
Other current assets	339	195
Total current assets	87,690	122,373
Deferred Charges and Other Assets		
Goodwill	16,048	4,952
Other intangible assets, net	2,317	2,404
Investments, at fair value	3,412	3,678
Regulatory assets	77,332	78,136
Receivables and other deferred charges	2,453	3,164
Total deferred charges and other assets	101,562	92,334
Total Assets	$1,008,442	$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	September 30, 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)	$7,429	$7,100
Additional paid-in capital	189,321	156,581
Retained earnings	162,036	142,317
Accumulated other comprehensive loss	(5,471)	(5,676)
Deferred compensation obligation	1,863	1,258
Treasury stock	(1,863)	(1,258)
Total stockholders’ equity	353,315	300,322
Long-term debt, net of current maturities	155,909	158,486
Total capitalization	509,224	458,808
Current Liabilities		
Current portion of long-term debt	9,139	9,109
Short-term borrowing	127,093	88,231
Accounts payable	41,129	44,610
Customer deposits and refunds	24,020	25,197
Accrued interest	3,242	1,352
Dividends payable	4,388	3,939
Deferred income taxes	—	832
Accrued compensation	8,909	10,076
Regulatory liabilities	9,346	3,268
Mark-to-market energy liabilities	154	1,018
Other accrued liabilities	9,443	6,603
Total current liabilities	236,863	194,235
Deferred Credits and Other Liabilities		
Deferred income taxes	174,247	160,232
Regulatory liabilities	43,356	43,419
Environmental liabilities	9,003	8,923
Other pension and benefit costs	32,619	35,027
Deferred investment tax credits and other liabilities	3,130	3,825
Total deferred credits and other liabilities	262,355	251,426
Other commitments and contingencies (Note 6)		
Total Capitalization and Liabilities	$1,008,442	$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)

	Nine Months Ended September 30,	
	2015	2014
(in thousands)		
Operating Activities		
Net income	$32,521	$25,995
Adjustments to reconcile net income to net operating cash:		
Depreciation and amortization	22,155	20,146
Depreciation and accretion included in other costs	5,280	5,152
Deferred income taxes, net	(1,155)	(156)
Realized gain on commodity contracts/sale of assets/investments	(411)	(436)
Unrealized loss (gain) on investments/commodity contracts	60	(44)
Employee benefits and compensation	901	476
Share-based compensation	1,445	1,519
Other, net	13	2
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	21,898	38,304
Propane inventory, storage gas and other inventory	3,166	4,137
Regulatory assets/liabilities, net	6,467	(8,865)
Prepaid expenses and other current assets	(159)	(804)
Accounts payable and other accrued liabilities	(5,145)	(18,704)
Income taxes receivable/payable	14,883	510
Customer deposits and refunds	(1,177)	(1,169)
Accrued compensation	(1,406)	(1,242)
Other assets and liabilities, net	(652)	198
Net cash provided by operating activities	98,684	65,019
Investing Activities		
Property, plant and equipment expenditures	(102,051)	(69,111)
Proceeds from sales of assets	109	505
Acquisitions, net of cash acquired	(20,930)	—
Environmental expenditures	(113)	(134)
Net cash used in investing activities	(122,985)	(68,740)
Financing Activities		
Common stock dividends	(11,725)	(10,879)
Issuance of stock for Dividend Reinvestment Plan	633	300
Change in cash overdrafts due to outstanding checks	2,964	(503)
Net borrowing (repayment) under line of credit agreements	35,898	(33,994)
Proceeds from issuance of long-term debt	—	49,975
Repayment of long-term debt and capital lease obligation	(4,262)	(2,249)
Net cash provided by financing activities	23,508	2,650
Net Decrease in Cash and Cash Equivalents	(793)	(1,071)
Cash and Cash Equivalents—Beginning of Period	4,574	3,356
Cash and Cash Equivalents—End of Period	$3,781	$2,285

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 ($1.0667 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	—	—	—	32,521	—	—	—	32,521
Other comprehensive income	—	—	—	—	205	—	—	205
Dividend declared ($0.8450 per share)	—	—	—	(12,802)	—	—	—	(12,802)
Retirement savings plan and dividend reinvestment plan	36,289	18	1,849	—	—	—	—	1,867
Common stock issued in acquisition	592,970	289	29,876	—	—	—	—	30,165
Share-based compensation and tax benefit [(3)]	45,703	22	1,015	—	—	—	—	1,037
Treasury stock activities	—	—	—	—	—	605	(605)	—
Balance at September 30, 2015	15,263,673	$7,429	$189,321	$162,036	$ (5,471)	$ 1,863	$(1,863)	$353,315

(1) Includes 70,253 and 57,382 shares at September 30, 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 nine months ended September 30, 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 statements of income for the three and nine months ended September 30, 2014 and condensed consolidated statements of cash flows for the nine months ended September 30, 2014 to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Gain Contingency

Effective May 29, 2015, we entered into a settlement agreement with a vendor related to the implementation of a customer billing system. Pursuant to the agreement, we received $1.5 million in cash, which is reflected as "Gain from a settlement" in the accompanying condensed consolidated statements of income. Previously, at December 31, 2014, we recorded a $6.5 million pretax, non-cash impairment loss related to the same billing system implementation. We may also receive $750,000 in additional cash and discounts on future services; however, the receipt or retention of additional cash and future discounts is contingent upon engaging this vendor to provide agreed-upon services over the next five years.

Subsequent Events

On October 8, 2015, we entered into the Shelf Agreement with Prudential. See Note 14, Long-Term Debt for further details. On the same date, we also entered into the Credit Agreement with the Lenders for a $150.0 million Revolver for a term of five years. On October 19, 2015, we borrowed $25.0 million under the Revolver. See Note 15, Short-Term Borrowing for further details.

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Standards Yet to be Adopted

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

Interest - Imputation of Interest (ASC 835-30) - In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. This standard requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of a debt discount. ASU 2015-03 is effective for our interim and annual financial statements issued beginning January 1, 2016. Early adoption is permitted for financial statements that have not been previously issued. As of September 30, 2015, we had $312,000 of unamortized

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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.
Debt Issuance Costs (ASC 835-30) - In August 2015, the FASB issued ASU 2015-15, Simplifying the Presentation of Debt Issuance Costs Associated with Line-of-Credit Arrangements. This standard clarifies treatment of debt issuance costs associated with line-of-credit arrangements which were not specifically addressed in ASU 2015-03. Issuance costs incurred in connection with line-of-credit arrangements may be treated as an asset and amortized over the term of the line-of-credit arrangement. ASU 2015-15 is effective for our interim and annual financial statements issued beginning January 1, 2016. Early adoption is permitted for financial statements that have not been previously issued. This standard is not expected to have a material impact on our financial position and results of operation.
Business Combinations (ASC 805) - In September 2015, the FASB issued ASU 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. The standard eliminates the requirement to restate prior period financial statements for measurement period adjustments. The new guidance requires that the cumulative impact of a measurement period adjustment (including the impact of prior periods) be recognized in the reporting period in which the adjustment is identified. ASU 2015-16 will be effective for our interim and annual financial statements issued beginning January 1, 2016 and is to be adopted on a prospective basis. Early adoption is permitted for financial statements that have not been previously issued. We are assessing the impact this standard may have on our financial position and results of operation.

2. Calculation of Earnings Per Share

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	$5,119	$3,180	$32,521	$25,995
Weighted average shares outstanding	15,258,819	14,574,678	15,035,569	14,539,841
Basic Earnings Per Share	$0.34	$0.22	$2.16	$1.79
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	$5,119	$3,180	$32,521	$25,995
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	15,258,819	14,574,678	15,035,569	14,539,841
Effect of dilutive securities:				
Share-based compensation	48,024	41,987	48,072	48,289
Adjusted denominator—Diluted	15,306,843	14,616,665	15,083,641	14,588,130
Diluted Earnings Per Share	$0.33	$0.22	$2.16	$1.78

3. Acquisitions
Gatherco Acquisition
On April 1, 2015, we completed the merger with Gatherco, in which Gatherco merged with and into Aspire Energy of Ohio, a newly formed, wholly-owned subsidiary of Chesapeake. As a result, Aspire Energy of Ohio provides natural gas midstream services, including natural gas gathering services and natural gas liquid processing services to over 300 producers, through 16 gathering systems and over 2,000 miles of pipelines in Central and Eastern Ohio. Aspire Energy of Ohio also supplies natural gas to Columbia Gas of Ohio, regional marketers of natural gas, and over 6,000 customers in Ohio through the Consumers Gas Cooperative, an independent entity, which Aspire Energy of Ohio

manages under an operating agreement.

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

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

The merger agreement provides for additional contingent cash consideration to Gatherco's shareholders of up to $15.0 million based on a percentage of revenue generated from potential new gathering opportunities over the next five years.

We incurred $1.3 million in transaction costs associated with this merger, $514,000 of which was expensed in the nine months ended September 30, 2015. Transactions costs are included in operations expense in the accompanying condensed consolidated statements of income. The revenue and net income from this acquisition for the three months ended September 30, 2015, included in our condensed consolidated statement of income, were $5.7 million and $55,000, respectively. The revenue and net loss from this acquisition for the nine months ended September 30, 2015, included in our condensed consolidated statement of income, were $11.0 million and $133,000, respectively. The financial 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 produced a significant portion of Gatherco's annual earnings. This acquisition is expected to be accretive to our earnings in the first full year of operations, which will include the first quarter of 2016.

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

(in thousands)	
Purchase price	$57,658
Property plant and equipment	52,578
Cash	6,806
Accounts receivable	3,629
Income taxes receivable	3,012
Other assets	247
Total assets acquired	66,272
Long-term debt	1,696
Deferred income taxes	13,863
Accounts payable	3,837
Other current liabilities	314
Total liabilities assumed	19,710
Net identifiable assets acquired	46,562
Goodwill	$11,096

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

The initial accounting for the Gatherco acquisition is not complete because the valuation necessary to assess the fair values of property, plant and equipment and the related impact on deferred income tax amounts is considered preliminary as we continue to evaluate these assets. The valuation of additional contingent cash consideration and potential

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environmental remediation costs may be adjusted as additional information becomes available. Although the purchase price allocation can be modified up to one year from the date of the acquisition, we intend to finalize the allocation as soon as practicable.

Other acquisitions

On May 7, 2015, we purchased certain propane distribution assets used to serve 253 customers in Citrus County, Florida for approximately $242,000. In connection with this acquisition, we recorded $186,000 in intangible assets related to a non-compete agreement and the customer list to be amortized over six and 10 years, respectively. The remaining purchase price was allocated to property, plant and equipment and accounts receivable. The revenue and net income from this acquisition that were included in our condensed consolidated statements of income for the three and nine months ended September 30, 2015 were not material.

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 nine months of 2015.

Maryland

Ocean City SIR Filing: On July 2, 2015, Sandpiper filed an application with the Maryland PSC, to establish an SIR to further fund system expansion within the city limits of Ocean City, Maryland. The proposed SIR, which would only be charged to customers located within city limits, was supported by Ocean City's local government. On August 5, 2015, the Maryland PSC approved the application.

Florida

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

On July 1, 2015, FPU's electric division filed an electric depreciation study with the Florida PSC. Depending upon the Florida PSC’s decision in this proceeding, depreciation expense may change for FPU’s electric division as a result of a change in depreciation rates effective January 1, 2015. This action is scheduled for review by the Florida PSC at its Agenda Conference to be held in December 2015.

On September 1, 2015, FPU’s electric division filed to recover the cost of the proposed Florida Power & Light Company interconnect project through the annual Fuel and Purchased Power Cost Recovery Clause filing. The project will enable FPU's electric division to negotiate a new power purchase agreement that will mitigate fuel costs for its Northeast Division. The hearing on this Docket was held on November 4, 2015. Ruling by the Florida PSC on the docket is expected at the Agenda Conference to be held in December 2015.

Eastern Shore

White Oak Mainline Expansion Project: On November 21, 2014, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate certain expansion facilities designed to provide 45,000 Dts/d of firm transportation service to an industrial customer in Kent County, Delaware. Eastern Shore proposes to construct approximately 7.2 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and 3,550 horsepower of additional compression at Eastern Shore’s existing Delaware City Compressor Station in New Castle County, Delaware. The estimated cost of the project is $29.8 million. On January 22, 2015, the FERC issued a Notice of Intent to Prepare an Environmental Assessment for this project. In February, April and May 2015, Eastern Shore filed environmental data in response to comments regarding evaluation of alternate routes for a segment of the pipeline route in the vicinity of the Kemblesville Historic District. On June 2, 2015, a field meeting was conducted to review the proposed route and alternate routes. In response to comments received from the National Park Service and other stakeholders, FERC Staff requested

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that Eastern Shore conduct an additional investigation in relation to Eastern Shore's existing right-of-way. On July 9, 2015, FERC issued a 30-day public scoping notice in advance of issuing an Environmental Assessment in order to solicit comments from the public regarding construction of the Kemblesville loop. On August 18, 2015, Eastern Shore submitted supplemental information to the FERC regarding the results of its investigation of the Kemblesville loop.

System Reliability Project: On May 22, 2015, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore’s customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days in 2014 and 2015. The estimated cost of the project is $32.1 million. Since the project is intended to improve system reliability, Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project, and an order granting the requested authorization by December 2015.

On June 8, 2015, the FERC filed a notice of the application, and the comment period ended on June 29, 2015. Eastern Shore anticipates FERC approval of this project in the fourth quarter of 2015 and estimates that construction will start in the first quarter of 2016.

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

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 September 30, 2015, we had approximately $10.0 million in environmental liabilities, representing our estimate of the future costs associated with all of FPU’s MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to all of its MGP sites, approximately $10.0 million of which has been recovered as of September 30, 2015, leaving approximately $4.0 million in regulatory assets for future recovery of environmental costs from FPU’s customers.

In addition to the FPU MGP sites, we had $389,000 in environmental liabilities at September 30, 2015 related to Chesapeake’s MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of September 30, 2015, we had approximately $116,000 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 Delaware PSC approval for recovery. As of September 30, 2015, we had approximately $239,000 in environmental liabilities and $273,000 in regulatory and other assets related to this site.

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

West Palm Beach, Florida

We are evaluating remedial options 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.

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FPU is implementing a remedial plan approved by the FDEP for the east parcel of the West Palm Beach site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. We anticipate 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 September 30, 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 September 30, 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 September 30, 2015.

Key West, Florida

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

In October 2012, FDEP issued a RAP approval order, which requires a limited semi-annual monitoring program. The most recent groundwater-monitoring event was conducted on September 14, 2015. Natural Attenuation Default criteria were met at all locations sampled. The next semi-annual sampling event is scheduled for March 2016. Although the duration of the FDEP-required limited NAM cannot be determined with certainty, we anticipate that total costs to complete the remedial action will not exceed $50,000. The annual cost to conduct the limited NAM program is not expected to exceed $8,000.

Pensacola, Florida

FPU formerly owned and operated a MGP in Pensacola, Florida, which was subsequently owned by Gulf Power. Portions of the site are now owned by the City of Pensacola and the FDOT. In October 2009, FDEP informed Gulf Power that it would approve a conditional No Further Action determination for the site with the requirement for institutional and engineering controls. On June 16, 2014, FDEP issued a draft memorandum of understanding between FDOT and FDEP

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to implement site closure with approved institutional and engineering controls for the site. We anticipate that FPU's share of remaining legal and cleanup costs will not exceed $5,000.

Winter Haven, Florida

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

Groundwater monitoring results on the southern portion of this site indicate that natural attenuation default criteria continue to be exceeded. Plans to modify the monitoring network on the southern portion of the site in order to collect additional data to support the development of a remedial plan were specified in a letter to FDEP, dated October 17, 2014. The well installation and abandonment program was implemented in October 2014, and documentation was reported in the semi-annual RAP implementation status report submitted on 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; therefore, we have not recorded a liability for sediment remediation.

Salisbury, Maryland

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

Seaford, Delaware

In a letter dated December 5, 2013, the DNREC notified us that it would be conducting a facility evaluation of a former MGP site in Seaford, Delaware. In a report issued in January 2015, DNREC provided the evaluation, which found several compounds within the groundwater and soil that require further investigation. We submitted an application to the DNREC on April 2, 2015, which was approved on September 17, 2015, 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 between $273,000 and $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.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with EGWIC to purchase propane over a six-year term. Approximately three years, four months 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.

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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 2015, PESCO renewed contracts to purchase natural gas from various suppliers. The total monthly purchase commitment ranges from 9,982 to 13,423 Dts/d from June 2015 to May 2016. These contracts expire in May 2016.

FPU's electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with JEA requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) a fixed charge coverage ratio greater than 1.5 times. If FPU fails to comply with either of these ratios, it has 30 days to cure the default or, if the default is not cured, to provide an irrevocable letter of credit. FPU's electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet either of these ratios, it has to provide the supplier a written explanation of actions taken, or proposed to be taken, to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could also result in FPU having to provide an irrevocable letter of credit. As of September 30, 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 September 30, 2015 was $36.1 million, with the guarantees expiring on various dates through September 22, 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, 2016, 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 $1.2 million which expires on October 31, 2016, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company, we renewed and decreased the letter of credit for $24,000 to our former primary insurance company, which will expire on June 1, 2016. We have also issued a letter of credit of $1.0 million which expires on March 31, 2016, related to PESCO's transactions at the Natural Gas Exchange, Inc.

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

There have been no draws on these letters of credit as of September 30, 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.

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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 September 30, 2015, we maintained a liability of $100,000 related to unrecognized income tax benefits and $404,000 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. Effective April 1, 2015, this segment includes Aspire Energy of Ohio, whose services include natural gas gathering and processing (See Note 3, Acquisitions, regarding the acquisition of Gatherco). Also included in this segment are other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

We had previously identified "Other" as a separate reportable segment, which consisted primarily of our 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy segment	$63,526	$59,086	$234,608	$222,308
Unregulated Energy segment	28,387	27,041	120,068	141,215
Other businesses	—	5,492	—	14,931
Total operating revenues, unaffiliated customers	$91,913	$91,619	$354,676	$378,454
Intersegment Revenues [1]				
Regulated Energy segment	$270	$270	$830	$860
Unregulated Energy segment	1,222	30	3,095	150
Other businesses	220	258	660	760
Total intersegment revenues	$1,712	$558	$4,585	$1,770
Operating Income (Loss)				
Regulated Energy segment	$11,828	$9,202	$47,616	$41,004
Unregulated Energy segment	(1,022)	(1,972)	13,666	8,843
Other businesses and eliminations	103	562	305	25
Total operating income	10,909	7,792	61,587	49,872
Other income (loss), net of other expenses	36	(32)	(3)	380
Interest	2,492	2,495	7,425	6,954
Income before Income Taxes	8,453	5,265	54,159	43,298
Income taxes	3,334	2,085	21,638	17,303
Net Income	$5,119	$3,180	$32,521	$25,995

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

(in thousands)	September 30, 2015	December 31, 2014
Identifiable Assets		
Regulated Energy segment	$824,330	$796,021
Unregulated Energy segment	156,838	84,732
Other businesses and eliminations	27,274	23,716
Total identifiable assets	$1,008,442	$904,469

Our operations are entirely domestic.

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8. Accumulated Other Comprehensive 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 loss. The following tables present the changes in the balance of accumulated other comprehensive loss for the nine months ended September 30, 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	—	(76)	(76)
Amounts reclassified from accumulated other comprehensive loss	248	33	281
Net current-period other comprehensive income	248	(43)	205
As of September 30, 2015	$(5,395)	$(76)	$(5,471)

(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	—	(28)	(28)
Amounts reclassified from accumulated other comprehensive loss	92	—	92
Net current-period other comprehensive income (loss)	92	(28)	64
As of September 30, 2014	$(2,441)	$(28)	$(2,469)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and nine months ended September 30, 2015 and 2014. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
(in thousands)				
Amortization of defined benefit pension and postretirement plan items:				
Prior service cost [1]	$17	$14	$50	$44
Net gain [1]	(155)	(65)	(465)	(198)
Total before income taxes	(138)	(51)	(415)	(154)
Income tax benefit	55	21	167	62
Net of tax	$(83)	$(30)	$(248)	$(92)
Gains and losses on commodity contracts cash flow hedges				
Propane swap agreements [2]	$—	$—	$—	$—
Call options [2]	—	—	(55)	—
Total before income taxes	—	—	(55)	—
Income tax benefit	—	—	22	—
Net of tax	—	—	(33)	—
Total reclassifications for the period	$(83)	$(30)	$(281)	$(92)

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

9. Employee Benefit Plans
Net periodic benefit costs for our pension and post-retirement benefits plans for the three and nine months ended September 30, 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 September 30,	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	91	37	114	—	25	12	17	16	2	—
Net periodic cost (benefit)	58	11	(37)	(126)	50	40	9	10	17	17
Amortization of pre-merger regulatory asset	—	—	191	191	—	—	—	—	2	2
Total periodic cost	$58	$11	$154	$65	$50	$40	$9	$10	$19	$19

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For the Nine Months Ended September 30, (in thousands)	Chesapeake Pension Plan 2015	Chesapeake Pension Plan 2014	FPU Pension Plan 2015	FPU Pension Plan 2014	Chesapeake SERP 2015	Chesapeake SERP 2014	Chesapeake Postretirement Plan 2015	Chesapeake Postretirement Plan 2014	FPU Medical Plan 2015	FPU Medical Plan 2014
Interest cost	$306	$320	$1,877	$1,941	$68	$69	$33	$39	$45	$50
Expected return on plan assets	(405)	(398)	(2,330)	(2,318)	—	—	—	—	—	—
Amortization of prior service cost	—	—	—	—	8	14	(58)	(58)	—	—
Amortization of net loss	272	112	341	—	74	36	53	50	5	—
Net periodic cost (benefit)	173	34	(112)	(377)	150	119	28	31	50	50
Amortization of pre-merger regulatory asset	—	—	571	571	—	—	—	—	6	6
Total periodic cost	$173	$34	$459	$194	$150	$119	$28	$31	$56	$56

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 FPU merger in 2009. This was deferred as a regulatory asset by FPU prior to the merger, to be recovered through rates pursuant to a previous order by the Florida PSC. The unamortized balance of this regulatory asset was $3.1 million and $3.6 million at September 30, 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 FPU 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 loss. The following table presents the amounts included in the regulatory asset and accumulated other comprehensive loss that were recognized as components of net periodic benefit cost during the three and nine months ended September 30, 2015 and 2014:

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

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For the Nine Months Ended September 30, 2015	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 8	$ (58)	$—	$(50)
Net loss	272	341	74	53	5	745
Total recognized in net periodic benefit cost	$ 272	$341	$ 82	$ (5)	$5	$695
Recognized from accumulated other comprehensive loss (1)	$ 272	$65	$ 82	$ (5)	$1	$415
Recognized from regulatory asset	—	276	—	—	4	280
Total	$ 272	$341	$ 82	$ (5)	$5	$695

For the Three Months Ended September 30, 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	16	—	65
Total recognized in net periodic benefit cost	$ 37	$—	$ 17	$ (3)	$—	$51
Recognized from accumulated other comprehensive loss (1)	$ 37	$—	$ 17	$ (3)	$—	$51
Recognized from regulatory asset	—	—	—	—	—	—
Total	$ 37	$—	$ 17	$ (3)	$—	$51

For the Nine Months Ended September 30, 2014	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service cost (credit)	$ —	$—	$ 14	$ (58)	$—	$(44)
Net loss	112	—	36	50	—	198
Total recognized in net periodic benefit cost	$ 112	$—	$ 50	$ (8)	$—	$154
Recognized from accumulated other comprehensive loss (1)	$ 112	$—	$ 50	$ (8)	$—	$154
Recognized from regulatory asset	—	—	—	—	—	—
Total	$ 112	$—	$ 50	$ (8)	$—	$154

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

During the three and nine months ended September 30, 2015, we contributed $127,000 and $346,000, respectively, to the Chesapeake Pension Plan and $402,000 and $1.1 million, respectively, 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 annual contribution payments required.

The Chesapeake SERP, the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake SERP for the three and nine months ended September 30, 2015, were $38,000 and $109,000, respectively. We expect to pay total cash benefits of approximately $151,000 under the Chesapeake Pension SERP in 2015. Cash benefits paid under the Chesapeake Postretirement Plan, primarily for medical claims for the three and nine months ended September 30, 2015, were

$14,000 and $42,000, respectively. We estimate that approximately $79,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2015. Cash benefits paid under the FPU Medical Plan, primarily for medical claims for the three and nine months ended September 30, 2015, were $47,000 and $163,000, respectively. We estimate that approximately $207,000 will be paid for such benefits under the FPU Medical Plan in 2015.

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10. Investments

The investment balances at September 30, 2015 and December 31, 2014, consisted of the following:

(in thousands)	September 30, 2015	December 31, 2014
Rabbi trust (associated with the Deferred Compensation Plan)	$3,394	$3,678
Investments in equity securities	18	—
Total	$3,412	$3,678

We classify these investments as trading securities and report them at their fair value. For the three months ended September 30, 2015 and 2014, we recorded a net unrealized gain of $238,000 and $41,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the nine months ended September 30, 2015 and 2014, we recorded a net unrealized loss of $131,000 and a net unrealized gain of $111,000, respectively, in other income in the condensed consolidated statements of income related to these investments. For the investment in the Rabbi Trust, we also have recorded an associated liability, which is included in other pension and benefit costs in the condensed consolidated balance sheets and is adjusted each month for the gains and losses incurred by the Rabbi Trust.

11. Share-Based Compensation

Our non-employee directors and key employees are granted share-based awards through the 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 grant date and the number of shares to be issued at the end of the service period.

The table below presents the amounts included in net income related to share-based compensation expense for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
(in thousands)				
Awards to non-employee directors	$165	$137	$475	$394
Awards to key employees	334	317	970	1,125
Total compensation expense	499	454	1,445	1,519
Less: tax benefit	(201)	(183)	(582)	(612)
Share-based compensation amounts included in net income	$298	$271	$863	$907

Non-employee Directors

Shares granted to non-employee directors are issued in advance of the directors' service periods and are fully vested as of the grant date. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2015, each of our non-employee directors received an annual retainer of 1,207 shares of common stock under the SICP for Board service through the 2016 Annual Meeting of Stockholders. A summary of the stock activity for our non-employee directors during the nine months ended September 30, 2015 is presented below:

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	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2014	—	$—
Granted	14,484	$45.54
Vested	(14,484)	$45.54
Outstanding— September 30, 2015	—	$—

At September 30, 2015, there was $385,000 of unrecognized compensation expense related to these awards. This expense will be recognized over the directors' remaining service periods ending April 30, 2016.

Key Employees

The table below presents the summary of the stock activity for awards to key employees for the nine months ended September 30, 2015:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2014	123,038	$32.60
Granted	33,719	$48.21
Vested	(43,839)	$28.01
Expired	(2,520)	$28.83
Outstanding— September 30, 2015	110,398	$38.34

In January and March 2015, our Board of Directors granted awards of 33,719 shares of common stock to key employees under the SICP. The shares granted in January and March 2015 are multi-year awards that will vest at the end of the three-year service period ending December 31, 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 grant date of each award. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

At September 30, 2015, the aggregate intrinsic value of the SICP awards granted to key employees was $5.9 million. At September 30, 2015, there was $1.7 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 September 30, 2015, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2015

In March, May and June 2015, Sharp paid a total of $143,000 to purchase put options to protect against a decline in propane prices and related potential inventory losses associated with 2.5 million gallons for the propane price cap program in the upcoming heating season. The put options are exercised if propane prices fall below the strike prices of $0.4950, $0.4888 and $0.4500 per gallon in December 2015 through February 2016 and $0.4200 per gallon in January through March 2016. If exercised, we will receive the difference between the market price and the strike price during those months. We accounted for the put options as fair value hedges, and there is no ineffective portion of these hedges. As of September 30, 2015, the put options had a fair value of $64,000. The change in fair value of the put options effectively reduced our propane inventory balance.

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In March, May and June 2015, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 2.5 million gallons expected to be purchased for the upcoming heating season. Under these swap agreements, Sharp receives the difference between the index prices (Mont Belvieu prices in December 2015 through March 2016) and the swap prices of $0.5950, $0.5888, $0.5500 and $0.5200 per gallon for each swap agreement, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap prices, Sharp will pay the difference. These swap agreements essentially fix the price of the 2.5 million gallons that we expect to purchase for the upcoming heating season. We accounted for the swap agreements as cash flow hedges, and there is no ineffective portion of these hedges. At September 30, 2015, the swap agreements had a liability fair value of $128,000. The change in the fair value of the swap agreements 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 purchased at market-based prices to supply the demands of our propane price cap program customers. The retail price that we charged to those customers during the heating season was capped at a pre-determined level. We would have exercised the call options if the propane prices had risen above the strike price of $1.0875 per gallon in December 2014 through February of 2015, and $1.0650 per gallon in January through March 2015. 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 purchased in December 2014 through February 2015. Under these swap agreements, Sharp would have received the difference between the index prices (Mont Belvieu prices in December 2014 through February 2015) and the swap prices of $1.1350, $1.0975 and $1.0475 per gallon for each swap agreement, to the extent the index prices exceeded the swap prices. If the index prices were lower than the swap prices, Sharp would pay the difference. These swap agreements essentially fixed the price of the 630,000 gallons purchased during this period. We had initially accounted for them as cash flow hedges as the swap agreements met all the requirements. We paid $1.1 million, representing the difference between the market prices and strike prices during those months for the swap agreements. At December 31, 2014, we elected to discontinue hedge accounting on the swap agreements and reclassified $735,000 of unrealized loss from other comprehensive loss to propane cost of sales. Subsequently, we accounted for them as derivative instruments on a mark-to-market basis with the change in 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 for the propane price cap program in December 2014 through February 2015. We exercised the put options because the propane prices fell below the strike prices of $1.0350, $0.9975, and $0.9475 per gallon, for each option agreement in December 2014 through February 2015, respectively. We paid $128,000 to purchase the put options and received $868,000, 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 statements of income for the period of change. As of September 30, 2015, we had the following outstanding trading contracts, which we accounted for as derivatives:

At September 30, 2015	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	2,940,000	$0.4750 - $0.5288	$0.5210
Purchase	2,940,000	$0.4350 - $0.5025	$0.4545

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the fourth 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 September 30, 2015, Xeron had no accounts receivable or accounts payable balances to offset with these two

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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 September 30, 2015 and December 31, 2014, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	September 30, 2015	December 31, 2014
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	$222	$407
Derivatives designated as fair value hedges			
Put options	Mark-to-market energy assets	64	622
Derivatives designated as cash flow hedges			
Call options	Mark-to-market energy assets	—	26
Total asset derivatives		$286	$1,055

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	September 30, 2015	December 31, 2014
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	$26	$283
Propane swap agreements	Mark-to-market energy liabilities	—	735
Derivatives designated as cash flow hedges			
Propane swap agreements	Mark-to-market energy liabilities	128	—
Total liability derivatives		$154	$1,018

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

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(in thousands)	(Loss) on Derivatives	2015	2014	2015	2014
Derivatives not designated as hedging instruments					
Realized gain on forward contracts [1]	Revenue	$187	$54	$393	$1,384
Unrealized gain (loss) on forward contracts [1]	Revenue	(7)	(5)	71	(67)
Call option	Cost of sales	—	—	—	137
Propane swap agreements	Cost of sales	—	—	18	—
Derivatives designated as fair value hedges					
Put options	Cost of sales	—	(43)	506	(92)
Put options [2]	Propane Inventory	(46)	—	(79)	—
Derivatives designated as cash flow hedges					
Propane swap agreements	Other Comprehensive Loss	(126)	(45)	(128)	(46)
Call options	Cost of sales	—	—	(81)	—
Total		$8	$(39)	$700	$1,316

(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 September 30, 2015 and December 31, 2014:

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As of September 30, 2015	Fair Value	Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$18	$18	$—	$—
Investments—guaranteed income fund	$276	$—	$—	$276
Investments—other	$3,118	$3,118	$—	$—
Mark-to-market energy assets, incl. put options and swap agreements	$286	$—	$286	$—
Liabilities:				
Mark-to-market energy liabilities incl. swap agreements	$154	$—	$154	$—

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 September 30, 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 nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,	
	2015	2014
(in thousands)		
Beginning Balance	$287	$458
Purchases and adjustments	(11)	(89)
Transfers	(3)	(58)
Investment income	3	4
Ending Balance	$276	$315

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

At September 30, 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 September 30, 2015, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of $159.9 million. This compares to a fair value of $175.8 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, 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)	September 30, 2015	December 31, 2014
FPU secured first mortgage bonds [1] :		
9.08% bond, due June 1, 2022	$7,973	$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	25,500	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	5,155	6,130
Total long-term debt	165,048	167,595
Less: current maturities	(9,139)	(9,109)
Total long-term debt, net of current maturities	$155,909	$158,486

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

Shelf Agreement

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

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

15. Short-Term Borrowing

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

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

October 19, 2015, we borrowed $25.0 million under the Revolver.

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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 recoverable 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 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 of potential downturns in the financial markets, lower discount rates, or costs associated with the Patient Protection and Affordable Care Act on the asset values and resulting higher costs and funding obligations of the Company's pension and other postretirement benefit plans;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the extent of our success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the 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;
- continuing to build a branded culture that drives a shared mission, vision, and values;
- 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.

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.

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

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

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Results of Operations for the Three and Nine Months ended September 30, 2015

Overview and Highlights

Our net income for the quarter ended September 30, 2015 was $5.1 million, or $0.33 per share. This represents an increase of $1.9 million, or $0.11 per share, compared to net income of $3.2 million, or $0.22 per share, as reported for the same quarter in 2014. Increases in operating income from both the Regulated Energy and Unregulated Energy segments were the key drivers in our net income growth.

	Three Months Ended September 30, 2015	2014	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$11,828	$9,202	$2,626
Unregulated Energy segment	(1,022)	(1,972)	950
Other businesses and eliminations	103	562	(459)
Operating Income	$10,909	$7,792	3,117
Other Income (Loss), net of Other Expenses	36	(32)	68
Interest Charges	2,492	2,495	(3)
Pre-tax Income	8,453	5,265	3,188
Income Taxes	3,334	$2,085	1,249
Net Income	$5,119	$3,180	$1,939
Earnings Per Share of Common Stock			
Basic	$0.34	$0.22	$0.12
Diluted	$0.33	$0.22	$0.11

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Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Third Quarter of 2014 Reported Results	$5,265	$3,180	$0.22
Adjusting for Unusual Items:			
Absence of BravePoint, which was sold in October 2014	(454)	(274)	(0.02)
	(454)	(274)	(0.02)
Increased (Decreased) Gross Margins:			
Contribution from Aspire Energy of Ohio	2,037	1,230	0.08
Service expansions (See Major Projects and Initiatives table)	1,708	1,031	0.07
GRIP	1,144	691	0.05
Higher retail propane margins	1,029	621	0.04
Natural gas growth (excluding service expansions)	895	540	0.04
FPU electric base rate increase	673	406	0.03
Natural gas marketing	479	289	0.02
	7,965	4,808	0.33
Increased Other Operating Expenses:			
Expenses from Aspire Energy of Ohio	(1,933)	(1,167)	(0.08)
Higher payroll and benefits costs	(1,098)	(663)	(0.05)
Higher depreciation, asset removal and property tax costs due to recent capital investments	(647)	(391)	(0.03)
Increased accrual for incentive compensation	(314)	(190)	(0.01)
	(3,992)	(2,411)	(0.17)
Interest Charges	3	2	—
Net Other Changes [1]	(334)	(186)	(0.03)
Third Quarter of 2015 Reported Results	$8,453	$5,119	$0.33

[1] The earnings per share impact net of other changes shown above includes $(0.01) of dilution from the issuance of 592,970 shares of our common stock in conjunction with the merger of Gatherco into Aspire Energy of Ohio on April 1, 2015.

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Our net income for the nine months ended September 30, 2015 was $32.5 million, or $2.16 per share. This represents an increase of $6.5 million, or $0.38 per share, compared to net income of $26.0 million, or $1.78 per share, as reported for the same period in 2014. Increases in operating income from both the Regulated Energy and Unregulated Energy segments were the key drivers in our net income growth. Also included in our results for the nine months ended September 30, 2015 was a $902,000 after-tax gain ($1.5 million in operating income), or $0.06 per share, related to cash received from a settlement with a vendor regarding a customer billing system implementation.

	Nine Months Ended September 30,		Increase
	2015	2014	(decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$47,616	$41,004	$6,612
Unregulated Energy segment	13,666	8,843	4,823
Other businesses and eliminations	305	25	280
Operating Income	61,587	49,872	11,715
Other Income (Loss), net of Other Expenses	(3)	380	(383)
Interest Charges	7,425	6,954	471
Pre-tax Income	54,159	43,298	10,861
Income Taxes	21,638	17,303	4,335
Net Income	$32,521	$25,995	$6,526
Earnings Per Share of Common Stock			
Basic	$2.16	$1.79	$0.37
Diluted	$2.16	$1.78	$0.38

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Key variances included:

(in thousands, except per share)	Pre-tax Income	Net Income	Earnings Per Share
Nine months ended September 30, 2014 Reported Results	$43,298	$25,995	$1.78
Adjusting for Unusual Items:			
Gain from a customer billing system settlement	1,500	902	0.06
Gain on sale of business, recorded in 2014	(397)	(238)	(0.02)
Absence of BravePoint, which was sold in October 2014	303	182	0.01
	1,406	846	0.05
Increased (Decreased) Gross Margins:			
Higher retail propane margins	6,742	4,048	0.28
Service expansions (See Major Projects and Initiatives table)	4,085	2,453	0.17
Contribution from Aspire Energy of Ohio	3,661	2,198	0.15
Natural gas growth (excluding service expansions)	3,149	1,891	0.13
GRIP	3,070	1,843	0.13
FPU electric base rate increase	2,366	1,421	0.10
Propane wholesale marketing	(854)	(513)	(0.04)
	22,219	13,341	0.92
Increased Other Operating Expenses:			
Expenses from Aspire Energy of Ohio	(3,828)	(2,298)	(0.16)
Higher payroll and benefits costs	(2,762)	(1,658)	(0.11)
Higher depreciation, asset removal costs and property tax costs due to recent capital investments	(1,700)	(1,021)	(0.07)
Increased accruals for incentive compensation	(1,150)	(690)	(0.05)
Costs associated with a customer billing system settlement and other transactions	(1,081)	(649)	(0.04)
Higher facility maintenance	(729)	(438)	(0.03)
Higher service contractor and other consulting costs	(694)	(417)	(0.03)
Higher amortization expense	(463)	(278)	(0.02)
	(12,407)	(7,449)	(0.51)
Interest Charges	(471)	(283)	(0.02)
Net Other Changes [(1)]	114	71	(0.06)
Nine months ended September 30, 2015 Reported Results	$54,159	$32,521	$2.16

[(1)] The earnings per share impact net of other changes shown above includes $(0.06) of dilution from the issuance of 592,970 shares of our common stock in conjunction with the merger of Gatherco into Aspire Energy of Ohio on April 1, 2015.

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Summary of Key Factors
Major Projects and Initiatives

The following table summarizes gross margin for our existing and future major projects and initiatives (dollars in thousands):

	Gross Margin for the Period							
	Three Months Ended September 30,		Nine Months Ended September 30,		Total 2014	Estimate for		
	2015	2014	2015	2014	Margin	2015	2016	2017
Existing major projects and initiatives	$7,490	$1,928	$17,030	$3,848	$7,114	$25,510	$33,438	$35,295
Future major projects and initiatives	—	—	—	—	—	—	11,200	17,450
	$7,490	$1,928	$17,030	$3,848	$7,114	$25,510	$44,638	$52,745

Existing Major Projects and Initiatives

The following table summarizes our major projects and initiatives commenced since 2014 (dollars in thousands):

	Gross Margin for the Period (1)									
	Three Months Ended September 30,			Nine Months Ended September 30,			Total 2014	Estimate for		
	2015	2014	Variance	2015	2014	Variance	Margin	2015	2016	2017
Acquisition:										
Aspire Energy of Ohio (formerly Gatherco) (2)	$2,037	$—	$2,037	$3,661	$—	$3,661	$—	$7,673	$13,000	$13,000
Natural Gas Transmission Expansions and Contracts:										
Short-term contracts										
New Castle County, Delaware	$507	$657	$(150)	$1,998	$1,256	$742	$2,026	$2,505	$2,029	$1,561
Kent County, Delaware (3)	1,055	—	1,055	1,453	—	1,453	—	1,663	—	—
Total short-term Contracts	1,562	657	905	3,451	1,256	2,195	2,026	4,168	2,029	1,561
Long-term Contracts										
Kent County, Delaware	463	—	463	1,389	—	1,389	463	1,844	1,815	1,789
Polk County, Florida	340	—	340	501	—	501	—	908	1,627	1,627
Total long-term contracts	$803	$—	$803	$1,890	$—	$1,890	$463	$2,752	$3,442	$3,416
Total Expansions & Contracts	$2,365	$657	$1,708	$5,341	$1,256	$4,085	$2,489	$6,920	$5,471	$4,977
Florida GRIP	$2,067	$923	$1,144	$5,314	$2,244	$3,070	$3,356	$7,355	$11,405	$13,756
	$1,021	$348	$673	$2,714	$348	$2,366	$1,269	$3,562	$3,562	$3,562

Florida Electric Rate Case										
Total Major Projects and Initiatives	$7,490	$1,928	$5,562	$17,030	$3,848	$13,182	$7,114	$25,510	$33,438	$35,295

(1) Gross margin of $4.7 million and $16.5 million for the three and nine months ended September 30, 2014, respectively, and $21.8 million for the year ended December 31, 2014, related to projects initiated prior to 2014. These projects were previously disclosed and are excluded from this table as they no longer result in period-over-period variances.
(2) During the three and nine months ended September 30, 2015, we incurred $1.9 million and $3.8 million, respectively, in other operating expenses related to Aspire Energy of Ohio's operation. We expect to incur a total of $6.0 million in other operating expenses in 2015.
(3) The gross margin is attributable to interruptible service Eastern Shore provided to an industrial customer beginning in April 2015. The interruptible service will be replaced by a 20-year OPT ≤ 90 Service beginning in the third quarter of 2016.

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Gatherco Acquisition

On April 1, 2015, we completed the merger with Gatherco, pursuant to which Gatherco merged with and into Aspire Energy of Ohio. Aspire Energy of Ohio provides unregulated natural gas midstream services including natural gas gathering services and natural gas liquid processing services to over 300 producers through 16 gathering systems and over 2,000 miles of pipelines in Central and Eastern Ohio. Aspire Energy of Ohio also supplies natural gas to Columbia Gas of Ohio, regional marketers of natural gas, and over 6,000 customers in Ohio through the Consumers Gas Cooperative, an independent entity, which Aspire Energy of Ohio manages under an operating agreement.

Aspire Energy of Ohio generated $2.0 million in additional gross margin and incurred $1.9 million in other operating expenses for the three months ended September 30, 2015. For the six months following the merger through September 30, 2015, we generated $3.7 million of gross margin and incurred $3.8 million of other operating expenses. 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, which has historically produced a significant portion of Gatherco's annual earnings. This acquisition is expected to be accretive to our earnings in the first full year of operations, which will include the first quarter of 2016.

Service Expansions

During 2014, Eastern Shore, executed a one-year contract with an industrial customer in New Castle County, Delaware to provide 50,000 Dts/d of additional transmission service from April 2014 to April 2015. This contract was subsequently amended to provide 55,580 Dts/d of transmission service at a lower reservation rate through August 2020. The net impact of the contract resulted in a gross margin decline of $150,000 for the quarter ended September 30, 2015. For the nine months ended September 30, 2015, the extension of the contract generated additional gross margin of $509,000, net of the impact of the lower rate, compared to the same period in 2014, and will generate additional gross margin of $334,000 for 2015 compared to 2014.

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. This short-term contract generated additional gross margin of $233,000 for the nine months ended September 30, 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 service generated $463,000 and $1.4 million of gross margin for the three and nine months ended September 30, 2015, respectively. On an annual basis, we expect this service 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.

In April 2015, Eastern Shore commenced interruptible service to the same industrial customer in Kent County, Delaware and generated additional gross margin of $1.1 million and $1.5 million for the three and nine months ended September 30, 2015, respectively. The interruptible service is expected to generate $1.7 million of gross margin in 2015, and it is expected to be replaced by a 20-year OPT ≤ 90 Service beginning in the third quarter of 2016.

On January 16, 2015, the Florida PSC approved a firm transportation agreement between Peninsula Pipeline and our Florida natural gas distribution division. Under this agreement, Peninsula Pipeline provides natural gas transmission service to support our expansion of natural gas distribution service in Polk County, Florida. Peninsula Pipeline began the initial phase of its service to Chesapeake in March 2015, generating $340,000 and $501,000 of additional gross margin for the three and nine months ended September 30, 2015, respectively. This service is expected to generate an estimated annual gross margin of $908,000 in 2015 and, once completed, all phases of this service will generate an estimated annualized gross margin of $1.6 million.

GRIP

GRIP is a natural gas pipe replacement program approved by the Florida PSC, designed to expedite the replacement of qualifying distribution mains and services (any material other than coated steel or plastic) to enhance reliability and integrity of our Florida natural gas distribution systems. This program allows recovery, through regulated rates, of capital and other program-related costs, inclusive of a return on investment, associated with the replacement of the mains and services. Since the program's inception in August 2012, our Florida natural gas distribution operations have invested $69.6 million to replace 153 miles of qualifying distribution mains, $25.5 million of which was invested during the first nine months of 2015. We expect to invest an additional $3.4 million in this program through the end of 2015. The increased investment in GRIP generated additional gross margin of $1.1 million and $3.1 million, for the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014.

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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 $673,000 and $2.4 million in additional gross margin for the three and nine months ended September 30, 2015, respectively.

Future Major Projects and Initiatives
White Oak Mainline Expansion Project: In December 2014, Eastern Shore entered into a precedent agreement with an industrial customer in Kent County, Delaware, to provide a 20-year natural gas transmission service for 45,000 Dts/d for the customer's new facility, upon the satisfaction of certain conditions. This new service will be provided as OPT ≤ 90 Service and is expected to generate at least $5.8 million in annual gross margin. In November 2014, Eastern Shore requested authorization by the FERC to construct 7.2 miles of 16-inch pipeline looping and 3,550 horsepower of new compression in Delaware to provide this service. The estimated cost of these new facilities is approximately $30.0 million. Eastern Shore anticipates service to commence in the third quarter of 2016, following construction of the new facilities. As previously discussed, during the three and nine months ended September 30, 2015, we generated $1.1 million and $1.5 million, respectively, in additional gross margin by providing interruptible service to this customer.
System Reliability Project: On May 22, 2015, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposes to reinforce critical points on its pipeline system. The total project will benefit all of Eastern Shore’s customers by modifying the pipeline system to respond to severe operational conditions experienced during actual winter peak days in 2014 and 2015. Since the project is intended to improve system reliability, Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project and an order granting the requested authorization by December 2015. This project is expected to be in service by late third quarter of 2016 and will be included in Eastern Shore's upcoming 2017 rate case filing. The estimated cost of the project is $32.1 million. The estimated annual gross margin associated with this project, assuming recovery in the 2017 rate case filing, is approximately $4.5 million.
TETLP Capacity Expansion Project: On October 13, 2015, Eastern Shore submitted an application to the FERC to make certain measurement and related improvements at its TETLP interconnect facilities which will enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/day, for a total capacity of 160,000 Dts/d. Eastern Shore expects the project to be approved by the end of the year and in service by the end of February 2016. On a short-term basis, we anticipate that Eastern Shore will generate approximately $2.1 million in additional gross margin.

Eight Flags: Eight Flags, one of our unregulated energy subsidiaries, is engaged in the development and construction of a CHP plant in Nassau County, Florida. This CHP plant, which will consist of a natural-gas-fired turbine and associated electric generator, is designed to generate approximately 20 megawatts of base load power and will include a heat recovery system generator capable of providing approximately 75,000 pounds per hour of unfired steam. Eight Flags will sell the power generated from the CHP plant to FPU for distribution to its retail electric customers pursuant to a 20-year power purchase agreement. It will also sell the steam to an industrial customer pursuant to a separate 20-year contract. FPU will transport natural gas through its distribution system to Eight Flags’ CHP plant, which will produce power and steam. On a consolidated basis, this project is expected to generate approximately $7.3 million in annual gross margin, which could fluctuate based upon various factors, including, but not limited to, the quantity of steam delivered and the CHP plant’s hours of operations. Eight Flags' CHP plant is expected to be operational at the beginning of the third quarter of 2016. Our total projected investment, by Eight Flags and our affiliates, to construct the CHP plant and associated facilities is approximately $40.0 million.

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

Project	Estimated In-Service Date	Estimate for Annualized Margin	2016	2017
White Oak Mainline Expansion Project in Kent County, Delaware	Third quarter of 2016	$5,400	$5,400	$5,800
Eastern Shore System Reliability Project	Late third quarter of 2016	4,500	—	2,250
Eastern Shore TETLP Capacity Expansion Project	February 2016	2,100	2,100	2,100
Eight Flags CHP plant in Nassau County, Florida	Early third quarter of 2016	7,300	3,700	7,300
		$19,300	$11,200	$17,450

Other factors contributing to gross margin increase

Weather and Consumption

Weather was not a significant factor in the gross margin increase for the quarter ended September 30, 2015, compared to the same period in 2014. Weather was also not a significant factor in the gross margin increase for the nine months ended September 30, 2015, compared to the same period in 2014, because the first quarter of 2015 and 2014 were both significantly colder than normal (10-year average weather) on the Delmarva Peninsula. The following tables summarize the heating degree-day ("HDD") and cooling degree-day ("CDD") information for the three and nine months ended September 30, 2015 and 2014 and the gross margin variance resulting from weather fluctuations in those periods.

HDD and CDD Information

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Variance	2015	2014	Variance
Delmarva						
Actual HDD	41	89	(48)	3,249	3,262	(13)
10-Year Average HDD ("Normal")	65	61	4	2,908	2,893	15
Variance from Normal	(24)	28		341	369	
Florida						
Actual HDD	—	—	—	501	574	(73)
10-Year Average HDD ("Normal")	—	—	—	557	555	2
Variance from Normal	—	—		(56)	19	
Florida						
Actual CDD	1,591	1,528	63	2,827	2,498	329
10-Year Average CDD ("Normal")	1,524	1,519	5	2,506	2,501	5
Variance from Normal	67	9		321	(3)	

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Gross Margin Variance attributed to Weather

(in thousands)	Q3 2015 vs. Q3 2014	Q3 2015 vs. Normal	Q3 2014 vs. Normal	YTD 2015 vs. YTD 2014	YTD 2015 vs. Normal	YTD 2014 vs. Normal
Delmarva						
Regulated Energy segment	$(157)	$(31)	$167	$(87)	$872	$803
Unregulated Energy segment	(8)	27	(13)	20	1,005	1,037
Florida						
Regulated Energy segment	(232)	(40)	38	134	(239)	(284)
Unregulated Energy segment	—	—	—	(10)	122	81
Total	$(397)	$(44)	$192	$57	$1,760	$1,637

Propane prices

Higher retail margins per gallon generated $597,000 and $5.7 million in additional gross margin by the Delmarva propane distribution operation for the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014. A large decline in propane prices in the first quarter of 2015 had a significant impact on the amount of revenue and cost of sales associated with our propane distribution operations. Based on the Mont Belvieu wholesale propane index, propane prices in the first quarter of 2015 were approximately 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 cost in addition to the decrease in wholesale prices, which generated increased retail margins per gallon. During the second and third quarters of 2015, wholesale propane prices continued to remain significantly lower than prices in the same quarters of 2014.

In Florida, higher retail propane margins per gallon as a result of local market conditions generated $432,000 and $1.1 million of additional gross margin for the three and nine months ended September 30, 2015, respectively.

These market conditions, which are influenced by competition with other propane suppliers as well as the availability and price of alternative energy sources, may fluctuate based on changes in demand, supply and other energy commodity prices. The level of retail margins per gallon generated during the first nine months of 2015 is not typical and, therefore, is not included in our long-term financial plans or forecasts.

Xeron, which benefits from wholesale price volatility by entering into trading transactions, generated additional gross margin of $131,000 for the three months ended September 30, 2015. On a year-to-date basis, Xeron experienced a gross margin decrease of $854,000, compared to the same period in 2014, due to lower wholesale price volatility.

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $250,000 and $1.1 million in additional gross margin for the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014, due to an increase in residential, commercial and industrial customers served. The number of residential customers on the Delmarva Peninsula increased by 2.7 percent in the third quarter of 2015, compared to the same quarter in 2014. The natural gas distribution operations in Florida generated $443,000 and $1.4 million in additional gross margin for the three and nine months ended September 30, 2015, respectively, compared to the same periods in 2014, due primarily to an increase in commercial and industrial customers in Florida.

Capital Expenditures

We have revised our capital expenditures forecast for 2015 to be in the range of $130.0 million to $160.0 million, excluding amounts expended to acquire Gatherco. This range represents a significant increase over the average level of annual capital expenditures during the past three years, which equaled $94.8 million. The updated capital forecast reflects a shift in the timing of certain capital expenditures from 2015 to 2016. Major projects currently underway, such as the Eight Flags' CHP plant and associated facilities, anticipated new facilities to serve an industrial customer in Kent County, Delaware under the OPT ≤ 90 Service, and additional GRIP investments projected for 2015, account for approximately $99.0 million of the capital expenditures forecast for 2015. In addition, Eastern Shore is seeking FERC approval of a $32.1 million project to construct facilities that will improve the overall reliability and flexibility of its pipeline system. Capital expenditures are subject to continuous review and

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modification by our management and Board of Directors, and some 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 order to fund the 2015 capital expenditures currently budgeted, we expect to increase the level of borrowings during the remainder of 2015 to supplement cash provided by operating activities. Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent, and we have maintained a ratio of equity to total capitalization, including short-term borrowings, between 54 and 60 percent during the past three years. If we increase the level of debt during 2015 and 2016 to fund the budgeted capital expenditures, our ratio of equity to total capitalization, including short-term borrowings, will temporarily decline.

On October 8, 2015, we entered into the Revolver with the Lenders, which increased our borrowing capacity by $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we entered into a long-term private placement Shelf Agreement also for $150.0 million. The exact timing of any long-term debt or equity issuance(s) will be based on market conditions. In addition, for larger capital projects, we will seek to align, as much as feasible, any such long-term debt or equity issuance(s) with the earnings associated with commencement of service on such projects. For additional information on the Shelf Agreement and Revolver, see Note 14, Long-Term Debt, and Note 15, Short-Term Borrowing in the Condensed Consolidated Financial Statements.

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Regulated Energy Segment

For the quarter ended September 30, 2015 compared to the quarter ended September 30, 2014

	Three Months Ended September 30, 2015	2014	Increase (decrease)
(in thousands)			
Revenue	$63,796	$59,356	$4,440
Cost of sales	23,161	23,040	121
Gross margin	40,635	36,316	4,319
Operations & maintenance	19,882	18,906	976
Depreciation & amortization	6,129	5,633	496
Other taxes	2,796	2,575	221
Other operating expenses	28,807	27,114	1,693
Operating income	$11,828	$9,202	$2,626

Operating income for the Regulated Energy segment for the quarter ended September 30, 2015 was $11.8 million, an increase of $2.6 million, or 28.5 percent, compared to the same quarter in 2014. The increased operating income reflects additional gross margin of $4.3 million, which was partially offset by a net increase in other operating expenses of $1.7 million to support growth.

Gross Margin

Items contributing to the quarter-over-quarter increase of $4.3 million, or 11.9 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2014	$36,316
Factors contributing to the gross margin increase for the three months ended September 30, 2015:	
Service expansions	1,708
Additional revenue from GRIP in Florida	1,144
Natural gas distribution customer growth	693
FPU electric base rate increase	673
Growth in natural gas transmission services (other than service expansions)	203
Other	(101)
Gross margin for the three months ended September 30, 2015	$40,635

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

Service Expansions

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

- $1.1 million from interruptible service that commenced in April 2015 to an industrial customer in Kent County, Delaware. The interruptible service is expected to generate $1.7 million of gross margin in 2015, and it is expected to be replaced by a 20-year OPT ≤ 90 Service beginning in the third quarter of 2016.
- $463,000 from a new service to the same industrial customer in Kent County, Delaware, that commenced on October 1, 2014, upon completion of new facilities, including approximately 5.5 miles of pipeline lateral and metering facilities extending from Eastern Shore's mainline to the industrial customer facility. This service is expected to generate $1.8 million of gross margin in 2015.
- $340,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.

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- These increases were partially offset by a decrease in gross margin of $150,000 due primarily to a decrease in the reservation rate for a 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 through August 2020 at a lower reservation rate. The increased Dts/d to be transported under the contract, net of the lower reservation rate, is expected to generate $2.3 million of gross margin in 2015, compared to $1.9 million of gross margin generated in 2014.

Additional Revenue from GRIP in Florida

Additional GRIP investments during 2014 and 2015 by our Florida natural gas distribution operations generated $1.1 million in additional gross margin.

Natural Gas Distribution Customer Growth

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

- $443,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers; and
- $250,000 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

FPU's electric distribution operation generated additional gross margin of $673,000 due to higher base rates approved by the Florida PSC 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.

Growth in Natural Gas Transmission Services (Other Than Service Expansions)

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

- $236,000 from natural gas transmission service to commercial customers in Florida, partially offset by a decrease of $34,000 from interruptible service to an industrial customer in New Castle County, Delaware.

Other Operating Expenses

The increase in other operating expenses was due primarily to:

- $696,000 in higher payroll and benefits costs as a result of additional personnel to support growth;
- $507,000 in higher depreciation, asset removal and property tax costs associated with recent capital investments to support growth; and
- $208,000 in higher accruals for incentive compensation as a result of the higher quarterly financial results.

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For the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014

	Nine Months Ended September 30, 2015	2014	Increase (decrease)
(in thousands)			
Revenue	$235,438	$223,168	$12,270
Cost of sales	101,415	102,020	(605)
Gross margin	134,023	121,148	12,875
Operations & maintenance	59,648	55,416	4,232
Depreciation & amortization	18,109	16,783	1,326
Other taxes	8,650	7,945	705
Other operating expenses	86,407	80,144	6,263
Operating income	$47,616	$41,004	$6,612

Operating income for the Regulated Energy segment for the nine months ended September 30, 2015 was $47.6 million, an increase of $6.6 million, or 16.1 percent, compared to the same period in 2014. The increased operating income reflects additional gross margin of $12.9 million and $1.5 million received in connection with the customer billing system settlement, which were partially offset by an increase in other operating expenses of $7.8 million to support growth.

Gross Margin

Items contributing to the period-over-period increase of $12.9 million, or 10.6 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2014	$121,148
Factors contributing to the gross margin increase for the nine months ended September 30, 2015:	
Service expansions	4,085
Additional revenue from GRIP in Florida	3,070
Natural gas distribution customer growth	2,517
FPU electric base rates increase	2,366
Growth in natural gas transmission services (other than service expansions)	633
Other	204
Gross margin for the nine months ended September 30, 2015	$134,023

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

Service Expansions

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

- $1.5 million from interruptible service that commenced in April 2015 to an industrial customer facility in Kent County, Delaware mentioned above. The interruptible service is expected to generate $1.7 million in 2015, and it is expected to be replaced by a 20-year OPT ≤ 90 Service beginning in the third quarter of 2016.
- $1.4 million from a new service to the same industrial customer in Kent County, Delaware, that commenced on October 1, 2014 upon completion of new facilities, which included approximately 5.5 miles of pipeline lateral and metering facilities extending from Eastern Shore's mainline to the new industrial customer facility. This service is expected to generate $1.8 million of gross margin in 2015.
- $509,000 from a short-term contract with an existing industrial customer in New Castle County, Delaware to provide 50,000 Dts/d of service from April 2014 to April 2015. This contract was subsequently amended to provide 55,580 Dts/d of service at a lower reservation rate through August 2020. Although the lower rate decreased gross margin by $384,000

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for the nine months ended September 30, 2015, the extension of the contract at a higher volume generated additional gross margin of $893,000 for the nine months ended September 30, 2015. This service is expected to generate $2.3 million of gross margin in 2015 compared to $1.9 million of gross margin generated in 2014.

- $233,000 from another short-term contract with the same industrial customer in New Castle County, Delaware, to provide an additional 10,000 Dts/d of OPT≤90 Service transmission service from December 2014 to March 2015.
- $501,000 from natural gas transmission service as part of the major expansion initiative in Polk County, Florida.

Additional Revenue from GRIP in Florida

GRIP investments during 2014 and 2015 by our Florida natural gas distribution operations generated $3.1 million in additional gross margin.

Natural Gas Distribution Customer Growth

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

- $1.4 million from Florida natural gas customer growth due primarily to new services to commercial and industrial customers; and
- $1.1 million from a 2.7-percent increase in residential customers in the Delmarva natural gas distribution operations, as well as growth in commercial and industrial customers in Worcester County, Maryland.

FPU Electric Base Rate Increase

FPU's electric distribution operation generated additional gross margin of $2.4 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.

Growth in Natural Gas Transmission Services (Other Than Service Expansions)

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

- $559,000 from natural gas transmission service to commercial customers in Florida, and
- $57,000 from interruptible service to an industrial customer in New Castle County, Delaware.

Other Operating Expenses

The increase in other operating expenses was due primarily to:

- $1.9 million in higher payroll and benefits costs as a result of additional personnel to support growth and increased overtime on the Delmarva Peninsula in early 2015 due to colder weather;
- $1.3 million in higher depreciation, asset removal and property tax costs associated with recent capital investments to support growth;
- $987,000 in legal and consulting costs associated with the billing system settlement and other initiatives;
- $811,000 in higher accruals for incentive compensation as a result of improved year-to-date financial performance;
- $680,000 in higher service contractor and other consulting costs;
- $497,000 in additional amortization expense due to a change in the amortization of regulatory assets and liabilities, primarily in the Florida electric distribution operation; and
- $353,000 in additional costs for facility maintenance.

These increases were partially offset by a gain of $1.5 million from the billing system settlement, which reduced other operating expenses for the nine months ended September 30, 2015.

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Unregulated Energy Segment

For the quarter ended September 30, 2015 compared to the quarter ended September 30, 2014

	Three Months Ended September 30,		Increase
	2015	2014	(decrease)
(in thousands)			
Revenue	$29,609	$27,071	$2,538
Cost of sales	19,402	20,623	(1,221)
Gross margin	10,207	6,448	3,759
Operations & maintenance	9,305	7,063	2,242
Depreciation & amortization	1,483	1,014	469
Other taxes	441	343	98
Other operating expenses	11,229	8,420	2,809
Operating Loss	$(1,022)	$(1,972)	$950

Operating loss for the Unregulated Energy segment decreased by $950,000, to $1.0 million in the third quarter of 2015, compared to $2.0 million in the same quarter of 2014. The Unregulated Energy segment typically reports an operating loss in the third quarter due to the seasonal nature of our operations of a large portion of this segment. The results for the third quarter include gross margin of $2.0 million and other operating expenses of $1.9 million from Aspire Energy of Ohio. Excluding these impacts, gross margin increased by $1.7 million, which was partially offset by an $877,000 increase in other operating expenses.

Gross Margin

Items contributing to the quarter-over-quarter increase of $3.8 million, or 58.3 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended September 30, 2014	$6,448
Factors contributing to the gross margin increase for the three months ended September 30, 2015:	
Contributions from acquisitions	2,047
Increased retail propane margins	1,029
Natural gas marketing	479
Other	204
Gross margin for the three months ended September 30, 2015	$10,207

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

Contributions from Acquisitions

Aspire Energy of Ohio generated $2.0 million in additional gross margin for the three months ended September 30, 2015.

Increased Retail Propane Margins

Higher retail propane margins for our Delmarva Peninsula and Florida propane distribution operations during the third quarter of 2015 generated $597,000 and $432,000, respectively, in additional gross margin. The higher retail propane margins were due to the retail pricing strategy guided by local market conditions and lower propane costs.

Natural Gas Marketing

Our natural gas marketing operation generated $479,000 in additional gross margin for the quarter ended September 30, 2015, as the results of our strategic growth initiatives have started to materialize.

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Other Operating Expenses

The increase in other operating expenses was due primarily to:

- $1.9 million in costs from the operation of Aspire Energy of Ohio, following the acquisition of Gatherco on April 1, 2015;
- $443,000 in higher payroll and benefits costs primarily due to additional personnel hired to support growth;
- $141,000 in higher depreciation and property tax costs reflecting a higher level of assets resulting from our growth;
- $126,000 in additional costs for facility maintenance; and
- $102,000 in higher accruals for incentive compensation as a result of the higher year-to-date financial results and a larger workforce.

For the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014

	Nine Months Ended September 30,		Increase
	2015	2014	(decrease)
(in thousands)			
Revenue	$123,164	$141,365	$(18,201)
Cost of sales	77,235	105,802	(28,567)
Gross margin	45,929	35,563	10,366
Operations & maintenance	26,993	22,508	4,485
Depreciation & amortization	3,973	2,981	992
Other taxes	1,297	1,231	66
Other operating expenses	32,263	26,720	5,543
Operating Income	$13,666	$8,843	$4,823

Operating income for the Unregulated Energy segment increased by $4.8 million, or 54.5 percent, to $13.7 million in the first nine months of 2015, compared to $8.8 million in the same period of 2014. Excluding the impact generated by Aspire Energy of Ohio as a result of the Gatherco acquisition on April 1, 2015 ($3.7 million in gross margin and $3.8 million of other operating expenses), the increased operating income was driven by a $6.7 million increase in gross margin, which was partially offset by a $1.7 million increase in other operating expenses.

Gross Margin

A significant decline in natural gas and propane commodity prices decreased both revenue and related cost of commodities sold to our propane distribution and natural gas marketing customers, resulting in a period-over-period increase of $10.4 million, or 29.2 percent, in gross margin. Items contributing to this increase are listed in the following table:

(in thousands)	
Gross margin for the nine months ended September 30, 2014	$35,563
Factors contributing to the gross margin increase for the nine months ended September 30, 2015:	
Increase in retail propane margins	6,742
Contributions from acquisitions	3,679
Propane wholesale marketing	(854)
Natural gas marketing	404
Increased customer consumption - weather and other	258
Other	137
Gross margin for the nine months ended September 30, 2015	$45,929

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

Increased Retail Propane Margins
Higher retail propane margins for our Delmarva Peninsula and Florida propane distribution operations during the first nine months of 2015 generated $5.7 million and $1.1 million, respectively, in additional gross margin. A large decline in wholesale propane prices during 2015, coupled with favorable supply management and hedging activities, resulted in a decrease in the average propane costs for the Delmarva propane distribution operation, which generated increased retail propane margins per gallon.

Contributions from Acquisitions
Aspire Energy of Ohio generated $3.7 million in additional gross margin in the first nine months of 2015.

Lower Propane Wholesale Marketing Results
Xeron's gross margin decreased by $854,000 during the first nine months of 2015, compared to the same period in 2014, as a result of a 12-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 nine months of 2014, which resulted in unusually high profitability during that period.

Natural Gas Marketing
Our natural gas marketing operation generated $404,000 in additional gross margin for the first nine months of 2015, compared to the same period in 2014. The increase in natural gas marketing margin was primarily from execution of its growth strategy.

Increased Customer Consumption - Weather and Other
Higher customer consumption increased gross margin by $258,000. The increase was due to an increase in non-weather consumption on the Delmarva Peninsula partially offset by decreased non-weather consumption in Florida.

Other Operating Expenses
Other operating expenses increased by $5.5 million due primarily to $3.8 million of other operating expenses incurred by Aspire Energy of Ohio. The remaining increase in other operating expenses was due primarily to:

- $1.0 million in higher payroll and benefits expense due to increased seasonal overtime and additional resources hired to support growth;
- $379,000 in additional costs for facility maintenance;
- $337,000 in increased accruals for incentive compensation as a result of improved year-to-date financial results in 2015 as well as a larger workforce; and
- $184,000 in lower expenses for credit and collections activities, which partially offset the above increases in expenses.

Interest Charges
For the quarter ended September 30, 2015 compared to the quarter ended September 30, 2014
Interest charges for the three months ended September 30, 2015 decreased slightly by approximately $3,000, compared to the same quarter in 2014.

For the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014
Interest charges for the nine months ended September 30, 2015 increased by approximately $471,000, or seven percent, compared to the same period in 2014. The increase in interest charges is attributable to an increase of

$262,000 in long-term interest charges as a result of $50.0 million of Notes issued in May 2014 and an increase of $122,000 in interest expense from short-term borrowings.

Income Taxes
For the quarter ended September 30, 2015 compared to the quarter ended September 30, 2014

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Income tax expense was $3.3 million in the third quarter of 2015, compared to $2.1 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 was at 39.4 percent for the third quarter of 2015 and 39.6 percent for the third quarter of 2014.

For the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014
Income tax expense was $21.6 million in the nine months ended September 30, 2015, compared to $17.3 million in the same period 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 nine months 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. Our current forecast of capital expenditures for 2015 ranges from $130.0 million to $160.0 million. The following table sets forth the revised 2015 forecast of capital expenditures by segment:

	Range of Capital Expenditures	
(dollars in thousands)	Low	High
Regulated Energy:		
Natural gas distribution	$59,589	$80,281
Natural gas transmission	21,426	30,734
Electric distribution	4,824	4,824
Total Regulated Energy	85,839	115,839
Unregulated Energy:		
Propane distribution	9,196	9,196
Other unregulated energy	28,447	28,447
Total Unregulated Energy	37,643	37,643
Other	6,518	6,518
Total 2015 projected capital expenditures	$130,000	$160,000

The current forecast of capital expenditures is a significant increase over our average annual level of capital expenditures over the past three years of $94.8 million. This increase 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 reduction from the original capital expenditure budget of $223.4 million to the current forecast of capital expenditures is due primarily to a shift in the timing of certain capital expenditures from 2015 to 2016.

Actual capital requirements may vary from 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 acquisition of Gatherco, which we completed on April 1, 2015, was not included in our original capital budget of $223.4 million or in our current 2015 capital expenditure forecast 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 $27.5 million in cash. We also acquired $6.8 million of Gatherco's cash at closing and assumed $1.7 million of Gatherco’s debt, which was paid off on the same day.

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Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following table presents our capitalization, excluding and including short-term borrowings, as of September 30, 2015 and December 31, 2014:

	September 30, 2015			December 31, 2014		
(in thousands)						
Long-term debt, net of current maturities	$155,909	31	%	$158,486	35	%
Stockholders’ equity	353,315	69	%	300,322	65	%
Total capitalization, excluding short-term debt	$509,224	100	%	$458,808	100	%

	September 30, 2015			December 31, 2014		
(in thousands)						
Short-term debt	$127,093	20	%	$88,231	16	%
Long-term debt, including current maturities	165,048	26	%	167,595	30	%
Stockholders’ equity	353,315	54	%	300,322	54	%
Total capitalization, including short-term debt	$645,456	100	%	$556,148	100	%

Included in the long-term debt balances at September 30, 2015 and December 31, 2014, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($3.8 million and $4.8 million, respectively, net of current maturities and $5.2 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, currently estimated to be in the range of $130.0 million to $ 160.0 million, we expect to increase the level of borrowings during the remainder of 2015 to supplement cash provided by operating activities. Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. We have maintained a ratio of equity to total capitalization, including short-term borrowings, between 54 percent and 60 percent during the past three years. As we increase the level of debt during 2015 to fund the capital expenditures we expect to fund at this time, the ratio of equity to total capitalization, including short-term borrowings, will temporarily decline. As described below under “Short-term Borrowings”, we entered into a new Revolver with the Lenders on October 8, 2015, which increased our borrowing capacity by $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we also entered in a long-term private placement Shelf Agreement with Prudential that is further described below under “Shelf Agreement.”

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

Short-term Borrowings

Our outstanding short-term borrowings at September 30, 2015 and December 31, 2014 were $127.1 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. As of September 30, 2015, we had 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, were available under uncommitted lines of credit, which expired on October 31, 2015, and were not renewed. 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.

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

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Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25% or less. Interest is payable quarterly and the Revolver is subject to a commitment fee on the unused portion of the facility. We may extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million with any increase at the sole discretion of each Lender. On October 19, 2015, we borrowed $25.0 million under the Revolver.

Shelf Agreement

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

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

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,	
	2015	2014
(in thousands)		
Net cash provided by (used in):		
Operating activities	$98,684	$65,019
Investing activities	(122,985)	(68,740)
Financing activities	23,508	2,650
Net decrease in cash and cash equivalents	(793)	(1,071)
Cash and cash equivalents—beginning of period	4,574	3,356
Cash and cash equivalents—end of period	$3,781	$2,285

Cash Flows Provided By Operating Activities

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

During the nine months ended September 30, 2015 and 2014, net cash provided by operating activities was $98.7 million and $65.0 million, respectively, resulting in an increase in cash flows of $33.7 million. Significant operating activities generating the cash flows change were as follows:

- The changes in net regulatory assets and liabilities increased cash flows by $15.3 million, due primarily to the change in fuel costs collected through the various fuel cost recovery mechanisms.
-

The change in income taxes receivable increased cash flows by $14.4 million, due primarily to the receipt of a tax refund related to our 2014 federal income tax obligation. Our tax deductions, which were higher-than-projected, due to bonus depreciation (approved by the President of the United States in December 2014), reduced our 2014 federal income tax obligation.

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- The changes in net accounts receivable and payable decreased cash flows by $2.8 million, due primarily to the timing of the collections and payments associated with trading contracts entered into by our propane wholesale marketing subsidiary, which were partially offset by an increase in net cash flows from receivables and payables in various other operations.
- Net income, adjusted for reconciling activities, increased cash flows by $8.2 million, due primarily to higher earnings and higher non-cash adjustments for depreciation and amortization.
- Net cash flows from changes in propane, natural gas and materials inventories decreased by approximately $971,000, compared to 2014.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $123.0 million and $68.7 million during the nine months ended September 30, 2015 and 2014, respectively, resulting in a decrease in cash flows of $54.2 million. Significant investing activities generating the cash flows change were as follows:

- An increase in cash paid for capital expenditures, due primarily to our GRIP investment in our Florida natural gas distribution operations and Eight Flags' construction of the CHP plant, decreased cash flows by $32.9 million.
- We paid $20.7 million ($27.5 million paid less $6.8 million of cash acquired) in conjunction with the acquisition of Gatherco on April 1, 2015.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities totaled $23.5 million in the first nine months of 2015, compared to $2.7 million in the same period in 2014. The increase in net cash provided by financing activities during the first nine months of 2015 was due primarily to $69.9 million in higher borrowing under our line of credit agreements and a $3.5 million increase in cash overdrafts, which were partially offset by $50.0 million in proceeds from the issuance of long-term debt in May 2014 and $1.7 million of outstanding debt assumed in the Gatherco merger that was paid off immediately after the closing of the merger on April 1, 2015.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily Xeron and PESCO, which provide for the payment of propane and natural gas purchases in the event that the subsidiary defaults. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at September 30, 2015 was $36.1 million, with the guarantees expiring on various dates through September 22, 2016.

We issued a letter of credit for $1.0 million, which was renewed through September 12, 2016, 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 $1.2 million, which expires on October 31, 2016, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company, we renewed and decreased to $24,000 the letter of credit to our former primary insurance company, which will expire on April 8, 2016. We have also issued a letter of credit of $1.0 million, which expires on March 31, 2016, related to PESCO's transactions at the Natural Gas Exchange, Inc.

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

There have been no draws on these letters of credit as of September 30, 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.

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 September 30, 2015.

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	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]	$40,246	$6,088	$1,425	$ —	$47,759
Forward purchase contracts - Propane [2]	1,336	—	—	—	1,336
Total	$41,582	$6,088	$1,425	$ —	$49,095

(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 September 30, 2015, we were involved in regulatory matters in each of the jurisdictions in which we operate. Our significant regulatory matters are fully described in Note 4, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Recent Authoritative Pronouncements on Financial Reporting and Accounting

Recent accounting developments applicable to us and their impact on our financial position, results of operations and cash flows are described in Note 1, Summary of Accounting Policies, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes and secured debt. All of our long-term debt, excluding a capital lease obligation, is fixed-rate debt and was not entered into for trading purposes. The carrying value of our long-term debt, including current maturities, but excluding a capital lease obligation, was $159.9 million at September 30, 2015, as compared to a fair value of $175.8 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

Our propane distribution business is exposed to market risk as a result of our propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 6.5 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers’ peak requirements and to serve metered customers. 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

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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 September 30, 2015 is presented in the following table:

At September 30, 2015	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	2,940,000	$0.4750 - $0.5288	$0.5210
Purchase	2,940,000	$0.4350 - $0.5025	$0.4545

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the fourth 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 September 30, 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)	September 30, 2015	December 31, 2014
Mark-to-market energy assets, including put and call options and swap agreements	$286	$1,055
Mark-to-market energy liabilities, including swap agreements	$154	$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 September 30, 2015. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2015.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 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 Quarterly Report on Form 10-Q. Additional risks and uncertainties not known to us at present, or that we currently deem immaterial also may affect the Company. The occurrence of any of these known or unknown risks could have a material adverse impact on our business, financial condition, and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
July 1, 2015 through July 31, 2015 [1]	369	$54.45	—	—
August 1, 2015 through August 31, 2015	—	$—	—	—
September 1, 2015 through September 30, 2015	—	$—	—	—
Total	369	$54.45	—	—

(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 September 30, 2015, 369 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

4.1	Private Shelf Agreement dated October 8, 2015, between Chesapeake Utilities Corporation, as issuer, and Prudential Investment Management Inc., relating to the purchase of Chesapeake Utilities Corporation unsecured senior notes, is filed herewith.
10.1	Revolving Credit Agreement dated October 8, 2015, between Chesapeake Utilities Corporation and PNC Bank, National Association, Bank of America, N.A., Citizens Bank N.A., Royal Bank of Canada and Wells Fargo Bank, National Association as lenders, is filed herewith.
10.2	Form of Performance Share Agreement, dated March 6, 2015 for the period 2015 to 2017, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and James F. Moriarty, is filed herewith.
31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated November 5, 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 November 5, 2015.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 5, 2015.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated November 5, 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: November 5, 2015