CHESAPEAKE UTILITIES CORP
Form 10-Q
May 04, 2011

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United States
Securities and Exchange Commission
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended: March 31, 2011

OR

o **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 þ No o

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 o No o

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 o Accelerated filer þ Non-accelerated filer o Smaller reporting company o

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

Common Stock, par value $0.4867 9,550,814 shares outstanding as of April 30, 2011.

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GLOSSARY OF KEY TERMS

Frequently used abbreviations, acronyms, or terms used in this report:

Subsidiaries of Chesapeake Utilities Corporation

BravePoint	BravePoint®, Inc. is a wholly-owned subsidiary of Chesapeake Services Company, which is a wholly-owned subsidiary of Chesapeake
Chesapeake	The Registrant, the Registrant and its subsidiaries, or the Registrant s subsidiaries, as appropriate in the context of the disclosure
Company	The Registrant, the Registrant and its subsidiaries, or the Registrant s subsidiaries, as appropriate in the context of the disclosure
Eastern Shore	Eastern Shore Natural Gas Company, a wholly-owned subsidiary of Chesapeake
FPU	Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake, effective October 28, 2009
PESCO	Peninsula Energy Services Company, Inc., a wholly-owned subsidiary of Chesapeake
Peninsula Pipeline	Peninsula Pipeline Company, Inc., a wholly-owned subsidiary of Chesapeake
Sharp	Sharp Energy, Inc., a wholly-owned subsidiary of Chesapeake s and Sharp s subsidiary, Sharpgas, Inc.
Xeron	Xeron, Inc., a wholly-owned subsidiary of Chesapeake

Regulatory Agencies

Delaware PSC	Delaware Public Service Commission
EPA	United Sates Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FDEP	Florida Department of Environmental Protection
FDOT	Florida Department of Transportation
Florida PSC	Florida Public Service Commission
Maryland PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
PSC	Public Service Commission
SEC	Securities and Exchange Commission

Accounting Standards Related

GAAP	Generally Accepted Accounting Principles

Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CDD	Cooling Degree-Days
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per day
ECCR	Energy Conservation Cost Recovery

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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)*	2011	2010
Operating Revenues		
Regulated Energy	**$ 85,002**	$ 91,626
Unregulated Energy	**58,750**	59,269
Other	**2,845**	2,365
Total operating revenues	**146,597**	153,260
Operating Expenses		
Regulated energy cost of sales	**47,990**	54,263
Unregulated energy and other cost of sales	**44,289**	45,091
Operations	**19,837**	18,714
Maintenance	**1,702**	1,700
Depreciation and amortization	**5,021**	5,128
Other taxes	**2,919**	2,966
Total operating expenses	**121,758**	127,862
Operating Income	**24,839**	25,398
Other income, net of expenses	**22**	115
Interest charges	**2,150**	2,363
Income Before Income Taxes	**22,711**	23,150
Income tax expense	**8,964**	9,176
Net Income	**$ 13,747**	$ 13,974
Weighted-Average Common Shares Outstanding:		
Basic	**9,535,381**	9,419,932
Diluted	**9,633,796**	9,524,298
Earnings Per Share of Common Stock:		
Basic	**$ 1.44**	$ 1.48
Diluted	**$ 1.43**	$ 1.47
Cash Dividends Declared Per Share of Common Stock	**$ 0.330**	$ 0.315

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,	**2011**	**2010**
(in thousands)		
Operating Activities		
Net Income	**$ 13,747**	$ 13,974
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**5,021**	5,128
Depreciation and accretion included in other costs	**1,055**	861
Deferred income taxes, net	**8,889**	369
Loss on sale of assets	**57**	
Unrealized gain on commodity contracts	**(83)**	(215)
Unrealized gain on investments	**(143)**	(51)
Employee benefits	**497**	(272)
Share-based compensation	**329**	333
Other, net	**(16)**	41
Changes in assets and liabilities:		
Purchase of investments	**(44)**	(30)
Accounts receivable and accrued revenue	**7,466**	15,800
Propane inventory, storage gas and other inventory	**5,777**	6,155
Regulatory assets	**488**	2,164
Prepaid expenses and other current assets	**1,528**	1,913
Accounts payable and other accrued liabilities	**(10,670)**	(12,741)
Income taxes receivable	**(270)**	8,580
Accrued interest	**844**	949
Customer deposits and refunds	**(2,165)**	604
Accrued compensation	**(2,009)**	(980)
Regulatory liabilities	**4,372**	3,314
Other liabilities	**(400)**	503
Net cash provided by operating activities	**34,270**	46,399
Investing Activities		
Property, plant and equipment expenditures	**(8,355)**	(6,099)
Proceeds from sales of assets	**299**	
Purchase of investments		(310)
Environmental expenditures	**(164)**	(367)
Net cash used in investing activities	**(8,220)**	(6,776)
Financing Activities		
Common stock dividends	**(2,836)**	(2,683)
(Purchase) issuance of stock for Dividend Reinvestment Plan	**(307)**	152
Change in cash overdrafts due to outstanding checks	**(2,791)**	(834)
Net repayment under line of credit agreements	**(19,740)**	(29,188)
Other Short-term borrowing		29,100

Repayment of long-term debt		**(35)**		(28,858)
Net cash used in financing activities		**(25,709)**		(32,311)
Net Decrease in Cash and Cash Equivalents		**341**		7,312
Cash and Cash Equivalents Beginning of Period		**1,643**		2,828
Cash and Cash Equivalents End of Period	**$**	**1,984**	$	10,140

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

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

Assets	**March 31, 2011**	**December 31, 2010**
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated energy	**$ 505,448**	$ 500,689
Unregulated energy	**61,595**	61,313
Other	**18,326**	16,989
Total property, plant and equipment	**585,369**	578,991
Less: Accumulated depreciation and amortization	**(125,437)**	(121,628)
Plus: Construction work in progress	**4,941**	5,394
Net property, plant and equipment	**464,873**	462,757
Investments, at fair value	**3,835**	4,036
Current Assets		
Cash and cash equivalents	**1,984**	1,643
Accounts receivable (less allowance for uncollectible accounts of $1,122 and $1,194, respectively)	**85,699**	88,074
Accrued revenue	**9,888**	14,978
Propane inventory, at average cost	**6,553**	8,876
Other inventory, at average cost	**3,103**	3,084
Regulatory assets	**227**	51
Storage gas prepayments	**1,610**	5,084
Income taxes receivable	**7,018**	6,748
Deferred income taxes	**2,138**	2,191
Prepaid expenses	**3,077**	4,613
Mark-to-market energy assets	**339**	1,642
Other current assets	**182**	245
Total current assets	**121,818**	137,229
Deferred Charges and Other Assets		
Goodwill	**35,613**	35,613
Other intangible assets, net	**3,376**	3,459
Long-term receivables	**77**	155
Regulatory assets	**22,857**	23,884
Other deferred charges	**3,853**	3,860
Total deferred charges and other assets	**65,776**	66,971

Total Assets	**$ 656,302**	$ 670,993

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

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

Capitalization and Liabilities	**March 31, 2011**	**December 31, 2010**
(in thousands, except shares and per share data)		
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	**$ 4,648**	$ 4,635
Additional paid-in capital	**148,055**	148,159
Retained earnings	**87,355**	76,805
Accumulated other comprehensive loss	**(3,043)**	(3,360)
Deferred compensation obligation	**786**	777
Treasury stock	**(786)**	(777)
Total stockholders equity	**237,015**	226,239
Long-term debt, net of current maturities	**89,565**	89,642
Total capitalization	**326,580**	315,881
Current Liabilities		
Current portion of long-term debt	**9,196**	9,216
Short-term borrowing	**41,427**	63,958
Accounts payable	**53,307**	65,541
Customer deposits and refunds	**24,221**	26,317
Accrued interest	**2,633**	1,789
Dividends payable	**3,151**	3,143
Accrued compensation	**4,821**	6,784
Regulatory liabilities	**13,440**	9,009
Mark-to-market energy liabilities	**107**	1,492
Other accrued liabilities	**12,527**	10,393
Total current liabilities	**164,830**	197,642
Deferred Credits and Other Liabilities		
Deferred income taxes	**89,079**	80,031
Deferred investment tax credits	**223**	243
Regulatory liabilities	**3,675**	3,734
Environmental liabilities	**9,205**	10,587
Other pension and benefit costs	**18,077**	18,199
Accrued asset removal cost Regulatory liability	**35,593**	35,092
Other liabilities	**9,040**	9,584
Total deferred credits and other liabilities	**164,892**	157,470

Total Capitalization and Liabilities	**$ 656,302**	$ 670,993

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

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

	Common Stock		Additional		Accumulated Other			
(in thousands, except shares and per share data)	Number of Shares[6]	Par Value	Paid-In Capital	Retained Earnings	Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2009	**9,394,314**	**$ 4,572**	**$ 144,502**	**$ 63,231**	**$ (2,524)**	**$ 739**	**$ (739)**	**$ 209,781**
Net Income				26,056				26,056
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					8			8
Net Loss [5]					(844)			(844)
Total comprehensive income								25,220
Dividend Reinvestment Plan	53,806	26	1,699					1,725
Retirement Savings Plan	27,795	14	889					903
Conversion of debentures	11,865	6	196					202
Tax benefit on share based compensation			253					253
Share based compensation [1] [3]	36,415	17	620					637
Deferred Compensation Plan						38	(38)	
Purchase of treasury stock	1,144						(38)	(38)
Sale and distribution of treasury stock	(1,144)						38	38
Dividends on stock-based compensation				(104)				(104)
Cash dividends [2]				(12,378)				(12,378)
Balances at December 31, 2010	**9,524,195**	**4,635**	**148,159**	**76,805**	**(3,360)**	**777**	**(777)**	**226,239**
Net Income				13,747				13,747
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					2			2
Net Gain [5]					315			315
Total comprehensive income								14,064
Dividend Reinvestment Plan			(5)					(5)
Retirement Savings Plan	2,002	1	78					79
Conversion of debentures	3,637	2	60					62
Share based compensation [1] [3]	19,630	10	(237)					(227)
Deferred Compensation Plan						9	(9)	
Purchase of treasury stock	(242)						(9)	(9)
Sale and distribution of treasury stock	242						9	9
Dividends on stock-based compensation				(46)				(46)
Cash dividends [2]				(3,151)				(3,151)
Balances at March 31, 2011	**9,549,464**	**$ 4,648**	**$ 148,055**	**$ 87,355**	**$ (3,043)**	**$ 786**	**$ (786)**	**$ 237,015**

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

(2) Cash dividends declared per share for the periods ended March 31, 2011 and December 31, 2010 were $0.33 and $1.305, respectively.

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For the periods ended March 31, 2011 and December 31, 2010 the Company withheld 12,324 and 17,695 shares, respectively, for taxes.

(4) Tax expense recognized on the prior service cost component of employees benefit plans for the periods ended March 31, 2011 and December 31, 2010 were approximately $1 and $5, respectively.

(5) Tax expense (benefit) recognized on the net gain (loss) component of employees benefit plans for the periods ended March 31, 2011 and December 31, 2010, were $211 and ($541), respectively.

(6) Includes 29,838 and 29,596 shares at March 31, 2011 and December 31, 2010, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

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 the Registra and its subsidiaries, or the Registrant s 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 United States of America Generally Accepted Accounting Principles (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 filed with the SEC on March 8, 2011. 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 statements of income and cash flows for the three months ended March 31, 2010 to conform to the current year s presentation. These reclassifications are considered immaterial to the overall presentation of our consolidated financial statements.

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2. Calculation of Earnings Per Share

For the Three Months Ended March 31,	2011	2010
(in thousands, except shares and per share data)		
Calculation of Basic Earnings Per Share:		
Net Income	**$ 13,747**	$ 13,974
Weighted average shares outstanding	**9,535,381**	9,419,932
Basic Earnings Per Share	**$ 1.44**	$ 1.48
Calculation of Diluted Earnings Per Share:		
Reconciliation of Numerator:		
Net Income	**$ 13,747**	$ 13,974
Effect of 8.25% Convertible debentures	**16**	19
Adjusted numerator Diluted	**$ 13,763**	$ 13,993
Reconciliation of Denominator:		
Weighted shares outstanding Basic	**9,535,381**	9,419,932
Effect of dilutive securities:		
Share-based Compensation	**23,246**	16,090
8.25% Convertible debentures	**75,169**	88,276
Adjusted denominator Diluted	**9,633,796**	9,524,298
Diluted Earnings Per Share	**$ 1.43**	$ 1.47

3. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective Public Service Commission (PSC); Eastern Shore Natural Gas Company (Eastern Shore), our natural gas transmission operation, is subject to regulation by the Federal Energy Regulatory Commission (FERC); and Peninsula Pipeline Company, Inc. (Peninsula Pipeline) is subject to regulation by the Florida Public Service Commission (Florida PSC). Chesapeake s Florida natural gas distribution division and FPU s natural gas and electric operations continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

On September 2, 2008, our Delaware division filed with the Delaware Public Service Commission (Delaware PSC) its annual Gas Sales Service Rates (GSR) Application, seeking approval to change its GSR, effective November 1, 2008. On July 7, 2009, the Delaware PSC granted approval of a settlement agreement presented by the parties in this docket, which included the Delaware PSC, our Delaware division and the Division of the Public Advocate. As part of the settlement, the parties agreed to develop a record in a later proceeding on the price charged by the Delaware division for the temporary release of transmission pipeline capacity to our natural gas marketing subsidiary, Peninsula Energy Services Company, Inc. (PESCO). On January 8, 2010, the Hearing Examiner in this proceeding issued a report of Findings and Recommendations in which he recommended, among other things, that the Delaware PSC require the Delaware division to refund to its firm service customers the difference between what the Delaware division would have received had the capacity released to PESCO been priced at the maximum tariff rates under asymmetrical pricing principles and the amount actually received by the Delaware division for capacity released to PESCO. The Hearing Examiner also recommended that the

Delaware PSC require us to adhere to asymmetrical pricing principles in all future capacity releases by the Delaware division to PESCO, if any. If the Hearing Examiner s refund recommendation for past capacity releases were ultimately approved without modification by the Delaware PSC, the Delaware division would have to credit to its firm service customers amounts equal to the maximum tariff rates that the Delaware division pays for long-term capacity, which we estimated to be approximately $700,000, even though the temporary releases were made at lower rates based on competitive bidding procedures required by the FERC s capacity release rules. On February 18, 2010, we filed exceptions to the Hearing Examiner s recommendations.

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At the hearing on March 30, 2010, the Delaware PSC agreed with us that the Delaware division had been releasing capacity based on a previous settlement approved by the Delaware PSC and, therefore, did not require the Delaware division to issue any refunds for past capacity releases. The Delaware PSC, however, required the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO until a more appropriate pricing methodology is developed and approved. The Delaware PSC issued an order on May 18, 2010 elaborating its decisions at the March hearing and directing the parties to reconvene in a separate docket to determine if a pricing methodology other than asymmetrical pricing principles should apply to future capacity releases by the Delaware division to PESCO.

On June 17, 2010, the Division of the Public Advocate filed an appeal with the Delaware Superior Court, asking it to overturn the Delaware PSC s decision with regard to refunds for past capacity releases. On June 28, 2010, the Delaware division filed a Notice of Cross Appeal with the Delaware Superior Court asking it to overturn the Delaware PSC s decision with regard to requiring the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO. The parties involved filed opening briefs with the Delaware Superior Court on September 30, 2010, answering briefs on October 20, 2010, and reply briefs on November 3, 2010. Oral arguments were presented on March 14, 2011, in which the parties presented their respective positions. We have not accrued any contingent liability related to potential refunds for past capacity releases. We anticipate that the Court will render a decision sometime in 2011. In addition, due to the ongoing legal proceeding, the parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases. Since the Delaware PSC s Order on May 18, 2010, the Delaware division has not released any capacity to PESCO.

On September 1, 2010, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2010. On September 21, 2010, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2010, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The Delaware division anticipates a final decision no later than the third quarter of 2011.

On March 10, 2011, the Delaware division filed with the Delaware PSC an application requesting approval to guarantee certain debt of Florida Public Utilities Company (FPU). Specifically, the Delaware division sought approval to execute a Seventeenth Supplemental Indenture, in which Chesapeake guarantees the payment of certain debt of FPU and FPU is permitted to deliver Chesapeake s consolidated financial statements in lieu of FPU s stand-alone financial statements to satisfy certain covenants within the indenture of FPU s debt. The Delaware PSC granted approval of this guarantee at its regularly scheduled meeting on April 4, 2011.

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Maryland

On December 14, 2010, the Maryland Public Service Commission (Maryland PSC) held an evidentiary hearing to determine the reasonableness of the four quarterly gas cost recovery filings submitted by the Maryland division during the 12 months ended September 30, 2010. No issues were raised at the hearing, and on December 20, 2010, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. This proposed Order became a final Order of the Maryland PSC on January 20, 2011.

On March 2, 2011, the Maryland division filed with the Maryland PSC an application for a franchise executed between the Maryland division and the Board of County Commissioners of Cecil County, Maryland. In this franchise agreement, the County granted the Maryland division a 50-year, non-exclusive, franchise to construct and operate natural gas distribution facilities within the present and future jurisdictional boundaries of Cecil County. On April 11, 2011, the Maryland PSC issued an Order approving the franchise between the Maryland division and Cecil County, subject to no adverse comments being received within 30 days after the issuance of the Order. No adverse comments have been filed since the Order.

Florida

In the Order dated December 15, 2009, approving the rate increase for Chesapeake s Florida division, the Florida PSC ordered Chesapeake s Florida division and FPU s natural gas distribution operation to submit data that details all known benefits, synergies, cost savings and cost increases resulting from the merger in a Come-Back filing. We submitted this filing on April 29, 2010 and also requested the recovery, through rates, of approximately $34.2 million in acquisition adjustment (the price paid in excess of the book value) and $2.2 million in merger-related costs. We did not request any change to the existing rates previously approved by the Florida PSC. In 2010, we recorded a $750,000 accrual based on our assessment of FPU s current earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in the Come-Back filing.

On September 1, 2010, FPU s electric distribution operation filed its annual Fuel and Purchased Power Cost Recovery Clause, seeking final approval of the levelized fuel adjustment and purchased power cost recovery factors for 2011. On December 20, 2010, the Florida PSC issued an order approving the proposed 2011 fuel rates, effective for meters read on and after January 1, 2011.

On September 10, 2010, FPU s electric distribution operation filed its annual Energy Conservation Cost Recovery (ECCR) Clause, seeking final approval of the 2009 conservation-related revenues and expenses and new ECCR recovery factors for 2011. On November 29, 2010, the Florida PSC issued an order approving the proposed 2011 ECCR recovery factors, effective for meters read on and after January 1, 2011.

On September 13, 2010, Chesapeake s Florida division, FPU s Indiantown division and FPU s natural gas distribution operation separately filed their annual ECCR Clauses, seeking final approval of the 2009 conservation-related revenues and expenses and new ECCR recovery factors for 2011. On November 29, 2010, the Florida PSC issued an order approving all of the proposed 2011 ECCR recovery factors, effective for meters read on or after January 1, 2011.

On September 13, 2010, FPU s natural gas distribution operation filed its annual Purchased Gas Adjustment (PGA) Clause, seeking final approval of its 2009 purchased gas-related revenues and expenses and new PGA cap rate for 2011. On November 29, 2010, the Florida PSC issued an order approving the proposed 2011 PGA cap rate, effective for meters read on or after January 1, 2011.

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On, July 7, 2009, the City Commission of Marianna, Florida (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 that shall be mutually agreed upon by FPU and the City. 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 the corporate limits of the City of Marianna. If the rates are not in effect by February 17, 2011, the City has the right to give notice to FPU within 180 days thereafter of its intent to exercise its option 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 an electric distribution facility. If the purchase is approved by the Marianna Commission and by the referendum, the closing of the purchase must occur within 12 months after the referendum is approved. If the City elects to purchase the Marianna property, the Franchise Agreement requires the City to pay FPU the fair market value for such property as determined by three qualified appraisers. Future financial results would be negatively impacted from the loss in earnings generated by FPU from its approximately 3,000 customers in the City under the franchise agreement.

In accordance with the terms of the Franchise Agreement, FPU developed reasonable TOU and interruptible rates and on December 14, 2010, filed a petition with the Florida PSC for authority to implement such proposed TOU and interruptible rates for approval and implementation on or before February 17, 2011. On February 11, 2011, the Florida PSC issued an order approving the proposed TOU and interruptible rates for a four-year period. The City has objected to the proposed rates and has filed a petition protesting the entry of the Florida PSC s order.

As disclosed in Note 5, Other Commitments and Contingencies, the City, on March 2, 2011, filed a declaratory action 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 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. FPU filed its answer with the court in the declaratory action on March 28, 2011.

On January 26, 2011, FPU filed a Petition with the Florida PSC for approval of an amendment to the Generation Services Agreement with Gulf Power Corporation. The amendment provides for a reduction in the capacity demand quantity, which provides for the savings necessary to support the TOU and interruptible rates approved in Docket No. 100459-EI. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019. The Florida PSC Staff is expected to issue their recommendation on May 12, 2011. This Petition is scheduled for the May 24, 2011 Florida PSC Agenda Conference.

Eastern Shore

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

Energylink Expansion Project: In 2006, Eastern Shore proposed to develop, construct and operate approximately 75 miles of new pipeline facilities from the existing Cove Point Liquefied Natural Gas terminal in Calvert County, Maryland, crossing under the Chesapeake Bay into Dorchester and Caroline Counties, Maryland, to points on the Delmarva Peninsula, where such facilities would interconnect with Eastern Shore s existing facilities in Sussex County, Delaware. In April 2009, Eastern Shore terminated this project based on increased construction costs over its original projection, and initiated billing to recover approximately $3.2 million of costs incurred in connection with this project and the related cost of capital over a period of 20 years in accordance with the terms of the precedent agreements executed with the two participating customers and approved by the FERC. One of the two participating customers is Chesapeake, through its Delaware and Maryland divisions. During 2010, Eastern Shore and the participating customers negotiated to reduce the recovery period of this cost from 20 years to five years. On January 27, 2011, Eastern Shore filed with the FERC the request to amend the cost recovery period, which was approved by the FERC on February 14, 2011. Eastern Shore began billing the five-year surcharge effective March 1, 2011.

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Mainline Extension and Interconnect Project: On March 5, 2010, Eastern Shore submitted an Application for Certificate of Public Convenience and Necessity to the FERC related to a proposed mainline extension and interconnect project that would tie into the interstate pipeline system of TETLP. Eastern Shore s project involved building and operating an eight-mile mainline extension from Eastern Shore s existing facility in Parkesburg, Pennsylvania to the interconnection with TETLP at Honey Brook, Pennsylvania. The estimated capital cost of this project was approximately $19.4 million. On September 3, 2010, the FERC approved Eastern Shore s application, subject to certain environmental conditions, some of which had to be met prior to the commencement of construction. Eastern Shore accepted the Order Issuing Certificate on October 4, 2010. On October 13, 2010, the FERC issued a Notice to Proceed with the construction of the project s facilities as all conditions that must be met prior to the commencement of construction were satisfied. The facilities were completed on December 15, 2010, and on December 21, Eastern Shore received FERC approval to place the facilities into service. Eastern Shore commenced billing for the new service on January 1, 2011.

Rate Case Filing: On December 30, 2010, Eastern Shore filed a base rate proceeding in compliance with the terms of the settlement in its prior base rate proceeding. Eastern Shore s filed rates, proposed to be effective February 1, 2011, reflect an annual increase of $6,748,628 over its current rates. The proposed rate increase reflects increases in operating and maintenance expenses, depreciation expense, and return on existing and new gas plant facilities that are expected to be placed into service before June 30, 2011. Eastern Shore proposed a return on equity of 13.5 percent. The FERC issued a notice of the filing on January 3, 2011. Protests were received from several interested parties and other parties intervened in the proceeding. On January 31, 2011, the FERC issued its Order accepting the filing and suspending its effectiveness for the full five-month period permitted under the Natural Gas Act. The discovery process commenced on February 22, 2011 and FERC Staff performed an on-site audit on March 16-17, 2011. Staff issued their Top Sheet on April 7, 2011, summarizing Staff s initial position on this case, and the first settlement conference was held on April 14, 2011. Eastern Shore expects the base rate proceeding to be completed in 2011.

Mainline Extension Project: On April 1, 2011, Eastern Shore filed a notice of its intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 3,405 dekatherms per day (Dts/d) of natural gas to the Delaware City Refining Company LLC. The FERC published notice of this filing on April 7, 2011; assuming no protest during the 60-day period following the notice, the requested authorization will become effective.

On April 28, 2011, Eastern Shore filed a notice of its intent under its blanket certification to construct, own and operate new mainline facilities to deliver additional firm service of 6,250 Dts/d of natural gas to Chesapeake s Delaware and Maryland divisions and Eastern Shore Gas, an unaffiliated provider of piped propane service in Maryland. The FERC will publish notice of this filing within ten days of the date of the filing; assuming no protest during the 60-day period following the notice, the requested authorization will become effective.

Also on April 28, 2011, Eastern Shore file a notice of its intent under its blanket certification to construct, own and operate new mainline facilities to deliver additional firm service of 4,070 Dts/d of natural gas to Chesapeake s Maryland division. The FERC will publish notice of this filing within ten days of the date of the filing; assuming no protest during the 60-day period following the notice, the requested authorization will become effective.

Eastern Shore also had developments in the following FERC matters:

On March 7, 2011, Eastern Shore filed certain tariff sheets to amend the creditworthiness provisions contained in its FERC Gas Tariff. The FERC issued notice of the filing on that same day. On April 6, 2011, the FERC issued an Order accepting and suspending Eastern Shore s filed tariff revisions for an effective date of April 1, 2011, subject to Eastern Shore submitting certain clarifications with regard to certain proposed revisions.

On April 18, 2011, Eastern Shore submitted its annual Interruptible Revenue Sharing Report to the FERC. Eastern Shore reported in this filing that its interruptible revenue did not exceed its annual threshold amount, which would trigger sharing of excess interruptible revenues with its firm service customers. Consequently, Eastern Shore is not required to refund to its firm customers any portion of its interruptible revenue received for the period April 2010 through March 2011.

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4. Environmental Commitments and Contingencies

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites.

We have participated in the investigation, assessment or remediation, and have certain 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 the Environment (MDE) regarding a seventh former MGP site located in Cambridge, Maryland. The Key West, Pensacola, Sanford and West Palm Beach sites are related to FPU, for which we assumed in the merger any existing and future contingencies.

As of March 31, 2011, we had $324,000 in environmental liabilities related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of the future costs associated with those sites. As of March 31, 2011, we had approximately $1.2 million in regulatory and other assets for future recovery of environmental costs from Chesapeake s customers through our approved rates. As of March 31, 2011, we had approximately $11.4 million in environmental liabilities related to FPU s MGP sites in Florida, primarily from the West Palm Beach site, which represents our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs from insurance and from customers through rates. Approximately $7.9 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of March 31, 2011. We also had approximately $6.1 million in regulatory assets for future recovery of environmental costs from FPU s customers.

The following discussion provides details on each site.

Salisbury, Maryland

We have substantially completed remediation of this site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water contamination. During 1996, we completed construction of an Air Sparging and Soil-Vapor Extraction (AS/SVE) system and began remediation procedures. We have reported the remediation and monitoring results to the MDE on an ongoing basis since 1996. In February 2002, the MDE granted permission to permanently decommission the AS/SVE system 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.

Through March 31, 2011, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies. We have recovered approximately $2.3 million through insurance proceeds or in rates, and $638,000 is expected to be recovered through future rates.

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 the Florida Department of Environmental Protection (FDEP), we are obligated to assess and remediate environmental impacts at this former MGP site. In 2001, the FDEP approved a Remedial Action Plan (RAP) requiring construction and operation of a Bio-Sparging and Soil/Vapor Extraction (BS/SVE) treatment system to address soil and groundwater impacts at a portion of the site. The BS/SVE treatment system has been in operation since October 2002. Modifications and upgrades to the BS/SVE treatment system were completed in October 2009. The Sixteenth Semi-Annual RAP Implementation Status Report was submitted to the FDEP in December 2010. The groundwater sampling results through December 2010 show a continuing reduction in contaminant concentrations and indicate that the recent treatment system modifications and upgrades have had a beneficial impact on the rate of reduction. At present, we predict that remedial action objectives could be met in approximately two to three years for the area being treated by the BS/SVE treatment system. The total expected cost of operating and monitoring the system is approximately $46,000.

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The BS/SVE treatment system at the Winter Haven site does not address impacted soils in the southwest corner of the site. On April 16, 2010, a soil excavation interim RAP describing the proposed excavation of approximately 4,000 cubic yards of impacted soils from the southwest corner of the site was submitted to the FDEP for review. On June 24, 2010, the FDEP provided comments on the soil excavation interim RAP by letter, to which we responded, and a subsequent conditional approval letter was issued by FDEP on August 27, 2010. The cost to implement this excavation plan has been estimated at $250,000; however, this estimate does not include costs associated with dewatering or shoreline stabilization, which would be required to complete the excavation. Because the costs associated with shoreline stabilization and dewatering (including treatment and discharge of the pumped water) are likely to be substantial, alternatives to this excavation plan are being evaluated. As a result, we plan to perform the excavation in late 2011 or early 2012.

The 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 the 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.

Through March 31, 2011, we have incurred and paid approximately $1.7 million for remedial activities at this site, and we have estimated and accrued for additional future costs of $324,000. We have recovered through rates $1.4 million of the costs to remediate the Winter Haven site and continue to expect that the remaining $602,000, which is included in regulatory assets, will be recoverable from customers through our approved rates.

Key West, Florida

FPU formerly owned and operated an 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 September 2010, FDEP issued a Preliminary Contamination Assessment Report, for additional soil and groundwater investigation work that was undertaken by FDEP in November 2009 and January 2010, after 17 years of regulatory inactivity. Because FDEP observed that some soil and groundwater standards were exceeded, FDEP is seeking to meet with FPU and the current site owner to discuss additional field work which the FDEP believes is warranted for the site. Potential costs for investigation and remediation are projected to be $153,000.

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida. The MGP 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 (NFA) determination for the site, which must include a requirement for institutional and engineering controls. On November 9, 2010, an NFA Proposal was submitted to FDEP, along with a draft restrictive covenant for that portion of the property currently owned by FDOT. At this point, it is anticipated that no further monitoring will be required on the site. FPU s total remaining consulting and remediation costs for this site are projected to be $7,000.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, a former MGP site which was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP. In late September 2006, the United States Environmental Protection Agency (EPA) sent a Special Notice Letter, notifying FPU, and the other responsible parties at the site (Florida Power Corporation, Florida Power & Light Company, Atlanta Gas Light Company, and the city of Sanford, Florida, collectively with FPU, the Sanford Group), of EPA s selection of a final remedy for OU1 (soils), OU2 (groundwater), and OU3 (sediments) for the site. The total estimated remediation costs for this site were projected at the time by EPA to be approximately $12.9 million.

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In January 2007, FPU and other members of the Sanford Group signed a Third Participation Agreement, which provides for funding the final remedy approved by 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 million, or $650,000. As of March 31, 2011, FPU has paid $650,000 to the Sanford Group escrow account for its share of funding requirements.

The Sanford Group, EPA and the U.S. Department of Justice agreed to a Consent Decree in March 2008, which was entered by the federal court in Orlando, Florida on January 15, 2009. The Consent Decree obligates the Sanford Group to implement the remedy approved by EPA for the site. The total cost of the final remedy is now estimated at approximately $18 million. 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.

Several members of the Sanford Group have concluded negotiations with two adjacent property owners to resolve damages that the property owners allege they have 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.

As of March 31, 2011, FPU s remaining share of remediation expenses, including attorneys fees and costs, is estimated to be $20,000. 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 million 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.

West Palm Beach, Florida

We are currently evaluating remedial options to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated an MGP. Pursuant to a Consent Order between FPU and the FDEP, effective April 8, 1991, FPU completed the delineation of soil and groundwater impacts at the site. On June 30, 2008, FPU transmitted to the FDEP a revised feasibility study, evaluating appropriate remedies for the site. This revised feasibility study evaluated a wide range of remedial alternatives based on criteria provided by applicable laws and regulations. On April 30, 2009, the FDEP issued a remedial action order, which it subsequently withdrew. In response to the Order and as a condition to its withdrawal, FPU committed to perform additional field work in 2009 and complete an additional engineering evaluation of certain remedial alternatives. The scope of this work has increased in response to FDEP s requests for additional information.

FPU performed additional field work in August 2010, which included the installation of additional groundwater monitoring wells and performance of a comprehensive groundwater sampling event. FPU also performed vapor intrusion sampling in October 2010. The results of the field work were submitted to the FDEP for their review and comment in October 2010. On November 4, 2010, the FDEP issued its comments on the feasibility study and the proposed remedy. On November 16, 2010, FPU presented to the FDEP a new remedial action plan for the site, and the FDEP agreed with FPU s proposal to implement a phased approach to remediation. On December 22, 2010, FPU submitted to the FDEP an interim RAP to remediate the east parcel of the site, which the FDEP conditionally approved on February 4, 2011.

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FPU is currently implementing the interim RAP for the east parcel of the West Palm Beach site, including the incorporation of FDEP s conditions for approval. We estimate that the updated costs of remediation will range from approximately $5.1 million to $13.3 million. This estimate does not include any costs associated with relocation of FPU s operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future re-development of the properties.

We continue to expect that all costs related to these activities will be recoverable from customers through rates.

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.

5. Other Commitments and Contingencies

Litigation

In May 2010, a FPU propane customer filed a class action complaint against FPU in Palm Beach County, Florida, alleging, among other things, that FPU acted in a deceptive and unfair manner related to a particular charge by FPU on its bills to propane customers and the description of such charge. The suit sought to certify a class comprised of FPU propane customers to whom such charge was assessed since May 2006 and requested damages and statutory remedies based on the amounts paid by FPU customers for such charge. FPU vigorously denies any wrongdoing and maintains that the particular charge at issue is customary, proper and fair. Without any admission by FPU of any wrongdoing, validity of the claims or a properly certifiable class for the complaint, FPU entered into a settlement agreement with the plaintiff in September 2010 to avoid the burden and expenses of continued litigation. The court approved the final settlement, and the judgment became final on March 13, 2011. In 2010, we recorded $1.2 million of the total estimated costs related to this litigation. Pursuant to the final settlement, the distribution to the class must be made by May 13, 2011.

On March 2, 2011, the City of Marianna, Florida filed a declaratory action against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging that FPU breached its obligations under its franchise with the City to provide electric service to customers within and without the City by failing: (i) to develop and implement TOU and interruptible rates that were mutually agreed to by the City and FPU; (ii) to have such mutually agreed upon rates in effect by February 17, 2011; and (iii) to have such rates available to all of FPU s customers located within and without the corporate limits of the City. The City is seeking a declaratory judgment 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 for approval of the purchase and the operation by the City of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum, the closing of the purchase must occur within 12 months after the referendum is approved. On March 17, 2011, FPU filed a Motion to Dismiss the City s protest and request for hearing. On March 24, 2011, the City filed its response to FPU s Motion to Dismiss. On March 28, 2011, FPU filed its answer with the court in the declaratory action. FPU intends to vigorously contest this litigation and intends to oppose the adoption of any proposed referendum to approve the purchase of the FPU property in the City of Marianna.

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. We have a contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. This contract expires on March 31, 2012.

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Chesapeake s Florida natural gas distribution division has firm transportation service contracts with Florida Gas Transmission Company (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 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.

PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements before its existing agreements expire in May 2011.

FPU s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU s agreement with JEA requires FPU to comply with the following ratios based on the result 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. 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 operation 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 action taken or proposed to be taken to be 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, 2011, FPU was in compliance with all of the requirements of its fuel supply contracts.

Corporate Guarantees

The Board of Directors has previously authorized the Company to issue up to $35 million of corporate guarantees or letters of credit on behalf of our subsidiaries. On March 2, 2011, the board increased this limit from $35 million to $45 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 in our financial statements when incurred. The aggregate amount guaranteed at March 31, 2011 was $26.0 million, with the guarantees expiring on various dates through 2011.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $441,000, which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various outstanding insurance policies. As a result of the recent change in our primary insurance company, we have issued an additional letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2011. There have been no draws on these letters of credit as of March 31, 2011. 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 $2.1 million to TETLP related to the Precedent Agreement with TETLP, which is further described below.

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Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in conjunction with its new expansion project, which is expected to expand TETLP s mainline system by up to 190,000 Dts/d. The Precedent Agreement provides that, upon satisfaction of certain conditions, the parties will execute two firm transportation service contracts, one for our Delaware division and one for our Maryland division, for 30,000 and 10,000 Dts/d, respectively, to be effective on the service commencement date of the project, which is currently projected to occur in November 2012. Each firm transportation service contract shall, among other things, provide for: (a) the maximum daily quantity of Dts/d described above; (b) a term of 15 years; (c) a receipt point at Clarington, Ohio; (d) a delivery point at Honey Brook, Pennsylvania; and (e) certain credit standards and requirements for security. Commencement of service and TETLP s and our rights and obligations under the two firm transportation service contracts are subject to satisfaction of various conditions specified in the Precedent Agreement.

Our Delmarva natural gas supplies are currently received primarily from the Gulf of Mexico natural gas production region and are transported through three interstate upstream pipelines, two of which interconnect directly with Eastern Shore s transmission system. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide us with an additional direct interconnection with Eastern Shore s transmission system and access to new sources of natural gas supplies from other natural gas production regions, including the Appalachian production region, thereby providing increased reliability and diversity of supply. They will also provide our Delaware and Maryland divisions with additional upstream transportation capacity to meet current customer demands and to plan for sustainable growth.

The Precedent Agreement provides that the parties shall promptly meet and work in good faith to negotiate a mutually acceptable reservation rate. Failure to agree upon a mutually acceptable reservation rate would have enabled either party to terminate the Precedent Agreement, and would have subjected us to reimburse TETLP for certain pre-construction costs; however, on July 2, 2010, our Delaware and Maryland divisions executed the required reservation rate agreements with TETLP.

The Precedent Agreement requires us to reimburse TETLP for our proportionate share of TETLP s pre-service costs incurred to date, if we terminate the Precedent Agreement, are unwilling or unable to perform our material duties and obligations thereunder, or take certain other actions whereby TETLP is unable to obtain the authorizations and exemptions required for this project. If such termination were to occur, we estimate that our proportionate share of TETLP s pre-service costs could be approximately $9.6 million as of March 31, 2011. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, which is expected to be in the fourth quarter of 2011, our proportionate share could be as much as approximately $45 million. The actual amount of our proportionate share of such costs could differ significantly and would ultimately be based on the level of pre-service costs at the time of any potential termination. As our Delaware and Maryland divisions have now executed the required reservation rate agreements with TETLP, we believe that the likelihood of terminating the Precedent Agreement and having to reimburse TETLP for our proportionate share of TETLP s pre-service costs is remote.

As of March 31, 2011, we provided a letter of credit for $2.1 million, as required under the Precedent Agreement with TETLP. This letter of credit will not exceed more than the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

On March 17, 2010, our Delaware and Maryland divisions entered into a separate Precedent Agreement with Eastern Shore to extend its mainline by eight miles to interconnect with TETLP at Honey Brook, Pennsylvania. As discussed in Note 3, Rates and Other Regulatory Activities, Eastern Shore completed the extension project in December 2010 and commenced the service in January 2011. The rate for the transportation service on this extension is Eastern Shore s current tariff rate for service in that area.

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TETLP is proceeding with obtaining the necessary approvals, authorizations or exemptions for construction and operation of its portion of the project, including, but not limited to, approval by the FERC. Our Delaware and Maryland divisions require no regulatory approvals or exemptions to receive transmission service from TETLP or Eastern Shore.

As the Eastern Shore and TETLP firm transportation services commence, our Delaware and Maryland divisions incur costs from those services based on the agreed reservation rates, which will become an integral component of the costs associated with providing natural gas supplies to our Delaware and Maryland divisions. The costs from the Eastern Shore and TETLP firm transportation services will be included in the annual GSR filings for each of our respective divisions.

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing a sales tax audit in Florida. As of March 31, 2011, we maintained an accrual of $698,000 related to additional sales taxes and gross receipts taxes owed to various states.

Other Contingency

As of March 31, 2011, we maintained a $750,000 accrual, which was recorded in 2010 based on management s assessment of FPU s current earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in the Come-Back filing (See Note 3, Rates and Other Regulatory Activities, to the Condensed Consolidated Financial Statements for further discussion).

6. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance. The segments are evaluated based on their pre-tax operating income. Our operations 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 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 information about our reportable segments.

For the Three Months Ended March 31, *(in thousands)*	2011	2010
Operating Revenues, Unaffiliated Customers		
Regulated Energy	**$ 84,683**	$ 91,300
Unregulated Energy	**58,750**	59,027
Other	**3,164**	2,933
Total operating revenues, unaffiliated customers	**$ 146,597**	$ 153,260
Intersegment Revenues [1]		
Regulated Energy	**$ 319**	$ 326
Unregulated Energy		242
Other	**194**	187
Total intersegment revenues	**$ 513**	$ 755
Operating Income		
Regulated Energy	**$ 16,309**	$ 17,516
Unregulated Energy	**8,515**	7,760
Other and eliminations	**15**	122
Total operating income	**24,839**	25,398
Other income, net of other expenses	**22**	115
Interest	**2,150**	2,363
Income taxes	**8,964**	9,176
Net income	**$ 13,747**	$ 13,974

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

(in thousands)	March 31, 2011	December 31, 2010
Identifiable Assets		
Regulated energy	**$ 509,275**	$ 520,192
Unregulated energy	**109,375**	113,039
Other	**37,652**	37,762
Total identifiable assets	**$ 656,302**	$ 670,993

Our operations are almost entirely domestic. Our advanced information services subsidiary, BravePoint, has infrequent transactions in foreign countries, primarily Canada, which are denominated and paid in U.S. dollars.

These transactions are immaterial to the consolidated revenues.

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7. Employee Benefit Plans

Net periodic benefit costs for our pension and postretirement benefits plans for the three months ended March 31, 2011 and 2010 are set forth in the following table:

	Chesapeake Pension Plan		**FPU Pension Plan**		**Chesapeake SERP**		**Chesapeake Postretirement Plan**		**FPU Medical Plan**	
For the Three Months Ended March 31,	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
(in thousands)										
Service Cost	**$**	$	**$**	$	**$**	$	**$**	$	**$ 26**	$ 28
Interest Cost	**130**	145	**671**	638	**27**	34	**15**	30	**39**	34
Expected return on plan assets	**(101)**	(106)	**(684)**	(619)						
Amortization of prior service cost	**(1)**	(1)			**5**	5				
Amortization of net loss	**39**	39			**10**	16		15	**5**	
Net periodic cost (benefit)	**67**	77	**(13)**	19	**42**	55	**15**	45	**70**	62
Settlement expense	**217**									
Amortization of pre-merger regulatory asset				317					**2**	3
Total periodic cost	**$ 284**	$ 77	**$ (13)**	$ 336	**$ 42**	$ 55	**$ 15**	$ 45	**$ 72**	$ 65

We expect to record pension and postretirement benefit costs of approximately $1.9 million for 2011. Included in that amount is a pension settlement expense of $217,000 recorded in the first quarter of 2011 related to a lump-sum pension distribution of $844,000 from the Chesapeake Pension Plan in January 2011 and $219,000 of an estimated settlement expense in July 2011 related to a lump-sum distribution from the Chesapeake SERP. Also included in that amount 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 $6.5 million and $6.7 million at March 31, 2011 and December 31, 2010, respectively.

During the three months ended March 31, 2011, we contributed $68,000 and $263,000 to the Chesapeake and FPU pension plans, respectively. We expect to contribute $205,000 and $1.3 million to the Chesapeake and FPU pension plans, respectively, during the year 2011.

The Chesapeake SERP, the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake SERP for the three months ended March 31, 2011, were $22,000; for the year 2011, such benefits paid are expected to be approximately $853,000, which includes the expected lump-sum distribution of $765,000 as mentioned above. Cash benefits paid for the Chesapeake Postretirement Plan, primarily for medical claims for the three months ended March 31, 2011, totaled $24,000; for the year 2011, we have estimated that approximately $96,000 will be paid for such benefits. Cash benefits paid for the FPU Medical Plan, primarily for medical claims for the three months ended March 31, 2011, totaled $11,000; for the year 2011, we have estimated that approximately $158,000 will be paid for such benefits.

In connection with the lump-sum pension distribution from the Chesapeake Pension Plan in January 2011 and related settlement accounting, we re-measured the assets and obligations of the Chesapeake Pension Plan. The assumptions used for the discount rate to calculate the benefit obligation remained unchanged at five percent. The average expected return on plan assets also did not change and remained at six percent.

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8. Investments

The investment balance at March 31, 2011, represents: (a) a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan, (b) a Rabbi Trust related to a stay bonus agreement with a former executive, and (c) investments in equity securities. We classify these investments as trading securities and report them at their fair value. Any unrealized gains and losses, net of other expenses, are included in other income in the condensed consolidated statements of income. We also have an associated liability that is recorded and adjusted each month for the gains and losses incurred by the Rabbi Trusts. At March 31, 2011 and December 31, 2010, total investments had a fair value of $3.8 million and $4.0 million, respectively.

9. Share-Based Compensation

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan (DSCP) and the 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 primarily based on the fair value of the grant on the date it was awarded.

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, 2011 and 2010:

For the Three Months Ended March 31,	**2011**	2010
(in thousands)		
Directors Stock Compensation Plan	**$ 84**	$ 64
Performance Incentive Plan	**245**	269
Total compensation expense	**329**	333
Less: tax benefit	**132**	134
Share-Based Compensation amounts included in net income	**$ 197**	$ 199

Directors Stock Compensation Plan

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 of the shares issued and amortize the expense equally over a service period of one year. In January 2011, 304 shares were granted to our former Chief Executive Officer John Schimkaitis, under the DSCP as he retired from the Company and began his service as a non-executive Vice Chairman of the Board.

	Number of Shares	**Weighted Average Grant Date Fair Value**
Outstanding December 31, 2010		
Granted	304	$ 41.54
Vested	304	$ 41.54
Forfeited		
Outstanding March 31, 2011		

At March 31, 2011, there was $28,000 of unrecognized compensation expense related to the DSCP awards that is expected to be recognized over the remaining directors service periods ending April 30, 2011.

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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, 2011:

		Number of Shares		Weighted Average Fair Value
Outstanding	December 31, 2010	101,150	$	28.78
Granted		41,664		39.81
Vested		31,400		27.63
Fortfeited		24,000		29.31
Expired				
Outstanding	March 31, 2011	87,414	$	34.31

In January 2011, the Board of Directors granted awards under the PIP for 41,664 shares. The shares granted in January 2011 are multi-year awards, of which 10,500 shares will vest at the end of the two-year service period, or December 31, 2012. The remaining 31,164 shares will vest at the end of the three-year service period, or December 31, 2013. These awards are earned based upon the successful achievement of long-term goals, growth and financial results, which comprised 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 of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

In conjunction with his retirement, our former Chief Executive Officer forfeited 24,000 shares, which represents the shares awarded under the PIP in January 2009 for the performance period ending December 31, 2011 and in January 2010 for the performance period ending December 31, 2012, that had not vested.

At March 31, 2011, the aggregate intrinsic value of the PIP awards was $1.9 million.

10. 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 and propane. Our natural gas and propane distribution operations have entered into agreements with suppliers to purchase natural gas 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, 2011, our natural gas and propane distribution operations did not have any outstanding derivative contracts.

Xeron, our propane wholesale and marketing operation, 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, 2011, we had the following outstanding trading contracts which we accounted for as derivatives:

At March 31, 2011	Quantity in Gallons	Estimated Market Prices			Weighted Average Contract Prices	
Forward Contracts						
Sale	11,844,000	$	1.0800	$1.4525	$	1.3405

Purchase	12,054,000	$ 1.1200	$1.4500	$ 1.3222

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire during or prior to the fourth quarter of 2011.

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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, 2011 and December 31, 2010, are the following:

		Asset Derivatives	
		Fair Value	
(in thousands)	**Balance Sheet Location**	**March 31, 2011**	**December 31, 2010**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	**$ 339**	$ 1,642
Put option [1]	Mark-to-market energy assets		
Total asset derivatives		**$ 339**	$ 1,642

		Liability Derivatives	
		Fair Value	
(in thousands)	**Balance Sheet Location**	**March 31, 2011**	**December 31, 2010**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ 107**	$ 1,492
Total liability derivatives		**$ 107**	$ 1,492

(1) We purchased a put option for the Pro-Cap (propane price cap) Plan in October 2010. The put option, which expired in January 2011, had a fair value of $0 at December 31, 2010.

The effects of gains and losses from derivative instruments on the condensed consolidated statements of income are the following:

		Amount of Gain (Loss) on Derivatives:	
	Location of Gain (Loss) on Derivatives	**For the Three Months March 31,**	
(in thousands)		**2011**	**2010**
Derivatives not designated as hedging instruments:			
Put Option[1] [2]	Cost of Sales	**$**	$
Unrealized gain on forward contracts	Revenue	**83**	215
Total		**$ 83**	$ 215

(1) We purchased a put option for the Pro-Cap Plan in October 2010. The put option, which expired in January and February 2011, had a fair value of $0 at December 31, 2010.

(2) We purchased a put option for the Pro-Cap Plan in September 2009. The put option, which expired on March 31, 2010, had a fair value of $0 at March 31, 2010

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

(in thousands)	Location of Gain (Loss) on Derivatives	Amount of Trading Revenue For the Three Months Ended March 31, 2011	2010
Realized gain on forward contracts	Revenue	**$ 907**	$ 677
Unrealized gain on forward contracts	Revenue	**83**	215
Total		**$ 990**	$ 892

11. 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).

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, 2011:

		Fair Value Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments	$ 3,835	$ 3,835	$	$
Mark-to-market energy assets	$ 339	$	$ 339	$
Liabilities:				
Mark-to-market energy liabilities	$ 107	$	$ 107	$

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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 December 31, 2010:

		Fair Value Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments	$ 4,036	$ 4,036	$	$
Mark-to-market energy assets, including put option	$ 1,642	$	$ 1,642	$
Liabilities:				
Mark-to-market energy liabilities	$ 1,492	$	$ 1,492	$

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of March 31, 2011 and December 31, 2010:

Level 1 Fair Value Measurements:

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

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 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.

At March 31, 2011, 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 carrying value of these financial assets and liabilities approximates fair value due to their short maturities and because interest rates approximate current market rates for short-term debt.

At March 31, 2011, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $98.8 million, compared to a fair value of $110.5 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, 2010, long-term debt, including the current maturities, had a carrying value of $98.9 million, compared to the estimated fair value of $113.4 million.

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12. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	March 31, 2011	December 31, 2010
FPU secured first mortgage bonds:		
9.57% bond, due May 1, 2018	**$ 7,248**	$ 7,248
10.03% bond, due May 1, 2018	**3,986**	3,986
9.08% bond, due June 1, 2022	**7,950**	7,950
Uncollateralized senior notes:		
6.85% note, due January 1, 2012	**1,000**	1,000
7.83% note, due January 1, 2015	**8,000**	8,000
6.64% note, due October 31, 2017	**19,091**	19,091
5.50% note, due October 12, 2020	**20,000**	20,000
5.93% note, due October 31, 2023	**30,000**	30,000
Convertible debentures:		
8.25% due March 1, 2014	**1,256**	1,318
Promissory note	**230**	265
Total long-term debt	**98,761**	98,858
Less: current maturities	**(9,196)**	(9,216)
Total long-term debt, net of current maturities	**$ 89,565**	$ 89,642

On June 29, 2010, we entered into an agreement with an existing senior note holder to issue up to $36 million in uncollateralized senior notes. We expect to use $29 million of the uncollateralized senior notes to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU bonds. These redemptions occurred in January 2010 and have been financed by short-term loan facilities. The terms of the agreement require us to issue $29 million of the $36 million in uncollateralized senior notes committed by the lender on or before July 9, 2012, with a 15-year term at a rate ranging from 5.28 percent to 6.13 percent based on the timing of the issuance. The remaining $7 million will be issued prior to May 3, 2013, at a rate ranging from 5.28 percent to 6.43 percent based on the timing of the issuance. These notes, when issued, will have similar covenants and default provisions as the existing senior notes and will have an annual principal payment beginning in the sixth year after the issuance.

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, 2010, 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. You can typically identify forward-looking statements by the use of forward-looking words, such as project, believe, expect, anticipate, intend, plan, estimate, continue, potential, forecast or other si or conditional verbs such as may, will, should, would or could. These statements represent our intentions, 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;
- industrial, commercial and residential growth or contraction in our service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes and ice storms;
- 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;
- 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 market prices of equity securities and resultant cash funding requirements for our defined benefit pension plans;
- the creditworthiness of counterparties with which we are engaged in transactions;
- growth in opportunities for our business units;
- the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to manage and maintain key customer relationships;
- the ability to maintain key supply sources;

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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;
changes in technology affecting our advanced information services business; and
operation and litigation risks that may not be covered by insurance.

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;
utilizing our expertise across our various businesses to improve overall performance;
enhancing marketing channels to attract new customers;
providing reliable and responsive customer service to retain existing customers;
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 natural gas and propane is normally highest due to colder temperatures.

The following discussions and those later in the document on operating income and segment results include 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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Overview and Highlights

Our net income for the quarter ended March 31, 2011 was $13.7 million, or $1.43 per share (diluted). This represents a decrease of $227,000, or $0.04 per share (diluted), compared to a net income of $14.0 million, or $1.47 per share (diluted), as reported in the same period in 2010.

For the Three Months Ended March 31,	**2011**	**2010**	**Increase (decrease)**
(in thousands except per share)			
Business Segment:			
Regulated Energy	**$ 16,309**	$ 17,516	$ (1,207)
Unregulated Energy	**8,515**	7,760	755
Other	**15**	122	(107)
Operating Income	**24,839**	25,398	(559)
Other Income	**22**	115	(93)
Interest Charges	**2,150**	2,363	(213)
Income Taxes	**8,964**	9,176	(212)
Net Income	**$ 13,747**	$ 13,974	$ (227)
Earnings Per Share of Common Stock			
Basic	**$ 1.44**	$ 1.48	$ (0.04)
Diluted	**$ 1.43**	$ 1.47	$ (0.04)

Key Factors Affecting Our Businesses

The following is a summary of key factors affecting our businesses and their impacts on our results in the first quarter of 2011. More detailed analysis of our results by segment is provided in the following section.

Weather. Warmer temperatures on the Delmarva Peninsula and in Florida during the first quarter of 2011, compared to the same period in 2010, decreased gross margin of the natural gas, electric and propane distribution operations by approximately $2.1 million. The largest portion of this decline was attributable to significantly warmer weather in Florida. Heating degree-days decreased by four percent, or 98 heating degree-days, on the Delmarva Peninsula and by 44 percent, or 413 heating degree-days, in Florida during the first quarter of 2011, compared to the same quarter in 2010. The decrease in the period-over-period heating degree-days was due primarily to significantly colder weather experienced in Florida in the first quarter of 2010, when we experienced temperatures that were 419 heating degree-days, or 82 percent, colder than normal.

Compared to the 10-year historical average of heating degree-days, which we use as the measure of normal weather for this analysis, the weather on the Delmarva Peninsula in the first quarter of 2011 was three percent colder than normal (69 more heating degree-days) while the weather in Florida was eight percent warmer than normal (44 fewer heating degree-days). We estimate that approximately $369,000 in lower gross margin was recognized in the first quarter of 2011 due to the weather, which overall was warmer than normal.

Growth. In January 2011, Eastern Shore, our natural gas transmission subsidiary, commenced new transportation services on the eight-mile mainline extension to interconnect with the Texas Eastern Transmission pipeline system, which generated gross margin of $542,000 in the first quarter of 2011. These new services have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, providing estimated gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million thereafter.

For the Delmarva natural gas distribution operation, the addition of 12 large commercial and industrial customers since the second half of 2010 generated $249,000 in additional gross margin during the first quarter of 2011, compared to the same quarter in 2010. These new customers are expected to generate annual margin of $1.0 million in

2011, compared to $196,000 of gross margin generated from these customers in 2010. Also generating additional gross margin of $166,000 for the Delmarva natural gas distribution operation for the first quarter of 2011 was growth in residential customers of two percent.

In March 2011, we signed new agreements to serve Beebe Medical Center and SPI Pharma, both located in Lewes, Delaware. Gross margin from these customers is expected to equate to approximately 1,000 residential heating customers with service expected to begin in the fall of 2011. Providing natural gas distribution service in Lewes requires us to extend our natural gas distribution infrastructure by approximately 12 miles, which will provide the foundation to serve new customers in and around the Lewes area and to extend our service farther to other nearby beach areas.

We are also pursuing the extension of natural gas service to Worcester County, Maryland, in response to increasing community interest in clean-burning, environmentally friendly natural gas. Pending receipt of the necessary approvals, natural gas could be available in Worcester County as early as the end of this year. As a first step toward obtaining these approvals, on April 19, 2011, Worcester County approved a non-exclusive natural gas franchise for our Maryland division.

For the Florida natural gas distribution operation, customer growth of two percent generated additional gross margin of $200,000 in the first quarter of 2011, compared to the same quarter in 2010.

Rates and Regulatory Matters. Eastern Shore s base rate proceeding, which was filed with the FERC on December 30, 2010, is still underway. Eastern Shore expects this proceeding to be completed in 2011.

As part of our rate case settlement in Florida in 2010, the Florida PSC required us to submit a Come-Back filing, detailing all known benefits, synergies, cost savings and cost increases resulting from the merger with FPU. We submitted this filing on April 29, 2011. We are requesting the recovery, through rates, of approximately $34.2 million in acquisition adjustment (the price paid in excess of the book value) and $2.2 million in merger-related costs. In the past, the Florida PSC has allowed recovery of an acquisition adjustment under certain circumstances to provide an incentive for larger utilities to purchase smaller utilities. The Florida PSC requires a company seeking recovery of the acquisition adjustment and merger-related costs to demonstrate that customers will benefit from the acquisition. They use a five factor test to determine if the customers are benefitting from the transaction. The five factors are: (a) increased quality of service; (b) lower operating costs; (c) increased ability to attract capital for improvements; (d) lower overall cost of capital; and (e) more professional and experienced managerial, financial, technical and operational resources. With respect to lower costs, the Florida PSC effectively requires that the synergies be sufficient to offset the rate impact of the recovery of the acquisition adjustment and merger-related costs.

If the Florida PSC approves recovery of the acquisition adjustment and merger-related costs, we would be able to classify these amounts as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. Additionally, we would calculate our rate of return based upon this higher level of investment which effectively enables us to earn a return on our investment. We would also be able to amortize the acquisition adjustment and merger-related costs over thirty and five years, respectively. Amortization expense would be included in the calculation of our rates.

Our earnings may be reduced by as much as $1.6 million annually for the amortization expense (approximately $1.3 million is non-tax-deductible) until 2014 and $1.1 million annually (non-tax deductible) thereafter until 2039. Over the long-term, though, the inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these regulatory assets through amortization expense will increase our earnings and cash flows above what we would have otherwise been able to achieve.

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If the Florida PSC does not allow recovery of the acquisition adjustment and merger-related costs, there is some likelihood that we would have to reduce rates in the state of Florida, which could adversely affect our future earnings. We continue to maintain a $750,000 accrual. This accrual was recorded in 2010 based on management s assessment of FPU s current earnings and regulatory risk to its earnings associated with possible Florida PSC action related to our requested recovery and the matters set forth in this filing.

Propane Prices. Higher price volatility and trading volumes in the wholesale propane market resulted in a 60 percent increase in Xeron s trading volumes during the first quarter of 2011, compared to the same quarter in 2010, which contributed to a period-over-period gross margin increase of $97,000.

The propane distribution operations generated additional gross margin of $969,000 from higher margins per gallon in the first quarter of 2011, compared to the same quarter in 2010, as margins per gallon returned to more normal levels. Significantly colder temperatures during the first quarter of 2010 increased customer consumption and led to the propane distribution operations having to purchase additional propane supply at increased costs, resulting in a higher propane inventory cost and lower margins per gallon during that period. The absence of much colder than normal temperatures during the first quarter of 2011 and fewer spot purchases during the peak heating season resulted in margins per gallon returning to more normal levels in 2011.

Other Operating Expenses. Our other operating expenses increased by $971,000 in the first quarter of 2011, compared to the same quarter in 2010, largely due to: (a) an increase in depreciation expense of $150,000 and asset removal costs of $169,000 from capital investments made in 2010, (b) one-time severance and pension settlement charges totaling $295,000, (c) increased expenses related to on-going pipeline integrity projects for Eastern Shore of $246,000, (d) increased bad debt and collection expense of $100,000 primarily as a result of the reversal of bad debt expense recorded in the first quarter of 2010 for a recovery of a previously reserved receivable from a Florida electric customer in bankruptcy, and (e) additional expenses of $68,000 from the purchase of the operating assets of Indiantown Company in August 2010. These increases were partially offset by lower expenses in Florida.

In the second quarter of 2011, we expect to record a one-time charge of approximately $600,000 related to severance that will be paid to approximately 30 employees, who are expected to participate in the voluntary reduction in workforce program in Florida, as we continue to integrate our Florida operations.

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Regulated Energy

For the Three Months Ended March 31,	2011	2010	Increase (decrease)
(in thousands)			
Revenue	**$ 85,002**	$ 91,626	$ (6,624)
Cost of sales	**47,990**	54,263	(6,273)
Gross margin	**37,012**	37,363	(351)
Operations & maintenance	**14,310**	13,531	779
Depreciation & amortization	**4,166**	4,009	157
Other taxes	**2,227**	2,307	(80)
Other operating expenses	**20,703**	19,847	856
Operating Income	**$ 16,309**	$ 17,516	$ (1,207)
Weather and Customer analysis			
Delmarva Peninsula			
Heating degree-days (HDD):			
Actual	**2,445**	2,543	(98)
10-year average	**2,376**	2,336	40
Per residential customer added:			
Estimated gross margin	**$ 375**	$ 375	$ 0
Estimated other operating expenses	**$ 111**	$ 105	$ 6
Florida			
HDD:			
Actual	**520**	933	(413)
10-year average	**564**	514	50
Cooling degree-days:			
Actual	**80**	3	77
10-year average	**67**	72	(5)
Residential Customer Information			
Average number of customers:			
Delmarva natural gas distribution	**49,312**	48,183	1,129
Florida natural gas distribution	**61,547**	60,482	1,065
Florida electric distribution	**23,589**	23,531	58
Total	**134,448**	132,196	2,252

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Operating income for the regulated energy segment decreased by approximately $1.2 million, or seven percent, in the first quarter of 2011, compared to the same quarter in 2010, which was due to a gross margin decrease of $351,000 and an increase in other operating expenses of $856,000.

Gross Margin

Gross margin for our regulated energy segment decreased by $351,000, or one percent, in the first quarter of 2011 compared to the same quarter in 2010.

Our Delmarva natural gas distribution operation generated an increase in gross margin of $441,000 in the first quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- Two percent growth in residential customers and the addition of several large commercial and industrial customers for our Delmarva natural gas distribution operations generated a $455,000 increase in gross margin. Residential, commercial and industrial growth by our Delaware and Maryland divisions generated $166,000, $27,000 and $262,000, respectively, in gross margin for the quarter. Since the second half of 2010, our Delmarva natural gas distribution operations have added 12 large commercial and industrial customers with total expected annualized margin contribution of $1.0 million in 2011, of which $249,000 has been reflected in the first quarter results. The same customers generated $196,000 of gross margin following their addition in 2010.
- An increase in non-weather-related customer consumption, primarily by residential customers of our Delaware division, increased gross margin by $176,000.
- The increase in gross margin in the first quarter was offset by $118,000 due to the warmer weather on the Delmarva Peninsula as heating degree-days decreased by 98, or four percent, in the first quarter of 2011, compared to the same quarter in 2010. This decrease in gross margin is primarily related to our Delaware division, as residential heating rates for our Maryland division are weather-normalized, and we typically do not experience an impact on gross margin from the weather for our residential customers in Maryland.
- In addition, a decrease in gross margin of $76,000 was due primarily to a change in customer rates and rate classes.

Gross margin for our Florida natural gas distribution operation decreased by $1.1 million in the first quarter of 2011 compared to the same quarter in 2010. The factors contributing to this decrease were as follows:

- Warmer weather reduced gross margin by $1.4 million in the first quarter of 2011, compared to the same quarter in 2010. Heating degree-days decreased by 413, or 44 percent. This decrease was due primarily to weather in the first quarter of 2010 being 82 percent (419 heating degree-days) colder than normal. Comparing to normal, the weather in the first quarter of 2011 was eight percent warmer (44 heating degree-days). The warmer-than-normal weather in the first quarter of 2011 represents approximately $477,000 in lower gross margin in Florida.
- Two percent customer growth in the Florida natural gas distribution operation generated additional gross margin of $200,000 in the first quarter of 2011, compared to the same quarter in 2010.
- 700 new customers added as a result of the purchase of the operating assets of Indiantown Gas Company in August 2010 generated $182,000 in gross margin in the first quarter of 2011.

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Our natural gas transmission operations achieved gross margin growth of $648,000 in the first quarter of 2011 compared to the same quarter in 2010. The factors contributing to this increase were as follows:

New transportation services implemented by Eastern Shore in May 2010 and November 2010 as result of its system expansion projects generated an additional $143,000 of gross margin in the first quarter of 2011, compared to 2010. These expansion projects added 2,666 Mcfs of capacity per day with estimated annual gross margin of $574,000 in 2011. These projects generated $216,000 of gross margin in 2010.

New transportation services implemented by Eastern Shore in January 2011 for Chesapeake s Delaware and Maryland divisions generated an additional $542,000 of gross margin in the first quarter. These new services have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, providing estimated annual gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million thereafter. These new services were added as a result of Eastern Shore s completion of the eight-mile mainline extension in December 2010 to interconnect with TETLP s pipeline system.

The foregoing increases to gross margin were offset by the expiration of two small firm transportation service contracts in April 2010, decreasing gross margin by $40,000 in the first quarter of 2011.

Gross margin for our Florida electric distribution operation decreased by $322,000 in the first quarter of 2011, compared to the same quarter in 2010, due primarily to warmer weather.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $856,000, or four percent, in the first quarter of 2011 compared to the same quarter in 2010, due largely to the following factors: (a) increased depreciation expense of $133,000 and asset removal costs of $169,000 from capital investments made in 2010; (b) increased expenses related to on-going pipeline integrity projects for Eastern Shore of $246,000; (c) increased bad debt expense of $177,000 primarily as a result of the reversal of bad debt expense recorded in the first quarter of 2010 for recovery of a previously reserved receivable from a Florida electric customer in bankruptcy; (d) one-time severance and pension settlement charges totaling $204,000 in the first quarter of 2011; and (e) additional expenses of $68,000 from the purchase of the operating assets of Indiantown Gas Company. These increases were partially offset by property tax savings in Delaware and lower expenses in Florida.

Unregulated Energy

For the Three Months Ended March 31,	**2011**	**2010**	**Increase (decrease)**
(in thousands)			
Revenue	**$ 58,750**	$ 59,269	$ (519)
Cost of sales	**42,755**	43,958	(1,203)
Gross margin	**15,995**	15,311	684
Operations & maintenance	**6,232**	6,026	206
Depreciation & amortization	**755**	1,046	(291)
Other taxes	**493**	479	14
Other operating expenses	**7,480**	7,551	(71)
Operating Income	**$ 8,515**	$ 7,760	$ 755
Weather Analysis Delmarva Peninsula			
Actual HDD	**2,445**	2,543	(98)
10-year average HDD	**2,376**	2,336	40

Operating income for the unregulated energy segment increased by approximately $755,000, or 10 percent, in the first quarter of 2011, compared to the same quarter in 2010, largely attributable to a gross margin increase of $684,000, and a decrease in other operating expenses of $71,000.

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Gross Margin

Gross margin for our unregulated energy segment increased by $684,000, or four percent, in the first quarter of 2011, compared to the same quarter in 2010.

Our Delmarva propane distribution operation experienced an increase in gross margin of $885,000 in the first quarter of 2011, compared to the same quarter in 2010. The factors contributing to this increase were as follows:

- Additional gross margin of $775,000 was generated by higher margins per gallon in the first quarter of 2011, compared to the same quarter in 2010, as margins per gallon returned to more normal levels. Significantly colder temperatures during the first quarter of 2010 increased customer consumption and led to the propane distribution operations having to purchase additional propane supply at increased costs, resulting in a higher propane inventory cost and lower margins per gallon during that period. The absence of much colder than normal temperatures during the first quarter of 2011 and fewer spot purchases during the peak heating season resulted in margins per gallon returning to more normal levels in 2011.
- A one-time gain of $575,000 was recorded in the first quarter of 2011, as a result of our share of proceeds received from an antitrust litigation settlement with a major propane supplier.
- The warmer weather on the Delmarva Peninsula and a decrease in propane deliveries to bulk customers decreased gross margin by $403,000. Heating degree-days decreased by 98, or four percent, in the first quarter of 2011, compared to the same quarter in 2010. The decline in deliveries is primarily related to the timing of deliveries to bulk customers year-over-year.

Our Florida propane distribution operations experienced a decrease in gross margin of $226,000 in the first quarter of 2011 compared to the same quarter in 2010. A decrease in customer consumption, due primarily to significantly warmer weather and the timing of bulk deliveries to customers, contributed to this decrease. Partially offsetting this decline was an increase in margins per gallon and an additional gross margin generated from new wholesale operations in the first quarter of 2011.

Xeron, the Company s propane wholesale marketing subsidiary, generated $97,000 of increase in gross margin during the first quarter of 2011, compared to the same quarter in 2010, due primarily to increased trading activities.

Gross margin generated by PESCO, the Company s natural gas marketing subsidiary, remained substantially unchanged in the first quarter of 2011, compared to the same quarter in 2010.

Merchandise sales in Florida decreased in the first quarter of 2011, compared to the same period in 2010, resulting in lower gross margin of $83,000.

Other Operating Expenses

Other operating expenses for the unregulated energy segment remained substantially unchanged as it decreased slightly by $71,000 in the first quarter of 2011, compared to the same quarter in 2010.

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Other

For the Three Months Ended March 31,	2011	2010	Increase (decrease)
(in thousands)			
Revenue	**$ 2,845**	$ 2,365	$ 480
Cost of sales	**1,534**	1,133	401
Gross margin	**1,311**	1,232	79
Operations & maintenance	**997**	857	140
Depreciation & amortization	**100**	73	27
Other taxes	**199**	180	19
Other operating expenses	**1,296**	1,110	186
Operating Income Other	**15**	122	(107)
Operating Income Eliminations			
Operating Income	**$ 15**	$ 122	$ (107)

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

Operating income for the other segment decreased by approximately $107,000 in the first quarter of 2011, compared to the same quarter in 2010, which was attributable to a gross margin increase of $79,000, offset by an operating expense increase of $186,000.

Gross margin

The gross margin increase of $79,000 for our other segment was primarily a result of an increase in product sales, offset partially by lower consulting revenues for BravePoint, our advanced information services subsidiary.

Operating expenses

The other operating expenses increase of $186,000 was due primarily to an increase of $194,000 in other operating expenses of BravePoint as a result of increased payroll and benefit costs in addition to increased amortization expense associated with BravePoint s new product, ProfitZoom , an integrated system designed specifically for the fire suppression and specialty contracting industries, which includes financial, job costing and service management modules.

Interest Expense

Interest expense for the quarter ended March 31, 2011 decreased by approximately $213,000, or nine percent, compared to the same period in 2010. The following factors contributed to the decrease in interest expense:

In January 2010, we redeemed two series of First Mortgage Bonds, the 4.90 percent and 6.85 percent series, by using a new short-term loan facility. These redemptions reduced the amount of FPU s secured long-term debt. Borrowing under the short-term facility lowered interest expense by $57,000 in the first quarter of 2011, compared to the same period in 2010.

Other long-term interest expense decreased by $165,000 in the first quarter of 2011, compared to the same period in 2010, due to scheduled repayments.

Other short-term interest expense remained substantially unchanged. Higher short-term borrowing rates during the first quarter of 2011 were offset by lower working capital requirements.

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We have entered into an arrangement with an existing unsecured senior note holder to refinance the short-term loan facility used to redeem two series of First Mortgage Bonds as Chesapeake unsecured senior notes. If refinanced prior to July 8, 2011, these new unsecured senior notes will be issued at 5.68 percent and will result in an increase in interest expense of $549,000 in the second half of 2011.

Income Taxes

We recorded an income tax expense of $9.0 million for the quarter ended March 31, 2011, compared to $9.2 million for the quarter ended March 31, 2010. The period-over-period decrease in income tax expense is primarily a function of lower earnings for the period.

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 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.

Capital expenditures are one of our largest capital requirements. We have budgeted $51.7 million for capital expenditures during 2011. This amount includes $43.6 million for the regulated energy segment, $3.7 million for the unregulated energy segment and $4.4 million for the other segment. The amount for the regulated energy segment includes estimated capital expenditures for expansion and improvement of facilities for the following: (a) natural gas distribution operation ($25.4 million); (b) natural gas transmission operation ($12.5 million); and (c) electric distribution operation ($5.7 million). The amount for the unregulated energy segment includes estimated capital expenditures for the propane distribution operations for customer growth and replacement of equipment. The amount for the other segment includes an estimated capital expenditure of $245,000 for the advanced information services operation, with the remaining balance for other general plant, computer software and hardware. Depending on the progress of various natural gas distribution and transmission growth and expansion initiatives, our capital expenditure budget in 2011 may increase by as much as $30 million. We expect to fund the 2011 capital expenditures program from short-term borrowing, 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.

Capital Structure

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of March 31, 2011 and December 31, 2010:

(in thousands)		**March 31, 2011**			December 31, 2010	
Long-term debt, net of current maturities	**$**	**89,565**	**27%**	$	89,642	28%
Stockholders equity		**237,015**	**73%**		226,239	72%
Total capitalization, excluding short-term debt	**$**	**326,580**	**100%**	$	315,881	100%

(in thousands)		**March 31, 2011**			December 31, 2010	
Short-term debt	**$**	**41,427**	**11%**	$	63,958	16%
Long-term debt, including current maturities		**98,761**	**26%**		98,858	25%
Stockholders equity		**237,015**	**63%**		226,239	59%
Total capitalization, including short-term debt	**$**	**377,203**	**100%**	$	389,055	100%

Short-term Borrowings

Our outstanding short-term borrowings at March 31, 2011 and December 31, 2010 were $41.4 million and $64.0 million, respectively, at the weighted average interest rates of 1.54 percent and 1.77 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, 2011, 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 $85.0 million of short-term debt, as required, from these unsecured bank lines of credit.

Our outstanding borrowings under these unsecured bank lines of credit at March 31, 2011 and December 31, 2010 were $11.0 million and $30.8 million, respectively, at the weighted average interest rates of 1.51 percent and 1.65 percent, respectively. In addition to the four unsecured bank lines of credit, we entered into a new credit facility for $29.1 million with an existing lender in March 2010. We borrowed $29.1 million under this new credit facility to finance the early redemption of the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds. The interest rate on this borrowing at March 31, 2011 and December 31, 2010 was fixed at 1.55 percent. This credit facility expires on October 31, 2011.

On June 29, 2010, we entered into an agreement with an existing senior note holder to issue up to $36 million in uncollateralized senior notes. We expect to use $29 million of the uncollateralized senior notes to permanently finance the early redemption of the 6.85 percent and 4.90 percent series of FPU bonds previously discussed. If refinanced prior to July 8, 2011, these new uncollateralized senior notes will be issued at 5.68 percent and result in an increase in interest expense of $549,000 in the second half of 2011. We also expect to use the remaining $7 million to redeem additional FPU secured first mortgage bonds in 2013.

Cash Flows Provided By Operating Activities

Cash flows provided by operating activities were as follows:

For the Three Months Ended March 31,	**2011**	**2010**
(in thousands)		
Net Income	**$ 13,747**	$ 13,974
Non-cash adjustments to net income	**15,606**	6,194
Changes in assets and liabilities	**4,917**	26,231
Net cash provided by operating activities	**$ 34,270**	$ 46,399

During the three months ended March 31, 2011 and 2010, net cash flow provided by operating activities was $34.3 million and $46.4 million, respectively, a period-over-period decrease of $12.1 million. Significant operating activities reflected in the change in cash flows provided by operating activities are as follows:

Net cash flows from trading receivables and payables by Xeron, our propane wholesale marketing subsidiaries, decreased by $6.3 million due to the timing of propane trading activities. Xeron collects from and pays to its counterparties all of the receivables and payables from trading activities within one month.

Net cash flows from customer deposits decreased by $2.8 million, due primarily to a large deposit received from a new industrial customer during the first quarter of 2010, which increased the cash flow for that period.

Net cash flows from accrued compensation decreased by $1.0 million as a result of increased payments for incentive compensation and severance in the first quarter of 2011, compared to the same period in 2010.

Cash Flows Used in Investing Activities

Net cash flows used in investing activities totaled $8.2 million and $6.8 million during the three months ended March 31, 2011 and 2010, respectively. Cash utilized for capital expenditures was $8.4 million and $6.1 million for the first three months of 2011 and 2010, respectively.

Cash Flows Used by Financing Activities

Cash flows used in financing activities totaled $25.7 million and $32.3 million for the first three months of 2011 and 2010, respectively. Significant financing activities reflected in the change in cash flows used by financing activities are as follows:

During the first three months of 2011 we had a net repayment of $19.7 million under our line of credit agreements related to working capital compared to $29.2 million in the same period in 2010. Changes in cash overdrafts decreased by $2.0 million.

We paid $2.8 million and $2.7 million in cash dividends for the three months ended March 31, 2011 and 2010, respectively.

During the first three months of 2010 we issued $29.1 million in short-term term notes and used the proceeds to finance the redemption, in January 2010, of two series of FPU s secured first mortgage bonds prior to their respective maturities.

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Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily the propane wholesale marketing subsidiary and the 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, 2011 was $26.0 million, with the guarantees expiring on various dates in 2011.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $441,000, which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various insurance outstanding policies. Although we recently changed our primary insurance company, we still have an outstanding letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2011. There have been no draws on these letters of credit as of March 31, 2011. 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 $2.1 million under the Precedent Agreement with TETLP. The letter of credit is expected to increase quarterly as TETLP s pre-service costs increase. The letter of credit will not exceed the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

Contractual Obligations

There have not been any material changes in the contractual obligations presented in our 2010 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, 2011.

	Payments Due by Period				
Purchase Obligations	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
(in thousands)					
Commodities (1)	$ 22,962	$ 373	$	$	**$ 23,335**
Propane (2)	15,938				**15,938**
Total Purchase Obligations	**$ 38,900**	**$ 373**	**$**	**$**	**$ 39,273**

(1) In addition to the obligations noted above, the natural gas distribution, the electric distribution 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 $15.9 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 4, Environmental Commitments and Contingencies, to these 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 s; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At March 31, 2011, 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 3, Rates and Other Regulatory Activities, to these unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

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Competition

Our natural gas and electric distribution operations and our natural gas transmission operation compete with other forms of energy, including natural gas, electricity, oil and propane. 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 transmission operation s conversion 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 as 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.

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 industrial 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.

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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 these 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 $98.8 million at March 31, 2011, as compared to a fair value of $110.5 million, based on 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.

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 six million gallons (including leased storage and rail cars) of propane 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 settled by the delivery of natural gas liquids to us or the counter-party or booking out the transaction. Booking out is a procedure for financially settling a contract in lieu of the physical delivery of energy. The propane wholesale marketing operation also enters into futures contracts that are traded on the New York Mercantile Exchange. 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.

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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, 2011 is presented in the following tables.

At March 31, 2011	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	11,844,000	$ 1.0800	$1.4525	$ 1.3405
Purchase	12,054,000	$ 1.1200	$1.4500	$ 1.3222

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

All contracts expire during or prior to the fourth quarter of 2011.

At March 31, 2011 and December 31, 2010, we marked these forward 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, 2011	December 31, 2010
Mark-to-market energy assets	**$ 339**	$ 1,642
Mark-to-market energy liabilities	**$ 107**	$ 1,492

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, 2011. 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, 2011.

Changes in Internal Control over Financial Reporting

During the quarter ended March 31, 2011, 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 5, Other Commitments and Contingencies, of these 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, 2010, 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 presently known to us 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, 2011 through January 31, 2011 [(1)]	242	$ 40.21		
February 1, 2011 through February 28, 2011		$		
March 1, 2011 through March 31, 2011		$		
Total	242	$ 40.21		

(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 M, Employee Benefit Plans of our Form 10-K filed with the Securities and Exchange Commission on March 8, 2011. During the quarter, 242 shares were purchased through the reinvestment of dividends on deferred stock units.

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

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

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Item 6. Exhibits

4.1	Seventeenth Supplemental Indenture entered into by Chesapeake Utilities Corporation and Florida Public Utilities Company, on April 12, 2011, pursuant to which Chesapeake Utilities Corporation guarantees the payment and performance obligations of Florida Public Utilities Company under the Indenture, is filed herewith.
31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, dated May 4, 2011.
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 4, 2011.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 4, 2011.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 4, 2011.

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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 4, 2011