CHESAPEAKE UTILITIES CORP
Form 10-Q
May 03, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended: March 31, 2013

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 9,615,237 shares outstanding as of April 30, 2013.

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GLOSSARY OF KEY TERMS AND DEFINITIONS

KEY TERMS

Bulk delivery: Propane delivery to customers based on the level of propane remaining in the tank located at the customer s premises. We invoice and record revenues for the bulk delivery service at the time of delivery, rather than upon a customer s actual usage.

Cost of sales: Includes the purchased cost of natural gas, electricity and propane commodities, pipeline capacity costs needed to transport and store natural gas, transmission costs for electricity, transportation costs to transport propane purchases to our storage facilities and the direct cost of labor spent on revenue-producing activities.

Delmarva natural gas distribution operation: Chesapeake s Delaware and Maryland divisions.

Delmarva Peninsula: A peninsula on the east coast of the United States of America occupied by Delaware and portions of Maryland and Virginia. Chesapeake provides natural gas distribution, transmission and marketing services and propane distribution service to customers on the Delmarva Peninsula.

Electric distribution: Regulated electric distribution utility service. Florida Public Utilities Company provides this service to customers in northeast and northwest Florida. This service is regulated by the Florida Public Service Commission.

Florida natural gas distribution operation: Chesapeake s Florida division and the natural gas operation of Florida Public Utilities Company, including its Indiantown division.

Gross margin: A non-GAAP measure, which Chesapeake uses to evaluate the performance of its business segments. Gross margin is calculated by deducting the cost of sales from operating revenues. A more detailed description of gross margin, including how we calculate it, is provided in the Management s Discussion and Analysis of Financial Condition and Results of Operations section of this Quarterly Report on Form 10-Q.

Interruptible service: Large commercial customers whose regulated utility service can be temporarily interrupted in order for the utility to meet the needs of firm service customers. The interruptible service customers pay lower delivery rates than firm service customers and they must be able to readily substitute an alternate fuel for natural gas.

Margins per gallon: A measure of profitability for propane distribution sales, calculated for each gallon of propane sold by deducting the cost of propane sold from the propane revenue.

Mark-to-market: The process of adjusting the carrying value of a position held in our forward contracts and derivative instruments to reflect their current fair value.

Natural gas distribution: Regulated natural gas distribution utility service. Both Chesapeake Utilities Corporation, through its Delaware, Maryland and Florida divisions, and Florida Public Utilities Company provide this service. This service is regulated by the Public Service Commission of each respective state.

Natural gas marketing: Unregulated natural gas supply and supply management service for the sale of the natural gas commodity directly to residential, commercial and industrial customers through competitively-priced contracts. Peninsula Energy Services Company, Inc. provides this service.

Natural gas transmission: Regulated natural gas transportation service provided by Eastern Shore Natural Gas Company and Peninsula Pipeline Company, Inc. The interstate transportation service provided by Eastern Shore Natural Gas Company is regulated by the Federal Energy Regulatory Commission. The intrastate transportation service provided by Peninsula Pipeline Company, Inc. in Florida is regulated by the Florida Public Service Commission.

Normal Weather: The most recent 10 year average of heating and/or cooling degree-days in a particular geographic area.

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Propane distribution: Unregulated propane distribution service to residential, commercial, industrial and wholesale customers. This service can be provided through delivery to a propane tank located on the customer s premises or through an underground pipeline system.

Propane wholesale marketing: Unregulated service offering where propane is marketed to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States of America. This service typically utilizes forward or other option contracts that are financially settled. Xeron, Inc. provides this service.

Regulated energy: The largest operating segment of Chesapeake Utilities Corporation. All operations in this segment are regulated as to their rates and service, by the Public Service Commission having jurisdiction in each state in which the Company operates or by the Federal Energy Regulatory Commission.

DEFINITIONS

ASU: Accounting Standards Update

BravePoint: BravePoint®, Inc., an advanced information services subsidiary, headquartered in Norcross, Georgia

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

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

Delaware City Refinery: An oil refinery located in Delaware City, Delaware and owned by PBF Energy Inc.

DSCP: Directors Stock Compensation Plan

Dts/d: Dekatherms per day

DPA: The Division of the Public Advocate

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

ESG: Eastern Shore Gas Company and its affiliates

EPA: United States Environmental Protection Agency

FASB: Financial Accounting Standards Board

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

FDEP: Florida Department of Environmental Protection

FDOT: Florida Department of Transportation

FGT: Florida Gas Transmission Company

FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake as of October 28, 2009, the date we acquired FPU

Franchise Agreement: The agreement between the City of Marianna, Florida and Florida Public Utilities Company, which granted a franchise to Florida Public Utilities Company for the operation and distribution and/or sale of electric energy

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

Glades: Glades Gas Co., Inc.

GSR: Gas Service Rates

Gulf Power: Gulf Power Company

Gulfstream: Gulfstream Natural Gas System, LLC

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

IGC: Indiantown Gas Company

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

MDE: Maryland Department of Environment

Marianna Commission: The City Commission of Marianna, Florida

NAM: Natural Attenuation Monitoring

NRG: NRG Energy Center Dover LLC

OTC: Over-the-counter

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

Peninsula Pipeline: Peninsula Pipeline Company, Inc., a wholly-owned Florida intrastate pipeline subsidiary of Chesapeake

PIP: Performance Incentive Plan

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

Sanford Group: Florida Public Utilities Company and other responsible parties involved with the Sanford environmental site

SEC: Securities and Exchange Commission

SERP: Supplemental Executive Retirement Plan

TETLP: Texas Eastern Transmission, LP

TOU: Time-of-use

Xeron: Xeron, Inc., a wholly-owned propane wholesale marketing subsidiary of Chesapeake, 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)

For the Three Months Ended March 31, *(in thousands, except shares and per share data)*	**2013**	**2012**
Operating Revenues		
Regulated energy	**$ 81,566**	$ 72,296
Unregulated energy	**54,991**	44,887
Other	**4,172**	3,731
Total operating revenues	**140,729**	120,914
Operating Expenses		
Regulated energy cost of sales	**41,615**	35,672
Unregulated energy and other cost of sales	**40,090**	34,593
Operations	**21,754**	19,955
Maintenance	**1,722**	1,976
Depreciation and amortization	**5,820**	5,761
Other taxes	**3,178**	2,884
Total operating expenses	**114,179**	100,841
Operating Income	**26,550**	20,073
Other income, net of other expenses	**289**	196
Interest charges	**2,072**	2,291
Income Before Income Taxes	**24,767**	17,978
Income taxes	**9,898**	7,251
Net Income	**$ 14,869**	$ 10,727
Weighted Average Common Shares Outstanding:		
Basic	**9,601,529**	9,571,270
Diluted	**9,678,950**	9,666,885
Earnings Per Share of Common Stock:		
Basic	**$ 1.55**	$ 1.12
Diluted	**$ 1.54**	$ 1.11
Cash Dividends Declared Per Share of Common Stock	**$ 0.365**	$ 0.345

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)

For the Three Months Ended March 31, *(in thousands)*	**2013**	**2012**
Net Income	**$ 14,869**	$ 10,727
Other Comprehensive Income (Loss), net of tax:		
Employee Benefits, net of tax:		
Amortization of prior service cost, net of tax of ($6) and ($6), respectively	**(9)**	(9)
Net gain, net of tax of $38 and $50, respectively	**58**	76
Total other comprehensive income	**49**	67
Comprehensive Income	**$ 14,918**	$ 10,794

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 *(in thousands, except shares and per share data)*	**March 31, 2013**	**December 31, 2012**
Property, Plant and Equipment		
Regulated energy	**$ 590,816**	$ 585,429
Unregulated energy	**71,787**	70,218
Other	**20,449**	20,067
Total property, plant and equipment	**683,052**	675,714
Less: Accumulated depreciation and amortization	**(160,199)**	(155,378)
Plus: Construction work in progress	**29,880**	21,445
Net property, plant and equipment	**552,733**	541,781
Current Assets		
Cash and cash equivalents	**2,608**	3,361
Accounts receivable (less allowance for uncollectible accounts of $1,008 and $826, respectively)	**62,891**	53,787
Accrued revenue	**11,241**	11,688
Propane inventory, at average cost	**5,614**	7,612
Other inventory, at average cost	**3,199**	5,841
Regulatory assets	**1,881**	2,736
Storage gas prepayments	**897**	3,716
Income taxes receivable		4,703
Deferred income taxes	**836**	791
Prepaid expenses	**4,452**	6,020
Mark-to-market energy assets	**150**	210
Other current assets	**146**	132
Total current assets	**93,915**	100,597
Deferred Charges and Other Assets		
Goodwill	**4,543**	4,090
Other intangible assets, net	**3,017**	2,798
Investments, at fair value	**4,526**	4,168
Regulatory assets	**76,360**	77,408
Receivables and other deferred charges	**3,363**	2,904
Total deferred charges and other assets	**91,809**	91,368
Total Assets	**$ 738,457**	$ 733,746

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 *(in thousands, except shares and per share data)*	**March 31, 2013**	**December 31, 2012**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	**$ 4,679**	$ 4,671
Additional paid-in capital	**150,527**	150,750
Retained earnings	**117,579**	106,239
Accumulated other comprehensive loss	**(5,013)**	(5,062)
Deferred compensation obligation	**994**	982
Treasury stock	**(994)**	(982)
Total stockholders equity	**267,772**	256,598
Long-term debt, net of current maturities	**100,952**	101,907
Total capitalization	**368,724**	358,505
Current Liabilities		
Current portion of long-term debt	**9,093**	8,196
Short-term borrowing	**47,635**	61,199
Accounts payable	**38,835**	41,992
Customer deposits and refunds	**26,788**	29,271
Accrued interest	**2,622**	1,437
Dividends payable	**3,504**	3,502
Income taxes payable	**4,196**	
Accrued compensation	**4,708**	7,435
Regulatory liabilities	**7,576**	1,577
Mark-to-market energy liabilities	**85**	331
Other accrued liabilities	**8,643**	7,226
Total current liabilities	**153,685**	162,166
Deferred Credits and Other Liabilities		
Deferred income taxes	**127,491**	125,205
Deferred investment tax credits	**103**	113
Regulatory liabilities	**5,336**	5,454
Environmental liabilities	**9,094**	9,114
Other pension and benefit costs	**33,890**	33,535
Accrued asset removal cost Regulatory liability	**38,554**	38,096
Other liabilities	**1,580**	1,558
Total deferred credits and other liabilities	**216,048**	213,075
Other commitments and contingencies (Note 5 and 6)		
Total Capitalization and Liabilities	**$ 738,457**	$ 733,746

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)

For the Three Months Ended March 31, *(in thousands)*	**2013**	**2012**
Operating Activities		
Net Income	**$ 14,869**	$ 10,727
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**5,820**	5,761
Depreciation and accretion included in other costs	**1,476**	1,398
Deferred income taxes, net	**2,208**	5,373
Gain on sale of assets	**(8)**	(36)
Unrealized (gain) loss on commodity contracts	**(214)**	60
Unrealized gain on investments	**(283)**	(317)
Realized gain on sales of investments, net	**(69)**	
Employee benefits	**211**	437
Share-based compensation	**381**	345
Other, net	**(3)**	(7)
Changes in assets and liabilities:		
Purchase of investments	**(7)**	(29)
Accounts receivable and accrued revenue	**(8,657)**	9,760
Propane inventory, storage gas and other inventory	**5,064**	5,830
Regulatory assets	**852**	914
Prepaid expenses and other current assets	**1,469**	1,452
Accounts payable and other accrued liabilities	**1,510**	(8,139)
Income taxes receivable	**8,899**	1,398
Accrued interest	**1,185**	1,290
Customer deposits and refunds	**(2,520)**	(409)
Accrued compensation	**(2,753)**	(2,305)
Regulatory liabilities	**5,711**	799
Other liabilities	**(173)**	248
Net cash provided by operating activities	**34,968**	34,550
Investing Activities		
Property, plant and equipment expenditures	**(16,217)**	(14,744)
Proceeds from sales of assets	**34**	2,170
Purchase of investments and acquisition	**(2,437)**	(124)
Environmental expenditures	**(20)**	(55)
Net cash used in investing activities	**(18,640)**	(12,753)
Financing Activities		
Common stock dividends	**(3,176)**	(2,989)
Purchase of stock for Dividend Reinvestment Plan	**(326)**	(327)
Change in cash overdrafts due to outstanding checks	**83**	(1,550)
Net repayment under line of credit agreements	**(13,647)**	(17,501)
Repayment of long-term debt	**(15)**	(20)
Net cash used in financing activities	**(17,081)**	(22,387)
Net Decrease in Cash and Cash Equivalents	**(753)**	(590)
Cash and Cash Equivalents Beginning of Period	**3,361**	2,637

Cash and Cash Equivalents End of Period	**$ 2,608**	$ 2,047

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)

(in thousands, except shares and per share data)	**Common Stock** Number of Shares[1]	**Common Stock** Par Value	Additional Paid-In Capital	Retained Earnings	**Accumulated Other** Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2011	**9,567,307**	**$ 4,656**	**$ 149,403**	**$ 91,248**	**($ 4,527)**	**$ 817**	**($ 817)**	**$ 240,780**
Net Income				28,863				28,863
Other comprehensive loss					(535)			(535)
Dividend Reinvestment Plan			(7)					(7)
Conversion of debentures	10,975	5	181					186
Share-based compensation [2] [3]	19,217	10	1,001					1,011
Tax benefit on share-based compensation			172					172
Deferred Compensation Plan						165	(165)	
Purchase of treasury stock	(1,019)						(45)	(45)
Sale and distribution of treasury stock	1,019						45	45
Dividends on share-based compensation				(64)				(64)
Cash dividends [4]				(13,808)				(13,808)
Balances at December 31, 2012	**9,597,499**	**4,671**	**150,750**	**106,239**	**(5,062)**	**982**	**(982)**	**256,598**
Net Income				14,869				14,869
Other comprehensive income					49			49
Dividend Reinvestment Plan			(2)					(2)
Conversion of debentures	2,642	1	44					45
Share-based compensation [2] [3]	13,921	7	(265)					(258)
Deferred Compensation Plan						12	(12)	
Purchase of treasury stock	(261)						(12)	(12)
Sale and distribution of treasury stock	261						12	12
Dividends on share-based compensation				(25)				(25)
Cash dividends [4]				(3,504)				(3,504)
Balances at March 31, 2013	**9,614,062**	**$ 4,679**	**$ 150,527**	**$ 117,579**	**($ 5,013)**	**$ 994**	**($ 994)**	**$ 267,772**

(1) Includes 33,722 and 33,461 shares at March 31, 2013 and December 31, 2012, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

(2) Includes amounts for shares issued for Directors compensation.

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For three months ended March 31, 2013 and for the year ended December 31, 2012, the Company withheld 10,411 and 5,670 shares, respectively, for taxes.

(4) Cash dividends per share for the periods ended March 31, 2013 and December 31, 2012 were $0.365 and $1.440, respectively.

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 Utilities Corporation, its divisio 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 Securities and Exchange Commission (SEC) and accounting principles generally accepted in the United States of America (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, 2012. In the opinion of management, these financial statements reflect normal recurring adjustments that are necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods presented.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is highest due to colder temperatures.

We have assessed and reported on subsequent events through the date of issuance of these condensed consolidated financial statements.

Reclassifications

We reclassified certain amounts in the condensed consolidated cash flows statement for the three months ended March 31, 2012 to conform to the current year s presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

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Financial Accounting Standards Board (FASB) Statements and Other Authoritative Pronouncements

Recently Adopted Accounting Standards

In February 2013, the FASB issued Accounting Standards Update (ASU) 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out Of Accumulated Other Comprehensive Income. ASU 2013-02 requires entities to report either on their income statement or disclose in footnotes to the financial statements the effects on net income from significant items that are classified out of the accumulated other comprehensive income for all reporting periods (annual and interim) covered by the financial statements. The standard also requires cross-reference to other disclosures currently required under GAAP for other reclassification items that are not required to be reclassified directly to net income. This standard is effective for us for fiscal periods beginning after December 15, 2012. We provided the required disclosures of ASU 2013-12 in Note 8, Accumulated Other Comprehensive Income (Loss). Other than providing the additional disclosures, the adoption of ASU 2013-02 had no impact on our financial position and results of operations.

In January 2013, the FASB issued ASU 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The FASB issued ASU 2013-01 in response to concerns raised by constituents regarding the potential broad scope of disclosure requirements upon adoption of ASU 2011-11. It limits the scope of the new balance sheet offsetting disclosures to derivatives, repurchase agreements and securities lending transactions to the extent that they are (i) offsetting in the financial statements or (ii) subject to an enforceable master netting arrangement or similar agreement. ASU 2013-01 became effective for us on January 1, 2013. The adoption of ASU 2013-01 had no material impact on our financial position and results of operations.

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures About Offsetting Assets and Liabilities. This standard amends the disclosure requirements on offsetting by requiring enhanced disclosures about financial instruments and derivative instruments that are either: (i) offset in accordance with existing guidance, or (ii) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. ASU 2011-11 became effective for us on January 1, 2013. The adoption of ASU 2011-11 had no material impact on our financial position and results of operations.

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2. Calculation of Earnings Per Share

For the Three Months Ended March 31, *(in thousands, except shares and per share data)*	**2013**	**2012**
Calculation of Basic Earnings Per Share:		
Net Income	**$ 14,869**	$ 10,727
Weighted average shares outstanding	**9,601,529**	9,571,270
Basic Earnings Per Share	**$ 1.55**	$ 1.12
Calculation of Diluted Earnings Per Share:		
Reconciliation of Numerator:		
Net Income	**$ 14,869**	$ 10,727
Effect of 8.25% Convertible debentures	**11**	14
Adjusted numerator Diluted	**$ 14,880**	$ 10,741
Reconciliation of Denominator:		
Weighted shares outstanding Basic	**9,601,529**	9,571,270
Effect of dilutive securities:		
Share-based Compensation	**23,132**	29,931
8.25% Convertible debentures	**54,289**	65,684
Adjusted denominator Diluted	**9,678,950**	9,666,885
Diluted Earnings Per Share	**$ 1.54**	$ 1.11

3. Acquisitions

Pending Acquisition of Eastern Shore Gas Company

On June 22, 2012, we entered into an agreement to purchase the operating assets of Eastern Shore Gas Company and its affiliates (collectively ESG, which are unrelated to our interstate natural gas transmission subsidiary). These assets are currently used to provide propane distribution service in Worcester County, Maryland to approximately 11,000 residential and commercial customers through underground propane gas distribution systems and to over 500 customers through bulk propane delivery service. The purchase price is approximately $16.5 million, which is subject to certain adjustments specified in the purchase agreement. At closing, we will enter into a capacity, supply and operating agreement with ESG for supply and storage of propane, which will be utilized to serve the ESG system customers. We are evaluating the potential conversion of some of the underground propane distribution systems to natural gas where such conversion is both economical and feasible. The transaction is subject to approval by the Maryland Public Service Commission (PSC), the receipt of consents of certain local jurisdictions to the assignment of certain franchise agreements and satisfaction of other closing conditions. On September 7, 2012, we filed an application with the Maryland PSC for approval of the purchase, and on April 8, 2013, we reached a settlement agreement with the parties in that proceeding, which, if accepted by the Maryland PSC, will approve the ESG acquisition, the overall regulatory framework to provide service in Worcester County, Maryland and recovery of propane supply and capacity costs through the purchased gas cost mechanism (see Note 4, Rates and Other Regulatory Activities, for additional information). The transaction, which is a cash purchase of assets, is expected to be completed in mid-2013. We expect to finance the acquisition using unsecured short-term debt.

Propane Acquisition

On February 5, 2013, Flo-Gas Corporation, our Florida propane distribution subsidiary, purchased the propane operating assets of Glades Gas Co., Inc. (Glades) for approximately $2.9 million. The purchased assets are used to provide propane distribution service to approximately 3,000 residential and commercial customers in Okeechobee, Glades and Hendry Counties, Florida. In connection with this acquisition, we recorded $1.6 million in property, plant and equipment, $502,000 in propane and other inventory, $300,000 in an intangible asset related to Glades customer list and $453,000 in goodwill. Valuation of certain property, plant and equipment and the intangible asset is preliminary and may be adjusted in the future based upon the final valuation, but no later than one year from the date of acquisition. All of the goodwill is expected to be deductible for income tax purposes.

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 Natural Gas Company (Eastern Shore), our natural gas transmission subsidiary, is subject to regulation by the Federal Energy Regulatory Commission (FERC); and Peninsula Pipeline Company, Inc. (Peninsula Pipeline), our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC. Chesapeake s Florida natural gas distribution division and the natural gas and electric operations of Florida Public Utilities Company (FPU) continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

Natural Gas Expansion Service Offerings: On June 25, 2012, the Delaware division filed with the Delaware PSC an application for proposed natural gas expansion service offerings in order to increase the availability of natural gas within its Delaware service areas. In this filing, the Delaware division is seeking approval from the Delaware PSC of the following:

(i) a monthly fixed charge to customers in portions of eastern Sussex County, Delaware, which will enable the Delaware division to extend its distribution system to provide natural gas service to these customers economically without upfront contributions from these customers;

(ii) optional service offerings to customers to facilitate conversions to natural gas, including a conversion finance service to help customers manage their cost of conversion equipment; and

(iii) a slight rate increase for all Delaware customers in order to support the additional costs associated with the administration of the proposed service offerings.

On July 3, 2012, the Delaware PSC officially opened the docket and set a period for formal interventions to be filed. On January 4, 2013, the Division of the Public Advocate (DPA) filed a motion to close the docket on the grounds that the proposed expansion service offerings should only be considered in the context of a full base rate case. On February 6, 2013, the Hearing Examiner assigned to the case issued a report recommending that the Delaware PSC deny the DPA s motion. Subsequently, the DPA, Delaware PSC staff and our Delaware division reached an agreement in principle regarding the key aspects of the application. We anticipate that the Delaware PSC will render a final decision on the matter by July 2013.

Other Matters: We also had developments in the following regulatory matter in Delaware:

On September 21, 2012, the Delaware division filed with the Delaware PSC its annual Gas Service Rate (GSR) application, seeking approval to change its GSR, effective November 1, 2012. On October 9, 2012, the Delaware PSC authorized the Delaware division to implement the GSR charges, as filed, effective November 1, 2012, on a temporary basis and subject to refund, pending the completion of a full evidentiary hearing and a final decision. An evidentiary hearing is scheduled on May 23, 2013, and a final decision by the Delaware PSC is anticipated in July 2013.

Maryland

ESG Acquisition: On September 7, 2012, we filed an application with the Maryland PSC for approval of the acquisition of the ESG operating assets and the transfer of the ESG franchises to Chesapeake (see Note 3, Acquisitions, for additional information on the ESG acquisition). In this application, we also requested the Maryland PSC to approve the overall regulatory framework we proposed for our operation in Worcester County. The proposed regulatory framework includes: (i) a request for approval of a new gas service tariff and rates applicable to natural gas and propane distribution customers in Worcester County, including the customers currently being served by ESG; (ii) a request for approval of the capacity, supply and operating agreement with ESG for the supply and storage of propane, which will be utilized to serve the ESG system customers; and (iii) a request for approval of the accounting treatment for certain purchased assets.

On April 8, 2013, the parties finalized a settlement agreement which, if accepted by the Maryland PSC, will resolve all issues in the matter. Under the settlement agreement, we will be granted approval of: (i) the ESG acquisition; (ii) the overall regulatory framework requested; and (iii) recovery of the cost of the capacity, supply and operating agreement with ESG. In addition, we will conduct a depreciation study within the first year after the acquisition, and we will file a base rate case in two and a half years for our service in Worcester County. An evidentiary hearing and public comment hearing were conducted on April 9, 2013. We anticipate a final decision in the matter by the Maryland PSC by June

2013.

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Florida

Marianna Franchise: On July 7, 2009, the City Commission of Marianna, Florida (the Marianna Commission) adopted an ordinance granting a franchise to FPU, effective February 1, 2010, for a period not to exceed 10 years for the operation and distribution and/or sale of electric energy (the Franchise Agreement). The Franchise Agreement provides that FPU will develop and implement new time-of-use (TOU) and interruptible electric power rates, or other similar rates, mutually agreeable to FPU and the City of Marianna. The Franchise Agreement further provides for the TOU and interruptible rates to be effective no later than February 17, 2011, and available to all customers within FPU s northwest division, which includes the City of Marianna. If the rates were not in effect by February 17, 2011, the City of Marianna would have the right to give notice to FPU within 180 days thereafter of its intent to exercise an option in the Franchise Agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna for the approval of the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase was approved by the Marianna Commission and by the referendum, the closing of the purchase would have had to occur within 12 months after the referendum is approved. If the City of Marianna had elected to purchase the Marianna property, the Franchise Agreement would require the City of Marianna to pay FPU the fair market value for such property as determined by three qualified appraisers. Our future financial results would be negatively affected by the loss of earnings generated by FPU from its approximately 3,000 customers in the City of Marianna.

In accordance with the terms of the Franchise Agreement, FPU developed TOU and interruptible rates, and on December 14, 2010, FPU filed a petition with the Florida PSC for authority to implement such proposed TOU and interruptible rates on or before February 17, 2011. On February 11, 2011, the Florida PSC issued an order approving FPU s petition for authority to implement the proposed TOU and interruptible rates, which became effective on February 8, 2011. The City of Marianna objected to the proposed rates and filed a petition protesting the entry of the Florida PSC s order. On January 24, 2012, the Florida PSC dismissed with prejudice the protest by the City of Marianna.

On January 26, 2011, FPU filed a petition with the Florida PSC for approval of an amendment to FPU s Generation Services Agreement entered into between FPU and Gulf Power Company (Gulf Power). The amendment provides for a reduction in the capacity demand quantity, which generates the savings necessary to support the TOU and interruptible rates approved by the Florida PSC. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019. By its order dated June 21, 2011, the Florida PSC approved the amendment. On July 12, 2011, the City of Marianna filed a protest of this decision and requested a hearing on the amendment. On January 24, 2012, the Florida PSC dismissed with prejudice the protest by the City of Marianna.

The City of Marianna filed an appeal with the Florida Supreme Court on March 7, 2012 and with the Florida PSC on March 19, 2012, seeking an appellate review of both of the decisions by the Florida PSC with respect to the protests by the City of Marianna.

As more fully disclosed in Note 6, Other Commitments and Contingencies, on March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the Franchise Agreement by FPU and seeking a declaratory judgment that the City of Marianna has the right to exercise its option to purchase FPU s property in the City of Marianna in accordance with the terms of the Franchise Agreement. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. Subsequently, FPU and the City of Marianna entered into a settlement agreement, which contemplated among other items, the City of Marianna proceeding with a referendum on the purchase of FPU s facilities. On April 9, 2013, the referendum took place and the citizens of the City of Marianna voted, by a wide margin, to reject the purchase by the City of Marianna of FPU s facilities. As a result of the outcome of the referendum and pursuant to the terms of the settlement agreement, FPU s franchise with the City of Marianna will be extended by 10 years. Also pursuant to the settlement agreement, the City of Marianna withdrew its appeals before the Florida Supreme Court of the Florida PSC s orders regarding the implementation of TOU and interruptible rates and the amendment to the Generation Services Agreement between FPU and Gulf Power.

On August 27, 2012, FPU filed a petition with the Florida PSC for approval to: (i) defer, as a regulatory asset, the litigation expenses associated with the litigation initiated by the City of Marianna; and (ii) amortize over five years, beginning in January 2013, previously expensed and future litigation expenses. On December 3, 2012, the Florida PSC issued an order approving FPU s request for deferral and amortization of the litigation expenses for regulatory accounting and reporting purposes. This order does not change the current rates charged by FPU to its electric customers unless FPU seeks and receives an approval from the Florida PSC in a future proceeding to recover the litigation expense in rates. We have not deferred the litigation expense as a regulatory asset at March 31, 2013 and December 31, 2012 in the accompanying condensed consolidated balance sheets. If we determine in the future that recovery of the litigation expenses in future rates is probable, we will establish a regulatory asset in accordance with GAAP. The total ligation expenses associated with the City of Marianna litigation were $1.6 million at March 31, 2013.

Other Matters: We also had developments in the following regulatory matters in Florida:

On August 28, 2012, Chesapeake s Florida division filed a petition with the Florida PSC for approval of a special contract with one of its customers for transportation service under its special contract service tariff. The initial term of the new special contract service is three years with provisions for extension unless either party gives notice of termination to the other party. At the December 10, 2012 agenda, the Florida PSC approved this special contract service. A final order was issued on January 25, 2013.

On September 28, 2012, FPU provided a letter to the Florida PSC stating its intent to request approval of a positive acquisition adjustment associated with FPU s purchase of the operating assets of Indiantown Gas Company (IGC) in 2010. In this letter, FPU also acknowledged the jurisdiction of the Florida PSC to calculate and dispose of prospective overearnings, if any, occurring after October 1, 2012 that may be found at the conclusion of the acquisition adjustment proceeding. On December 11, 2012, FPU filed a petition to request approval of a positive acquisition adjustment associated with FPU s purchase of IGC s assets. At this time, the Florida PSC has not scheduled an agenda date for this matter.

On December 14, 2012, Peninsula Pipeline filed a petition with the Florida PSC, asking for approval of a transportation service agreement with FPU. The agreement provides for an upstream interconnection of Peninsula Pipeline s facilities with the Florida Gas Transmission Company (FGT) system and a downstream interconnection with FPU s facilities. An agenda date for the Florida PSC to review and approve this agreement has not been set at this time.

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Eastern Shore

The following are regulatory activities involving FERC orders applicable to Eastern Shore and the expansions of Eastern Shore s transmission system:

Mainline Expansion Project: On May 14, 2012, Eastern Shore submitted to the FERC an Application for a Certificate of Public Convenience and Necessity for approval to construct, own and operate the facilities necessary to deliver additional firm service of 15,040 dekatherms per day (Dts/d) to an existing electric power generation customer and to Chesapeake s Delaware and Maryland divisions. The estimated capital cost of the project is approximately $16.3 million. The filing was publicly noticed on May 25, 2012. Two of Eastern Shore s existing customers and Chesapeake s Delaware and Maryland divisions filed motions to intervene in support of the project. One existing customer filed a motion to intervene and protest. On June 28, 2012, Eastern Shore submitted a response to the protest, and on August 31, 2012, the protesting customer filed a response to Eastern Shore s response. On October 3, 2012, the US Department of the Interior submitted comments on the FERC s environmental assessment regarding Eastern Shore s re-vegetation plan. On October 9, 2012, a non-profit organization also submitted comments on the FERC s environmental assessment, asserting that the environmental assessment was deficient and requesting the FERC to extend the comment period by 60 days. In February 2013, the FERC approved Eastern Shore s application and issued a certificate of public convenience and necessity. On March 11, 2013, Eastern Shore accepted the certificate and filed its environmental compliance plan. On March 21, 2013, the FERC issued a notice to proceed with construction.

Daleville Compressor Station Upgrade Filing: On October 12, 2012, Eastern Shore submitted to the FERC an Application for a Certificate of Public Convenience and Necessity, seeking authorization to construct, own, operate, and maintain a new gas fired compressor unit at its existing Daleville Compressor Station located in Chester County, Pennsylvania. The new compressor unit will provide 17,500 Dts/d of additional firm transportation service to two of Eastern Shore s existing customers. In this application, Eastern Shore also included a description of a second new gas fired compressor unit to be installed at the Daleville Compressor Station, which will replace the three existing compressors that serve as back-up units to existing primary compressor units. Eastern Shore also plans to replace the engine exhaust devices of the existing primary compressor units with air emissions control equipment to comply with new required environmental regulations. The replacement compressor unit and new engine exhaust devices will result in improved air emissions, reliability and flexibility on Eastern Shore s system. Eastern Shore does not need specific FERC approval to construct the replacement compressor unit or emission controls; however, Eastern Shore wants the FERC to be fully advised of these improvement efforts. The estimated capital costs of the project are approximately $12.1 million. The application was publicly noticed on October 23, 2012, and the comment period ended on November 13, 2012. Three unaffiliated entities entered timely petitions to intervene on Eastern Shore s behalf. On March 4, 2013, the FERC approved this application. Eastern Shore anticipates a completion date that will allow for service to commence utilizing the new facilities in November 2013.

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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 remedy 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, and have exposures at six former manufactured gas plant (MGP) sites. Those sites are located in Salisbury, Maryland, and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been in discussions with the Maryland Department of Environment (MDE) regarding a seventh former MGP site located in Cambridge, Maryland.

As of March 31, 2013, we had approximately $10.5 million in environmental liabilities related to all of FPU s MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates, approximately $8.9 million of which has been recovered as of March 31, 2013. We had approximately $5.1 million in regulatory assets for future recovery of environmental costs from FPU s customers.

In addition to the FPU MGP sites, we had $153,000 in environmental liabilities at March 31, 2013, related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of March 31, 2013, we had approximately $521,000 in regulatory and other assets for future recovery through Chesapeake s rates. 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 will be recoverable from customers through rates.

The following discussion provides details on MGP sites:

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated an MGP. FPU is currently implementing a remedial plan approved by the Florida Department of Environmental Protection (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. It is anticipated that similar remedial actions ultimately will 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. In January 2007, FPU and other responsible parties at the Sanford site (collectively with FPU the Sanford Group) signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the United States Environmental Protection Agency (EPA) for the site. FPU s share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of March 31, 2013, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

The total cost of the final remedy is now estimated to be over $20 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.

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As of March 31, 2013, 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 as provided in the Third Participation Agreement to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of March 31, 2013.

Key West, Florida

FPU formerly owned and operated a MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party. In 2010, after 17 years of regulatory inactivity, FDEP observed that some soil and groundwater standards were exceeded and requested implementation of additional soil and groundwater fieldwork. The scope of work is limited to the installation of two additional monitoring wells and periodic monitoring of the new and existing wells. The two new monitoring wells were installed in November 2011, and groundwater monitoring began in December 2011. The first semi-annual report from the monitoring program was issued in May 2012. The data from the June 2012 and September 2012 monitoring events were submitted to the FDEP on October 4, 2012. FDEP responded via e-mail on October 9, 2012, that based on the data, Natural Attenuation Monitoring (NAM) appears to be an appropriate remedy for the site. The FDEP issued a Remedial Action Plan approval order, dated October 12, 2012, which specified that a limited semi-annual monitoring program is to be conducted. The annual cost to conduct the limited NAM program is not expected to exceed $8,000. Although the duration of the FDEP-required limited NAM cannot be determined with certainty, it is anticipated that total costs to complete the remedial action will not exceed $50,000.

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 Florida Department of Transportation (FDOT). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action determination for the site, which must include a requirement for institutional and engineering controls. On December 13, 2011, Gulf Power, the City of Pensacola, FDOT and FPU submitted to FDEP a draft covenant for institutional and engineering controls for the site. Upon FDEP s approval and the subsequent recording of the institutional and engineering controls, no further work is expected to be required of the parties. Assuming FDEP approves the draft institutional and engineering controls, it is anticipated that FPU s share of remaining legal and cleanup costs will not exceed $5,000.

Salisbury, Maryland

We have substantially completed remediation of a site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water 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.

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. The recent groundwater sampling results show a continuing reduction in contaminant concentrations from the treatment system, which has been in operation since 2002. Currently, we predict that remedial action objectives could be met in approximately two to three years for the area being treated by the remediation system. On August 7, 2012, FDEP issued a letter discussing the need to evaluate further remedial options, which could incorporate risk-management options, including natural attenuation and the use of institutional and engineering controls. Modifications to the existing consent order and the remedial action plan modification could be required to incorporate risk-management options into the remedy for the site. If such modifications are required, we estimate that future remediation costs could be as much as $443,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site. If we are required to incur this cost, we continue to believe that the entire amount will be recoverable from customers through our approved rates.

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The current treatment system at the Winter Haven site does not address impacted soils in the southwest corner of the site. In 2010, we obtained a conditional approval from FDEP for a soil excavation plan; however, because the costs associated with shoreline stabilization and dewatering are likely to be substantial, alternatives to this excavation plan are being evaluated.

FDEP has indicated that we may be required to remediate sediments along the shoreline of Lake Shipp, immediately west of the site. Based on studies performed to date, we object to FDEP s suggestion that the sediments have been adversely impacted by the former operations of the MGP. Our early estimates indicate that some of the corrective measures discussed by FDEP could cost as much as $1.0 million. We believe that corrective measures for the sediments are not warranted and intend to oppose any requirement that we undertake corrective measures in the offshore sediments. We have not recorded a liability for sediment remediation, as the final resolution of this matter cannot be predicted at this time.

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.

We are currently investigating a potential environmental matter involving a property we recently purchased in Fernandina Beach, Florida. The extent of contamination and our cost to remediate the property, if any, cannot be determined at this time; therefore, we have not recorded an environmental liability for this site.

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6. Other Commitments and Contingencies

Litigation

On March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida. In the complaint, the City of Marianna alleged three breaches of the Franchise Agreement by FPU: (i) FPU failed to develop and implement TOU and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) mutually agreed upon TOU and interruptible rates by FPU were not effective or in effect by February 17, 2011; and (iii) FPU did not have such rates available to all of FPU s customers located within and without the corporate limits of the City of Marianna. The City of Marianna was seeking a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase was approved by the Marianna Commission and the referendum was approved by the voters, the closing of the purchase had to occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. On August 3, 2011, the City of Marianna notified FPU that it was formally exercising its option to purchase FPU s property. On August 31, 2011, FPU advised the City of Marianna that it had no right to exercise the purchase option under the Franchise Agreement and that FPU would continue to oppose the effort by the City of Marianna to purchase FPU s property. In December 2011, the City of Marianna filed a motion for summary judgment. FPU opposed the motion. On April 3, 2012, the court conducted a hearing on the City of Marianna s motion for summary judgment. The court subsequently denied in part and granted in part the City of Marianna s motion after concluding that issues of fact remained for trial with respect to each of the three alleged breaches of the Franchise Agreement. Mediation was conducted on May 11, 2012, and again on July 6, 2012, but no resolution was reached.

The case was originally scheduled for trial in October 2012; however, due to a scheduling conflict, the trial was rescheduled to February 2013. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. Subsequently, FPU and the City of Marianna entered into a settlement agreement, which contemplated, among other items, the City of Marianna proceeding with a referendum on the purchase of FPU s facilities within the City of Marianna. On April 9, 2013, the referendum took place, and the citizens of the City of Marianna voted, by a wide margin, to reject the purchase of FPU s facilities by the City of Marianna. As a result of the dismissal with prejudice of its legal action by the City of Marianna and the outcome of the referendum on the purchase of FPU s facilities, we no longer have any contingencies related to claims by the City of Marianna.

We are involved in certain other legal actions and claims arising in the normal course of business. We are also involved in certain legal proceedings 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.

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase gas, electricity and propane from various suppliers. The contracts have various expiration dates. Our Delaware and Maryland natural gas distribution operation divisions had a contract with an unaffiliated energy marketing and risk management company to manage a portion of their natural gas transportation and storage capacity, which expired on March 31, 2013. On April 1, 2013, our Delaware and Maryland divisions entered into a new contact with a different company to perform similar asset management functions. The new contract expires on March 31, 2015.

Chesapeake s Florida natural gas distribution division has firm transportation service contracts with FGT and Gulfstream Natural Gas System, LLC (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 Peninsula Energy Services Company, Inc. (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 for the service.

In May 2012, PESCO renewed contracts to purchase natural gas from various suppliers. These contracts expire in May 2013. PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements before the existing agreements expire.

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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 (formerly known as Jacksonville Electric Authority) 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) fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU s electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken or proposed to be taken to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. As of March 31, 2013, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has authorized the Company to issue corporate guarantees 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 $45.0 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which are for our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at March 31, 2013 was $30.7 million, with the guarantees expiring on various dates through February 2014.

Chesapeake 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, to the condensed consolidated financial statements 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, 2013, 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 $400,000, which expires on December 2, 2013, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for $304,000 to our former primary insurance company, which will expire on June 1, 2013. There have been no draws on these letters of credit as of March 31, 2013. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future

We provided a letter of credit for $2.3 million to Texas Eastern Transmission, LP (TETLP) related to firm transportation service agreements between our Delaware and Maryland divisions and TETLP.

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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 three operating segments:

Regulated Energy. The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission 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 natural gas marketing, propane distribution and propane wholesale marketing operations, which are unregulated as to their rates and charges for their services.

Other. The other segment consists primarily of the advanced information services operation, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

The following table presents financial information about our reportable segments.

For the Three Months Ended March 31, *(in thousands)*	**2013**	2012
Operating Revenues, Unaffiliated Customers		
Regulated Energy	**$ 81,304**	$ 72,018
Unregulated Energy	**54,991**	44,887
Other	**4,434**	4,009
Total operating revenues, unaffiliated customers	**$ 140,729**	$ 120,914
Intersegment Revenues [1]		
Regulated Energy	**$ 263**	$ 278
Unregulated Energy		
Other	**243**	235
Total intersegment revenues	**$ 506**	$ 513
Operating Income		
Regulated Energy	**$ 17,306**	$ 14,798
Unregulated Energy	**9,369**	5,154
Other and eliminations	**(125)**	121
Total operating income	**26,550**	20,073
Other income, net of other expenses	**289**	196
Interest	**2,072**	2,291
Income before income taxes	**24,767**	17,978
Income taxes	**9,898**	7,251
Net income	**$ 14,869**	$ 10,727

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

(in thousands)	**March 31, 2013**	**December 31, 2012**
Identifiable Assets		
Regulated energy	**$ 621,593**	$ 615,438
Unregulated energy	**83,743**	79,287
Other	**33,121**	39,021
Total identifiable assets	**$ 738,457**	$ 733,746

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Our operations are almost entirely domestic. Our advanced information services subsidiary, BravePoint, has infrequent transactions in foreign countries, which are denominated and paid primarily in U.S. dollars. These transactions are immaterial to the consolidated revenues.

8. Accumulated Other Comprehensive Income (Loss)

The following table presents the changes in the balance of accumulated other comprehensive income (loss). Defined benefit pension and postretirement plan items are the only component of our accumulated comprehensive income (loss). All amounts in the following table are presented net of tax.

For the three months ended March 31, *(in thousands)*	**2013**
Beginning balance	**($ 5,062)**
Other comprehensive loss before reclassifications	**(6)**
Amounts reclassified from accumulated other comprehensive loss	**55**
Net current-period other comprehensive income (loss)	**49**
Ending balance	**($ 5,013)**

The following table presents amounts reclassified out of accumulated other comprehensive loss.

For the three months ended March 31, *(in thousands)*	**2013**
Amortization of defined benefit pension and postretirement plan items:	
Net loss [1]	**(106)**
Prior service cost [1]	**14**
Total before tax	**($ 92)**
Tax benefit	**$ 37**
Net of tax	**($ 55)**

(1) These amounts are included in the computation of net periodic costs (benefits). See Note 9, Employee Benefit Plans, for additional details. Amortization of defined benefit pension and postretirement plan items are included in operations expense in the accompanying condensed consolidated statement of income. Tax benefit is included in income tax expenses in the accompanying condensed consolidated statement of income.

9. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three months ended March 31, 2013 and 2012 are set forth in the following table:

	Chesapeake Pension Plan		**FPU Pension Plan**		**Chesapeake Pension SERP**		**Chesapeake Postretirement Plan**		**FPU Medical Plan**	
For the Three Months Ended March 31,	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
(in thousands)										
Service cost	$	$	$	$	$	$	$	$	$	$ 40
Interest cost	102	125	594	639	21	23	12	15	16	45
Expected return on plan assets	(126)	(109)	(719)	(658)						
Amortization of prior service cost		(1)			5	5	(19)	(20)		
Amortization of net loss	57	85	81	44	16	11	18	18		23
Net periodic cost (benefit)	33	100	(44)	25	42	39	11	13	16	108
Amortization of pre-merger regulatory asset			190	190					2	2
Total periodic cost	$ 33	$ 100	$ 146	$ 215	$ 42	$ 39	$ 11	$ 13	$ 18	$ 110

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We expect to record pension and postretirement benefit costs of approximately $999,000 for 2013. Included in the $999,000 pension and postretirement benefit costs for 2013 is $769,000 related to continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU s regulated energy operations of the changes in funded status that occurred but were not recognized as part of net periodic benefit costs prior to the merger. This was deferred as a regulatory asset by FPU prior to the merger to be recovered through rates pursuant to a previous order by the Florida PSC. The unamortized balance of this regulatory asset was $5.0 million and $5.2 million at March 31, 2013 and December 31, 2012, respectively.

FPU continues to record as a regulatory asset a portion of the unrecognized pension and postretirement benefit costs related to its regulated operations after the merger pursuant to a Florida PSC order. The portion of the unrecognized pension and postretirement benefit costs related to FPU s unregulated operations and Chesapeake s operations is recorded to accumulated other comprehensive income/loss. The following table presents the amounts included in the regulatory asset and accumulated other comprehensive income/loss that were recognized as components of net periodic benefit cost during the three months ended March 31, 2013:

(in thousands)	**Chesapeake Pension Plan**	**FPU Pension Plan**	**Chesapeake SERP**	**Chesapeake Postretirement Plan**	**FPU Medical Plan**	**Total**
Prior service cost (credit)	$	$	$ 5	($ 19)	$	($ 14)
Net loss	57	81	16	18		172
Total recognized in net periodic benefit cost	$ 57	$ 81	$ 21	($ 1)	$	$ 158
Recognized from accumulated other comprehensive loss [1]	$ 57	$ 15	$ 21	($ 1)	$	$ 92
Recognized from regulatory asset		66				66
Total	$ 57	$ 81	$ 21	($ 1)	$	$ 158

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

We expect to contribute $364,000 and $842,000 to the Chesapeake and FPU pension plans, respectively, during the year 2013, representing minimum contribution payments required in 2013.

The Chesapeake Pension Supplemental Executive Retirement Plan (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 Pension SERP for the three months ended March 31, 2013, were $22,000; we expect to pay total cash benefits of approximately $88,000 in 2013. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three months ended March 31, 2013, totaled $22,000 and we have estimated that approximately $97,000 will be paid for such benefits in 2013. Cash benefits paid for the FPU Medical Plan, primarily for medical claims for the three months ended March 31, 2013, totaled $27,000. We estimate that approximately $258,000 will be paid for such benefits in 2013.

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10. Investments

The investment balances at March 31, 2013 and December 31, 2012, consist of the following:

(in thousands)	March 31, 2013	December 31, 2012
Rabbi trust (associated with Supplemental Executive Retirement Savings Plan)	**$ 2,270**	$ 2,116
Rabbi trust (associated with certain director s compensation)	**41**	39
Investments in equity securities	**2,215**	2,013
Total	**$ 4,526**	$ 4,168

We classify these investments as trading securities and report them at their fair value. For the three months ended March 31, 2013 and 2012, we recorded net unrealized gains of $283,000 and $317,000, respectively, in other income in the condensed consolidated statements of income related to these investments. We also have recorded an associated liability, which is included in other pension and benefit costs in the condensed consolidated balance sheets and is adjusted each month for the gains and losses incurred by the Rabbi Trusts.

11. Share-Based Compensation

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan (DSCP) and our Performance Incentive Plan (PIP), respectively. 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 each award on the date it was granted.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the DSCP and the PIP for the three months ended March 31, 2013 and 2012:

For the Three Months Ended March 31, *(in thousands)*	2013	2012
Directors Stock Compensation Plan	**$ 111**	$ 111
Performance Incentive Plan	**270**	234
Total compensation expense	**381**	345
Less: tax benefit	**153**	138
Share-Based Compensation amounts included in net income	**$ 228**	$ 207

<u>Directors Stock Compensation Plan</u>

Shares granted under the DSCP are issued in advance of the directors service periods and are fully vested as of the date of the grant. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. At March 31, 2013, there was $37,000 of unrecognized compensation expense related to the DSCP awards. This expense is expected to be recognized over the directors remaining service period ending April 30, 2013.

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Performance Incentive Plan

The table below presents the summary of the stock activity for the PIP for the three months ended March 31, 2013:

	Number of Shares	Weighted Average Fair Value
Outstanding December 31, 2012	84,645	$ 37.86
Granted	23,491	$ 44.97
Vested	24,332	$ 33.26
Expired	3,043	$ 39.12
Outstanding March 31, 2013	80,761	$ 42.14

In January 2013, the Board of Directors granted awards under the PIP for 23,491 shares. The shares granted in January 2013 are multi-year awards that will vest at the end of the three-year service period, or December 31, 2015. These awards are earned based upon the successful achievement of long-term goals, growth and financial results, which are comprised of both market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the date each award is granted. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

At March 31, 2013, the aggregate intrinsic value of the PIP awards was $4.0 million.

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 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 in order to mitigate the impact of wholesale price fluctuations. As of March 31, 2013, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

In May 2012, our propane distribution operation entered into call options to protect against an increase in propane prices associated with 1,260,000 gallons purchased for the propane price cap program for December 2012 through March 2013. The call options would have been exercised if the propane prices had risen above the strike prices, which ranged from $0.905 per gallon to $0.990 per gallon during this four-month period. We would have received the difference between the market price and the strike price during those months. We paid $139,000 to purchase the call options. The call options expired without exercise as the market prices were below the strike prices. We accounted for these call options as a fair value hedge. There was no ineffective portion of this fair value hedge.

Xeron, Inc. (Xeron), our propane wholesale and marketing subsidiary, 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 the mark-to-market method of accounting, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income in the period of change. As of March 31, 2013, we had the following outstanding trading contracts which we accounted for as derivatives:

At March 31, 2013	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	2,522,000	$ .08275 $.09800	$ 0.9190
Purchase	2,522,000	$ 0.8250 $1.3176	$ 0.8941

Estimated market prices and weighted average contract prices are in dollars per gallon.

All contracts expire by the end of the fourth quarter of 2013.

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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 its outstanding accounts receivable and payable by the same counterparties. Receivables and payables with these two counterparties are presented on a gross basis in the accompanying condensed consolidated balance sheets. At March 31, 2013, Xeron had a right to offset $0 and $553,000 of accounts receivable and accounts payable, respectively, with these two counterparties. At December 31, 2012, Xeron had a right to offset $1,225,000 and $511,000 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.

Fair values of the derivative contracts recorded in the condensed consolidated balance sheet as of March 31, 2013 and December 31, 2012, are as follows:

	Asset Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**March 31, 2013**	**December 31, 2012**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	**$ 150**	$ 182
Derivatives designated as fair value hedges			
Call options (1)	Mark-to-market energy assets		28
Total asset derivatives		**$ 150**	$ 210

	Liability Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**March 31, 2013**	**December 31, 2012**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ 85**	$ 331
Total liability derivatives		**$ 85**	$ 331

(1) We purchased call options for the propane price cap program in May 2012. The call options expired in March 2013.

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

(in thousands)	Location of Gain (Loss) on Derivatives	Amount of Gain (Loss) on Derivatives: For the Three Months Ended March 31, 2013	2012
Derivatives not designated as hedging instruments:			
Unrealized gain (loss) on forward contracts	Revenue	**$ 214**	($ 60)
Derivatives designated as fair value hedges:			
Put/Call Option	Cost of sales	**(28)**	27
Total		**$ 186**	$ (33)

The effects of trading activities on the condensed consolidated statements of income are the following:

(in thousands)	Location in the Statement of Income	Three months ended March 31, 2013	2012
Realized gain on forward contracts and options	Revenue	**$ 74**	$ 514
Unrealized gain (loss) on forward contracts	Revenue	**214**	(60)
Total		**$ 288**	$ 454

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).

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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 used at March 31, 2013 and December 31, 2012:

March 31, 2013 *(in thousands)*	**Fair Value**	**Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments equity securities	$ 1,742	$ 1,742	$	$
Investments guaranteed income fund	$ 398	$	$	$ 398
Investments other	$ 2,386	$ 2,386	$	$
Mark-to-market energy assets	$ 150	$	$ 150	$
Liabilities:				
Mark-to-market energy liabilities	$ 85	$	$ 85	$

December 31, 2012 *(in thousands)*	**Fair Value**	**Fair Value Measurements Using: Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments equity securities	$ 2,007	$ 2,007	$	$
Investments other	$ 2,161	$ 2,161	$	$
Mark-to-market energy assets, including call options	$ 210	$	$ 210	$
Liabilities:				
Mark-to-market energy liabilities	$ 331	$	$ 331	$

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the three months ended March 31, 2013:

At March 31, *(in thousands)*	**2013**
Beginning Balance	**$**
Transfers in due to change in trustee	**425**
Purchases and adjustments	**(13)**
Transfers	**(16)**
Investment Income	**2**
Ending Balance	**$ 398**

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The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of March 31, 2013 and December 31, 2012:

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 over the counter (OTC) markets.

Propane put/call option The fair value of the propane put option is 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.

At March 31, 2013, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

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

At March 31, 2013, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $110.0 million, compared to a fair value of $129.1 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, and risk profile. At December 31, 2012, long-term debt, including the current maturities, had a carrying value of $110.1 million, compared to the estimated fair value of $133.2 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

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14. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	March 31, 2013	December 31, 2012
FPU secured first mortgage bonds [(A)]:		
9.57% bond, due May 1, 2018	**$ 5,445**	$ 5,444
10.03% bond, due May 1, 2018	**2,994**	2,994
9.08% bond, due June 1, 2022	**7,963**	7,962
Uncollateralized senior notes:		
7.83% note, due January 1, 2015	**4,000**	4,000
6.64% note, due October 31, 2017	**13,636**	13,636
5.50% note, due October 12, 2020	**16,000**	16,000
5.93% note, due October 31, 2023	**30,000**	30,000
5.68% note, due June 30, 2026	**29,000**	29,000
Convertible debentures:		
8.25% due March 1, 2014	**897**	942
Promissory note	**110**	125
Total long-term debt	**110,045**	110,103
Less: current maturities	**(9,093)**	(8,196)
Total long-term debt, net of current maturities	**$ 100,952**	$ 101,907

(A) FPU secured first mortgage bonds are guaranteed by Chesapeake.

In June 2010, we entered into an agreement with Metropolitan Life Insurance Company and New England Life Insurance Company to issue up to $36.0 million in Chesapeake s unsecured senior notes. In June 2011, we issued $29.0 million of 5.68 percent unsecured senior notes to permanently finance the redemption of two series of FPU first mortgage bonds in 2010. On May 2, 2013, we issued an additional $7.0 million of 6.43 percent unsecured senior notes under the same agreement. These notes have similar covenants and default provisions as the senior notes issued in June 2011. Proceeds from these notes will be used to finance the redemption of the 9.57 percent and 10.03 percent series of FPU s first mortgage bonds, which is expected in May 2013.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

Management s Discussion and Analysis of Financial Condition and Results of Operations is designed to provide a reader of the financial statements with a narrative report on our financial condition, results of operations and liquidity. This discussion and analysis should be read in conjunction with the attached unaudited condensed consolidated financial statements and notes thereto and our Annual Report on Form 10-K for the year ended December 31, 2012, 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, c potential, forecast or other similar words, or future or conditional verbs such as may, will, should, would or could. These statements re 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 that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries (including deregulation);

the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recovered in rates;

the loss of customers due to government-mandated sale of our utility distribution facilities;

industrial, commercial and residential growth or contraction in our markets or service territories;

the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;

the timing and extent of changes in commodity prices and interest rates;

general economic conditions, including any potential effects arising from terrorist attacks and any consequential hostilities or other hostilities or other external factors over which we have no control;

changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now or may in the future own or operate;

the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;

declines in the value of the pension plan assets and resultant cash funding requirements for our defined benefit pension plans;

the creditworthiness of counterparties with which we are engaged in transactions;

the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;

the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;

conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;

the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;

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- 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
- changes in technology affecting our advanced information services business.

Introduction

We are a diversified utility company engaged, directly or through subsidiaries, in regulated energy businesses, unregulated energy businesses, and other unregulated businesses, including advanced information services.

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 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;
- empowering and energizing our employees at all levels to work in unison to achieve our strategy;

- engaging our local communities and government in a cooperative and mutually beneficial way;
- maintaining a capital structure that enables us to access capital as needed;
- maintaining a consistent and competitive dividend for shareholders; and
- creating and maintaining a diversified customer base, energy portfolio and utility foundation.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is normally highest due to colder temperatures.

The following discussions and those later 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 are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by the Company under its allowed rates for regulated energy operations and under its competitive pricing structure for unregulated natural gas marketing and propane distribution operations. Our management uses gross margin in measuring our business units performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

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Results of Operations for the Quarter Ended March 31, 2013

Overview and Highlights

Our net income for the quarter ended March 31, 2013 was $14.9 million, or $1.54 per share (diluted). This represents an increase of $4.1 million, or $0.43 per share (diluted), compared to a net income of $10.7 million, or $1.11 per share (diluted), as reported for the same quarter in 2012.

For the Three Months Ended March 31, *(in thousands except per share)*	**2013**	**2012**	**Increase (decrease)**
Business Segment:			
Regulated Energy	**$ 17,306**	$ 14,798	$ 2,508
Unregulated Energy	**9,369**	5,154	4,215
Other	**(125)**	121	(246)
Operating Income	**26,550**	20,073	6,477
Other Income	**289**	196	93
Interest Charges	**2,072**	2,291	(219)
Income Taxes	**9,898**	7,251	2,647
Net Income	**$ 14,869**	$ 10,727	$ 4,142
Earnings Per Share of Common Stock			
Basic	**$ 1.55**	$ 1.12	$ 0.43
Diluted	**$ 1.54**	$ 1.11	$ 0.43

Key variances include:

(in thousands, except per share)	**Pre-tax Income**	**Net Income**	**Earnings Per Share**
First Quarter of 2012 Reported Results	$ 17,978	$ 10,727	$ 1.11
Adjusting for unusual items:			
Weather impact (due primarily to significantly warmer-than-normal weather in 2012)	3,237	1,931	0.20
	3,237	1,931	0.20
Increased Margins:			
Natural gas growth	1,595	952	0.10
Higher propane retail margins per gallon	2,119	1,264	0.13
Propane other volume increase	811	484	0.05
	4,525	2,700	0.28
Increased Other Operating Expenses:			
Payroll and benefits costs	(529)	(316)	(0.03)
Higher depreciation, asset removal and facilities costs	(461)	(275)	(0.03)
	(990)	(591)	(0.06)
Net Other Changes	17	102	0.01

First Quarter of 2013 Reported Results	$ 24,767	$ 14,869	$ 1.54

Our results in the first quarter of 2013 reflected additional gross margin generated by: (a) colder temperatures on the Delmarva Peninsula and in Florida during the first quarter of 2013, compared to the same quarter in 2012; (b) additional services and customer growth in the natural gas transmission and distribution operations as a result of major expansion initiatives completed in 2012 in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Nassau County, Florida; and (c) strong retail propane margins per gallon through the first quarter of 2013, as the decline in propane costs in late 2012 and early 2013 outpaced the slight decline in retail prices driven by competition and other market conditions. These increases in gross margin were partially offset by increased payroll and benefits costs and higher expenses associated with growth initiatives and capital expenditures to support growth and system integrity.

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The following is a summary of key factors affecting our businesses and their impacts on our results during the current and future periods.

Growth

We continue to see growth in our natural gas businesses from our efforts over the past several years to expand our services by delivering clean-burning, environmentally friendly natural gas to customers. We are continuing to pursue additional opportunities in an effort to sustain growth over the next several years.

New natural gas transmission services and growth in natural gas distribution customers generated $880,000 and $715,000, respectively, in additional gross margin. These increases in gross margin were related primarily to expansion of natural gas service to new areas and conversion of several large commercial and industrial customers to natural gas service during 2012.

Major Service Expansions and Customer Growth Reflected in Results

In 2012 and January 2013, we expanded natural gas transmission and distribution services to Sussex County, Delaware and Nassau County, Florida and also initiated natural gas transmission service in Worcester and Cecil Counties, Maryland. These major service expansions increased our natural gas footprint, delivering natural gas service to areas where it was not previously available. These initiatives generated $746,000 of additional gross margin for the natural gas transmission operations in the first quarter of 2013. Natural gas distribution service to two industrial facilities of an existing customer in southeastern Sussex County, Delaware generated $48,000 of additional gross margin in the first quarter of 2013. The following table summarizes our major expansion initiatives that have already commenced:

Major Service Expansions Initiated in 2012 and 2013 (dollars in thousands):

Project	Date of New Service	Q1 2013 Margin	Estimated 2013 Margin	Total 2012 Margin
Sussex County, DE expansion				
Transmission (for southeastern part) 1,550 Dts/d[1]	Mar-12 to May-12	$ 112	$ 446	$ 334
Distribution Two facilities of an existing customer in the southeastern part of Sussex County [2]	Mar-12 to Aug-12	52	151	89
		$ 164	$ 597	$ 423
Cecil County, MD expansion				
Transmission 4,070 Dts/d	Nov-12	$ 220	$ 882	$ 147
Worcester County, MD expansion				
Transmission 1,450 Dts/d	Jun-12 to Jan-13	$ 98	$ 391	$ 90
Nassau County, FL expansion				
Transmission A new fixed annual rate service	Apr-12	$ 332	$ 1,300	$ 1,537
		$ 814	$ 3,170	$ 2,197
Total by Geographic Location of the Project:				
Delmarva Natural Gas Distribution		$ 52	$ 151	$ 89
Delmarva Natural Gas Transmission		430	1,719	571
Florida Natural Gas Transmission		332	1,300	1,537
		$ 814	$ 3,170	$ 2,197

(1) These services generated $16,000 in gross margin in the first quarter of 2012.
(2) These services generated $4,000 in gross margin in the first quarter of 2012.

In addition to these service expansions, the Delmarva natural gas distribution operation has generated $192,000 in additional gross margin in the first quarter of 2013, over the first quarter of 2012, primarily from an increase in the number of residential customers served. Customer growth in Florida, primarily from commercial and industrial customers, generated $475,000 in additional gross margin during the first quarter of 2013.

Future Major Expansion Initiatives and Opportunities

Although not affecting results in the first quarter of 2013, Eastern Shore has entered into precedent agreements with NRG Energy Center Dover LLC (NRG) and PBF Energy Inc. (Delaware City Refinery) to further expand its transmission system in order to provide additional services to these customers. Eastern Shore expects to enter into firm transportation service agreements with NRG and Delaware City Refinery upon satisfaction of certain conditions pursuant to the respective precedent agreements. In March 2013, the FERC approved the construction of the new facilities necessary to provide these additional services, which are expected to be initiated in late 2013. Once the facilities are constructed for the NRG plant, the additional services will generate $2.4 million to $2.8 million of additional gross margin on an annualized basis. Once the additional facilities to serve the Delaware City Refinery are constructed, the incremental service is expected to generate annualized gross margin of $1.6 million. This new contract with the Delaware City Refinery replaces the 10,000 Dts/d contract that expired in November 2012. Eastern Shore provided additional interruptible service for the first quarter of 2013, which generated $265,000 of additional gross margin; this interruptible service will be partially displaced with the 5,000 Dts/d contract that has been executed for $264,000 of gross margin for service from May 2013 to October 2013 and then ultimately with the new 15,000 Dts/d contract that begins in December 2013.

In Florida, Peninsula Pipeline, our intrastate natural gas transmission subsidiary, entered into a firm transportation agreement with an unaffiliated utility, which will generate estimated annual gross margin of approximately $840,000. This service is expected to commence in the second quarter of 2013 upon completion of the construction of a new natural gas transmission pipeline.

The following table summarizes our future major expansion initiatives and opportunities:

Upcoming Major Expansion Initiatives with Executed Contracts (dollars in thousands):

Project	Estimated Date of New Service	Estimated 2013 Margin	Estimated Annualized Margin
Service to an unaffiliated Florida utility (1)	Starting in Jun-13	$490	$840
Service to NRG s Dover, DE electric generation plant			
Short-term contract 13,440 Dts/d (2)	From May-13 to Oct-13	$1,158	N/A
Transmission 13,440 Dts/d (3)	Starting in Nov-13	$400 to $467	$2,400 to $2,800
Delaware City refinery expansion			
Short-term contract 5,000 Dts/d (2)	From May-13 to Oct-13	$264	N/A
Transmission 15,000 Dts/d (3) (4)	Starting in Dec-13	$133	$1,600
		$2,445 to $2,512	$4,840 to $5,240

(1) Estimated annual margin is based on a fixed monthly reservation charge agreed to by the customer.

(2) Prior to commencing the new service using new facilities, Eastern Shore agreed to provide a short-term service utilizing the existing system capacity from May 2013 to October 2013. During the first quarter of 2013, Eastern Shore provided interruptible service to the Delaware City Refinery that generated $265,000 in additional gross margin.

(3) A precedent agreement has been entered into by the parties for these services. The figures provided represent the estimated gross margin pursuant to the respective precedent agreement. A firm transportation service agreement will be entered into by the parties upon satisfying certain conditions.

(4) This contract is expected to replace the 10,000 Dts/d contract with annualized gross margin of $1.1 million, which expired in November 2012.

As we expand our natural gas service to new areas, initially through transmission and distribution service to large industrial customers, our natural gas distribution operations continue to pursue additional opportunities to provide service to residential and other commercial and industrial customers in those areas. In an effort to increase the availability of natural gas within our Delaware service areas, the Company s

Delaware natural gas distribution division filed an application with the Delaware PSC in June 2012 to add several natural gas expansion service offerings. These offerings include a monthly fixed charge in lieu of upfront contributions from customers to extend the distribution system and optional service offerings to assist customers in the process of converting to natural gas. The goal of these new offerings is to meet the energy needs of residents, communities and businesses throughout our service territory, including areas of southeastern Sussex County. We have made progress towards resolving the key aspects of this application and expect the Delaware PSC to render a final decision by July 2013.

Acquisition

In June 2012, we entered into an agreement with ESG, to purchase their operating assets for approximately $16.5 million. These assets are currently used to provide propane distribution service to approximately 11,000 residential and commercial customers in Worcester County, Maryland, primarily through underground propane gas distribution systems. We are evaluating the potential conversion of some of these systems to natural gas where such conversion is economical and feasible. We filed an application with the Maryland PSC for approval of the acquisition in August 2012. On April 8, 2013, we reached a settlement, which, if accepted by the Maryland PSC, will approve the ESG acquisition, the overall regulatory framework to provide service in Worcester County, Maryland and recovery of propane supply and capacity costs through the purchased gas cost mechanism. The acquisition is also subject to obtaining consents from certain local jurisdictions to the assignment of certain franchise agreements and the satisfaction of other closing conditions. The acquisition is expected to be completed in mid-2013. We expect to finance the acquisition using unsecured short-term debt. The acquisition is expected to be accretive to earnings per share in the first full year of operations.

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Investing in Growth

We continue to expand our resources and capabilities to support growth. Our Delmarva natural gas distribution operation is in the early stages of natural gas distribution expansions in Sussex County, Delaware, and Worcester and Cecil Counties, Maryland. These expansions will require not only the construction or conversion of distribution facilities, but also the conversion of customers appliances or equipment inside their homes. We have begun the process of reorganizing our Delmarva natural gas distribution operation and expect to increase our staffing to support these expansions. Eastern Shore is currently working on construction of new facilities to provide additional services to NRG and the Delaware City Refinery as well as developing other opportunities to further expand its transmission system to provide additional service. As Eastern Shore continues to expand its facilities and service, Eastern Shore also expects to increase its staffing. Finally, to increase our overall capabilities to move these initiatives forward, resources have been, and continue to be, added in several key functional areas, including, but not limited to, Human Resources, Communications and Strategic Business Development. We expect to incur additional costs to build the stronger infrastructure we need to support our customers and future growth.

Weather and Consumption

Weather affects customer energy consumption, especially the consumption by residential and commercial customers during the peak heating and cooling seasons. Natural gas, electricity and propane are all used for heating in our service territories, and we use heating degree-days (HDD) to analyze the weather impact. Only electricity is used for cooling and we use cooling degree-days (CDD) to analyze the weather impact. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am) falls above or below 65 degrees Fahrenheit. Each degree of temperature above or below 65 degrees Fahrenheit is counted as one CDD or one HDD. We use 10-year historical averages to define normal weather for this analysis.

Weather on the Delmarva Peninsula in the first quarter of 2013 was one percent (30 HDD) colder than normal. Weather in Florida in the first quarter of 2013 was 13 percent (73 HDD) warmer than normal. Compared to weather in the first quarter of 2012, which was the warmest first quarter in the past 10 years, temperatures in the first quarter of 2013 on the Delmarva Peninsula and in Florida were 28 percent (527 HDD) and 40 percent (133 HDD) colder. Higher energy consumption as a result of colder temperatures in the first quarter of 2013, compared to temperatures in the same quarter in 2012, generated additional gross margin of $3.2 million in our natural gas, electric and propane distribution operations.

An increase in propane sales to bulk-delivery customers not attributable to weather generated additional gross margin of $391,000 in the first quarter of 2013, compared to the same quarter of 2012. The timing of propane bulk deliveries contributed to this increase.

Propane Retail Margins per Gallon

Propane prices affect both retail and wholesale marketing margins. Our propane distribution operation usually benefits from rising propane prices by selling propane to its customers based upon higher wholesale prices, while its average cost of inventory trails behind. Retail prices generally take into account replacement cost, along with other factors, such as competition and market conditions. When wholesale prices (replacement costs) increase, retail prices generally increase, and our margins expand until the current wholesale price is fully reflected in the average cost of inventory. The opposite occurs when propane prices decline. Our propane wholesale marketing operation benefits from price volatility in the propane wholesale market by entering into trading transactions.

During the first quarter of 2013, our propane distribution operations generated additional gross margin of $2.1 million due to higher retail margins per gallon, compared to the same quarter in 2012. Retail margins remained strong through the first quarter of 2013, as the 27-percent decline in our propane costs from lower propane wholesale prices in late 2012 and early 2013 outpaced the slight decline in retail prices. The propane retail price per gallon is subject to various market conditions, including competition with other propane suppliers and the availability and price of alternative energy sources, and may fluctuate based on changes in demand, supply and other energy commodity prices.

The following section provides a more detailed analysis of our results by segment.

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Regulated Energy

For the Three Months Ended March 31, *(in thousands, except degree-day and customer information)*	2013	2012	Increase (decrease)
Revenue	**$ 81,567**	$ 72,296	$ 9,271
Cost of sales	**41,616**	35,672	5,944
Gross margin	**39,951**	36,624	3,327
Operations & maintenance	**15,468**	14,854	614
Depreciation & amortization	**4,809**	4,810	(1)
Other taxes	**2,368**	2,162	206
Other operating expenses	**22,645**	21,826	819
Operating Income	**$ 17,306**	$ 14,798	$ 2,508
Weather and Customer Analysis			
Delmarva Peninsula			
HDD:			
Actual	**2,407**	1,880	527
10-year average	**2,377**	2,376	1
Estimated gross margin per HDD	**$ 1,712**	$ 2,064	($ 352)
Per residential customer added:			
Estimated gross margin	**$ 375**	$ 375	$ 0
Estimated other operating expenses	**$ 116**	$ 113	$ 3
Florida			
HDD:			
Actual	**468**	335	133
10-year average	**541**	559	(18)
Cooling degree-days:			
Actual	**81**	185	(104)
10-year average	**75**	67	8
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	**51,241**	50,174	1,067
Florida natural gas distribution	**63,139**	62,252	887
Florida electric distribution	**23,667**	23,615	52
Total	**138,047**	136,041	2,006

Operating income for the regulated energy segment for the three months ended March 31, 2013 was $17.3 million, an increase of $2.5 million, or 17 percent, compared to the same quarter in 2012. An increase in gross margin of $3.3 million was partially offset by an increase in other operating expenses of $819,000.

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Gross Margin

Gross margin for our regulated energy segment increased by $3.3 million, or nine percent, in the first quarter of 2013, compared to the same quarter in 2012. Items contributing to the quarter-over-quarter increase in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended March 31, 2012	$ 36,624
Factors contributing to the gross margin increase for the three months ended March 31, 2013:	
Customer growth	1,595
Increased customer consumption weather and other	1,580
Other	152
Gross margin for the three months ended March 31, 2013	$ 39,951

Increased Customer Consumption Weather and Other

Colder temperatures on the Delmarva Peninsula and in Florida during the first quarter of 2013, compared to the same quarter in 2012, increased gross margin by approximately $1.2 million. Increases in customer consumption beyond the estimated weather impact, particularly in Delaware and Maryland, generated $409,000 in additional gross margin.

Customer Growth

Major expansion initiatives completed in 2012 in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Nassau County, Florida generated $794,000 in additional gross margin in the first quarter of 2013, compared to the same quarter in 2012.

Our Florida natural gas distribution operation generated $475,000 of additional gross margin in the first quarter of 2013, compared to the same quarter in 2012, due primarily to a three-percent growth in commercial and industrial customers.

Two-percent residential customer growth and other growth in commercial and industrial customers in our Delmarva natural gas distribution operation generated $192,000 of additional gross margin in the first quarter of 2013, compared to the same quarter in 2012.

Eastern Shore generated $134,000 in additional gross margin as a result of increased transmission service commenced in late 2012 and higher interruptible service during the current quarter, net of an expired contract in late 2012.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $819,000, or four percent, in the first quarter of 2013, compared to the same quarter in 2012, due primarily to $502,000 in higher depreciation expense, asset removal costs and property taxes associated with capital expenditures to support growth and maintain system integrity.

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Unregulated Energy

For the Three Months Ended March 31, *(in thousands, except degree-day data)*	**2013**	**2012**	**Increase (decrease)**
Revenue	**$ 54,991**	$ 44,887	$ 10,104
Cost of sales	**37,807**	32,724	5,083
Gross margin	**17,184**	12,163	5,021
Operations & maintenance	**6,387**	5,684	703
Depreciation & amortization	**900**	838	62
Other taxes	**528**	487	41
Other operating expenses	**7,815**	7,009	806
Operating Income	**$ 9,369**	$ 5,154	$ 4,215
Weather Analysis Delmarva Peninsula			
Actual HDD	**2,407**	1,880	527
10-year average HDD	**2,377**	2,376	1
Estimated gross margin per HDD	**$ 2,882**	$ 2,869	$ 13

Operating income for the unregulated energy segment for the three months ended March 31, 2013 was $9.4 million, an increase of $4.2 million, or 82 percent, compared to the same quarter in 2012. An increase in gross margin of $5.0 million was partially offset by an increase in other operating expense of $806,000.

Gross Margin

Gross margin for our unregulated energy segment increased by $5.0 million, or 41 percent, in the first quarter of 2013, compared to the same quarter in 2012. Items contributing to the quarter-over-quarter increase in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended March 31, 2012	$ 12,163
Factors contributing to the gross margin increase for the three months ended March 31, 2013:	
Increased customer consumption weather and other	2,878
Increase in retail margins per gallon	2,119
Other	24
Gross margin for the three months ended March 31, 2013	$ 17,184

Increased Customer Consumption Weather and Other

Colder weather during the first quarter of 2013, compared to the same quarter in 2012, increased gross margin by $2.1 million. An additional increase in customer consumption due to the timing of deliveries to bulk-delivery customers on the Delmarva Peninsula, partially offset by a decline in non-weather-related Florida customer consumption, generated $391,000 of additional gross margin in the first quarter of 2013, compared to the same quarter in 2012.

As a result of the acquisition of the operating assets of Glades in February 2013, our Florida propane distribution operation added 3,000 residential and commercial propane customers and generated $220,000 of additional gross margin.

An increase in wholesale propane sales generated $200,000 of additional gross margin in the first quarter of 2013, compared to the same quarter in 2012.

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Increase in Retail Margins per Gallon

Higher retail margins per gallon in the Delmarva and Florida propane distribution operation generated $1.8 million and $300,000, respectively, of additional gross margin in the first quarter of 2013, compared to the same quarter in 2012. Retail margins remained strong through the first quarter of 2013, as the 27-percent decline in propane inventory costs from lower propane wholesale prices in late 2012 and early 2013 outpaced the slight decline in retail prices. The propane retail price per gallon is subject to various market conditions, including competition with other propane suppliers and the availability and price of alternative energy sources, and may fluctuate based on changes in demand, supply and other energy commodity prices.

Other Operating Expenses

Other operating expenses for the unregulated energy segment increased by $806,000, or 11 percent, in the first quarter of 2013, compared to the same quarter in 2012, due primarily to a higher accrual for incentive bonuses as a result of the first quarter s performance and increased costs related to propane tank and other maintenance activities.

Other

For the Three Months Ended March 31, *(in thousands)*	**2013**	**2012**	**Increase (decrease)**
Revenue	**$ 4,171**	$ 3,731	$ 440
Cost of sales	**2,282**	1,869	413
Gross margin	**1,889**	1,862	27
Operations & maintenance	**1,621**	1,393	228
Depreciation & amortization	**111**	113	(2)
Other taxes	**282**	235	47
Other operating expenses	**2,014**	1,741	273
Operating Income Other	**(125)**	121	(246)
Operating Income Eliminations			
Operating Income	**($ 125)**	$ 121	($ 246)

Note: Eliminations are entries required to eliminate activities between business segments from the consolidated results.

The other segment, which is comprised primarily of BravePoint®, Inc. (BravePoint), our advanced information services subsidiary, reported an operating loss of $125,000 in the first quarter of 2013, compared to operating income of $121,000 in the same quarter in 2012.

Gross margin

Gross margin of our other segment was $1.9 million for both the first quarters of 2013 and 2012.

Other Operating expenses

Other operating expenses for our other segment increased by $273,000 in the first quarter of 2013, compared to the same quarter in 2012, due primarily to higher payroll and related costs associated with BravePoint.

Interest Charges

Interest charges for the three months ended March 31, 2013 decreased by approximately $219,000, or 10 percent, compared to the same quarter in 2012. The decrease in interest charges is attributable primarily to decreases of $151,000 in other long-term interest expense due to scheduled repayments and $154,000 in interest on deposits from FPU s customers due to a lower interest rate on those deposits. These decreases were partially offset by an increase of $89,000 in short-term interest expense due to higher borrowings in 2013.

Income Taxes

Income tax expense was $9.9 million in the first quarter of 2013, compared to $7.3 million in the same quarter in 2012. The increase in income tax expense was due to higher taxable income. Our effective income tax rate was 40.0 percent and 40.3 percent for the first quarter of 2013 and 2012, respectively.

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Financial Position, Liquidity and Capital Resources

Our capital requirements reflect the capital-intensive and seasonal nature of our business and are principally attributable to investment in new plant and equipment, retirement of outstanding debt and seasonal variability in working capital. We rely on cash generated from operations, short-term borrowings, and other sources to meet normal working capital requirements and to finance capital expenditures.

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

Capital expenditures, which are our investments in new or acquired plant and equipment, are our largest capital requirements. We budgeted $112.3 million for capital expenditures during 2013. The following table shows the 2013 capital expenditure budget by segment:

(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$ 66,900
Natural gas transmission	28,609
Electric distribution	5,131
Total Regulated Energy	100,640
Unregulated Energy:	
Propane distribution	3,837
Other unregulated energy	1,400
Total Unregulated Energy	5,237
Other	
Advanced information services	473
Other	5,985
Total Other	6,458
Total 2013 capital expenditures	$ 112,335

We expect to fund the 2013 capital expenditures program from short-term borrowings, cash provided by operating activities, and other sources. The capital expenditures program is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts.

Included in the 2013 capital expenditure projection is approximately $16.5 million of the purchase price for our agreement with ESG to purchase its propane distribution assets that serve approximately 11,000 residential and commercial customers in Worcester County, Maryland, primarily through underground propane gas distribution systems. The purchase price is subject to certain adjustments as specified in the agreement. We expect to finance the purchase of these assets using unsecured short-term debt. The transaction is expected to be completed in mid-2013.

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, will enable us to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of March 31, 2013 and December 31, 2012:

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(in thousands)	March 31, 2013		December 31, 2012	
Long-term debt, net of current maturities	**$ 100,952**	**27%**	$ 101,907	28%
Stockholders equity	**267,772**	**73%**	256,598	72%
Total capitalization, excluding short-term debt	**$ 368,724**	**100%**	$ 358,505	100%

(in thousands)	March 31, 2013		December 31, 2012	
Short-term debt	**$ 47,635**	**11%**	$ 61,199	14%
Long-term debt, including current maturities	**110,045**	**26%**	110,103	26%
Stockholders equity	**267,772**	**63%**	256,598	60%
Total capitalization, including short - term debt	**$ 425,452**	**100%**	$ 427,900	100%

On May 2, 2013, we issued $7.0 million of 6.43 percent unsecured senior notes pursuant to an agreement we entered into in 2010. These notes have similar covenants and default provisions as the Senior notes issued in June 2011 under the same agreement. Proceeds from these notes will be used to finance the redemption of the 9.57 percent and 10.03 percent series of FPU s first mortgage bonds, which is expected in May 2013.

Short-term Borrowings

Our outstanding short-term borrowings at March 31, 2013 and December 31, 2012 were $47.6 million and $61.2 million, respectively, at weighted average interest rates of 1.34 percent and 1.48 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 fund temporarily portions of the capital expenditure program. As of March 31, 2013, we had four unsecured bank lines of credit with two financial institutions for a total of $100.0 million. Two of these unsecured bank lines, totaling $60.0 million, are available under committed lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to $100.0 million of short-term debt, as required, from these unsecured bank lines of credit.

In addition to the four unsecured bank lines of credit, we entered into a new, unsecured short-term credit facility for $40.0 million with an existing lender on June 22, 2012. Short-term borrowings under this new facility bear interest at LIBOR plus 80 basis points or, at our discretion, the lender s base rate plus 80 basis points. This facility, which is structured in the form of a revolving credit note, matures on October 31, 2013.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the three months ended March 31, 2013 and 2012:

For the Three Months Ended March 31, *(in thousands)*	**2013**	**2012**
Net cash provided by (used in):		
Operating activities	**$ 34,968**	$ 34,550
Investing activities	**(18,640)**	(12,753)
Financing activities	**(17,081)**	(22,387)
Net decrease in cash and cash equivalents	**(753)**	(590)
Cash and cash equivalents beginning of period	**3,361**	2,637

Cash and cash equivalents end of period	**$ 2,608**	$ 2,047

Cash Flows Provided By Operating Activities

Changes in our cash flows from operating activities are attributable primarily to changes in net income, non-cash adjustments for depreciation and 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.

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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 and propane delivered by our natural gas 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.

During the three months ended March 31, 2013 and 2012, net cash flow provided by operating activities was $35.0 million and $34.6 million, respectively, a quarter-over-quarter increase of $418,000. Significant operating activities reflected in the change in cash flows provided by operating activities were as follows:

- Net cash flows related to income taxes increased by $4.3 million in the first three months of 2013, compared to the same period in 2012, due primarily to a tax refund of approximately $5.0 million received from the Internal Revenue Service during the first three months of 2013.

- Net cash flows from the changes in regulatory liabilities increased by approximately $4.9 million, due primarily to a increase in fuel costs due and collected from rate payers and a $1.2 million refund in January 2012 by Eastern Shore to customers as a result of its rate case settlement.

- Net cash flows from changes in accounts receivable and accounts payable decreased by approximately $8.8 million. The decrease was due primarily to collections and payments from our natural gas, electric, propane distribution operations. In addition, the timing of trading contracts entered into by our propane wholesale and marketing operation contributed to the changes in accounts receivable and accounts payable.

Cash Flows Used in Investing Activities

Net cash flows used in investing activities totaled $18.6 million and $12.8 million during the three months ended March 31, 2013 and 2012, respectively. Significant investing activities reflected in the change in cash flows used in investing activities were as follows:

- Cash utilized for capital expenditures was $16.2 million and $14.7 million for the first three months of 2013 and 2012, respectively.

- In February 2013, we acquired propane operating assets of Glades and paid approximately $2.4 million in cash.

- In February 2012, we sold an office building in West Palm Beach, Florida for approximately $2.2 million in cash.

Cash Flows Used by Financing Activities

Net cash flows used in financing activities totaled $17.1 million and $22.4 million for the three months ended March 31, 2013 and 2012, respectively. Significant financing activities reflected in the change in cash flows used in financing activities were as follows:

- During the first three months of 2013 we had a net repayment of $13.6 million under our line of credit agreements related to working capital, compared to $17.5 million during the same period in 2012, resulting in a period-over-period net cash increase of $3.9 million. Changes in cash overdrafts increased by $1.6 million, resulting in a period-over-period net cash increase.

- We paid $3.2 million and $3.0 million in cash dividends for the three months ended March 31, 2013 and 2012, respectively.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily our propane wholesale marketing subsidiary and natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. None of these subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at March 31, 2013 was $30.7 million, with the guarantees expiring on various dates through February 2014.

In addition to the corporate guarantees, we have issued a letter of credit for $1.0 million, which expires on September 12, 2013, 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 $400,000, which expires on December 2, 2013, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for $304,000 to our former primary insurance company, which will expire on June 1, 2013. There have been no draws on these letters of credit as of December 31, 2013. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for $2.3 million to TETLP related to the precedent agreement and firm transportation service agreement between our Delaware and Maryland divisions and TETLP, which is further described in Note 6, Other Commitments and Contingencies.

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Contractual Obligations

There has not been any material change in the contractual obligations presented in our 2012 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 the commodity and forward contract obligations at March 31, 2013.

	Payments Due by Period				
Purchase Obligations *(in thousands)*	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
Commodities [1]	$ 7,293	$ 100	$ 54	$	**$ 7,447**
Propane [2]	5,193				**5,193**
Total Purchase Obligations	**$ 12,486**	**$ 100**	**$ 54**	**$**	**$ 12,640**

(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 in the aggregate amount of $2.3 million. See Part I, Item 3, Quantitative and Qualitative Disclosures about Market Risk, below, for further information.

Environmental Matters

As more fully described in Note 5, Environmental Commitments and Contingencies, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we continue to work with federal and state environmental agencies to assess the environmental impact and explore corrective action at seven environmental sites. We believe that future costs associated with these sites will be recoverable in rates or through sharing arrangements with, or contributions by, other responsible parties.

Other Matters

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 their respective PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At March 31, 2013, we were involved in rate filings and/or regulatory matters in each of the jurisdictions in which we operate. Each of these rate filings and/or regulatory matters is fully described in Note 4, Rates and Other Regulatory Activities, to the unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Competition

Our natural gas and electric distribution operations and our natural gas transmission operations compete with other forms of energy, including natural gas, electricity, oil, propane and other alternative sources of energy. The principal competitive factors are price and, to a lesser extent, accessibility. Our natural gas distribution operations have several large-volume industrial customers that are able to use fuel oil as an alternative to natural gas. When oil prices decline, these interruptible customers may convert to oil to satisfy their fuel requirements, and our interruptible sales volumes may decline. Oil prices, as well as the prices of other fuels, fluctuate for a variety of reasons; therefore, future competitive conditions are not predictable. To address this uncertainty, we use flexible pricing arrangements on both the supply and sales sides of this business to compete with alternative fuel price fluctuations. As a result of the conversion of our natural gas transmission operations to open access and Chesapeake s Florida natural gas distribution division s restructuring of its services, these businesses have shifted from providing bundled transportation and sales service to providing only transmission and contract storage services. Our electric distribution operation currently does not face substantial competition because the electric utility industry in Florida has not been deregulated. In addition, natural gas is the only viable alternative fuel to electricity in our electric service territories and is available only in a small area.

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Our natural gas distribution operations in Delaware, Maryland and Florida offer unbundled transportation services to certain commercial and industrial customers. In 2002, Chesapeake s Florida natural gas distribution division, Central Florida Gas, extended such service to residential customers. With such transportation service available on our distribution systems, we are competing with third-party suppliers to sell gas to all customers. With respect to unbundled transportation services, our competitors include interstate transmission companies, if the distribution customers are located close enough to a transmission company s pipeline to make connections economically feasible. The customers at risk are usually large volume commercial and industrial customers with the financial resources and capability to bypass our existing distribution operations in this manner. In certain situations, our distribution operations may adjust services and rates for these customers to retain their business. We expect to continue to expand the availability of unbundled transportation service to additional classes of distribution customers in the future. We have also established a natural gas marketing operation in Florida, Delaware and Maryland to provide such service to customers eligible for unbundled transportation services.

Our propane distribution operations compete with several other propane distributors in their respective geographic markets, primarily on the basis of service and price, emphasizing responsive and reliable service. Our competitors generally include local outlets of national distributors and local independent distributors, whose proximity to customers entails lower costs to provide service. Propane competes with electricity as an energy source, because it is typically less expensive than electricity, based on equivalent BTU value. Propane also competes with home heating oil as an energy source. Since natural gas has historically been less expensive than propane, propane is generally not distributed in geographic areas served by natural gas pipeline or distribution systems.

The propane wholesale marketing operation competes against various regional and national marketers, many of which have significantly greater resources and are able to obtain price or volumetric advantages.

Our advanced information services subsidiary faces significant competition from a number of larger competitors having substantially greater resources available to them than does our subsidiary. In addition, changes in the advanced information services business are occurring rapidly and could adversely affect the markets for the products and services offered by these businesses. This segment competes on the basis of technological expertise, reputation and price.

Inflation

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. While the impact of inflation has remained low in recent years, natural gas and propane prices are subject to rapid fluctuations. In the regulated natural gas and electric distribution operations, fluctuations in natural gas and electricity prices are passed on to customers through the fuel cost recovery mechanism in our tariffs. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for our regulated operations and closely monitor the returns of our unregulated business operations. To compensate for fluctuations in propane gas prices, we adjust propane selling prices to the extent allowed by the market.

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, secured debt and convertible debentures. All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities, was $110.0 million at March 31, 2013, as compared to a fair value of $129.1 million, using a discounted cash flow methodology that incorporates a market interest rate that is 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.

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Our propane distribution business is exposed to market risk as a result of propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 5.6 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 forward contracts, primarily propane contracts, with various third parties. These contracts 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 IntercontinentalExchange. In certain cases, the futures contracts are settled by the payment or receipt of a net amount equal to the difference between the current market price of the futures contract and the original contract price; however, they may also be settled by physical receipt or delivery of propane.

The forward and futures contracts are entered into for trading and wholesale marketing purposes. The propane wholesale marketing business is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets and the credit risk of counter-parties, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts. Quantitative information on forward and futures contracts at March 31, 2013 is presented in the following tables.

At March 31, 2013	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	2,522,000	$.08275	$.09800	$ 0.9190
Purchase	2,522,000	$0.8250	$1.3176	$ 0.8941

Estimated market prices and weighted average contract prices are in dollars per gallon. All contracts expire by the end of the fourth quarter of 2013.

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.

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At March 31, 2013 and December 31, 2012, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)	**March 31, 2013**	December 31, 2012
Mark-to-market energy assets, including call options	**$ 150**	$ 210
Mark-to-market energy liabilities	**$ 85**	$ 331

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of the Company, with the participation of other Company officials, have evaluated our disclosure controls and procedures (as such term is defined under Rules 13a-15(e) and 15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of March 31, 2013. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2013.

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2013, 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, 2012, should be carefully considered, together with the other information contained or incorporated by reference in this Quarterly Report on Form 10-Q and in our other filings with the SEC in connection with evaluating the Company, our business and the forward-looking statements contained in this Report. Additional risks and uncertainties not known to us at present, or that we currently deem immaterial also may affect the Company. The occurrence of any of these known or unknown risks could have a material adverse impact on our business, financial condition, and results of operations.

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [(2)]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [(2)]
January 1, 2013 through January 31, 2013 [(1)]	261	$ 46.60		
February 1, 2013 through February 28, 2013		$		
March 1, 2013 through March 31, 2013		$		
Total	261	$ 46.60		

(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 15, Employee Benefit Plans in our latest Annual Report on Form 10-K for the year ended December 31, 2012. During the quarter, 261 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 4. Mine Safety Disclosures

None.

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Item 5. Other Information

None.

Item 6. Exhibits

31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated May 3, 2013.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated May 3, 2013.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 3, 2013.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 3, 2013.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

/s/ BETH W. COOPER
Beth W. Cooper

Senior Vice President and Chief Financial Officer
Date: May 3, 2013