CHESAPEAKE UTILITIES CORP
Form 10-Q
May 07, 2010

Table of Contents

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, 2010

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 9,458,048 shares outstanding as of April 30, 2010.

Table of Contents

Table of Contents

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
ESNG	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
PIPECO	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 States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FDEP	Florida Department of Environmental Protection
Florida PSC	Florida Public Service Commission
IASB	International Accounting Standards Board
Maryland PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
PSC	Public Service Commission
SEC	Securities and Exchange Commission

Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CGS	Community Gas Systems
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per day
GSR	Gas Sales Service Rates
HDD	Heating Degree-Days
Mcf	Thousand Cubic Feet
MWH	Megawatt Hour
MGP	Manufactured Gas Plant
NYSE	New York Stock Exchange
PIP	Performance Incentive Plan
RAP	Remedial Action Plan

Accounting Standard

ASC	FASB Accounting Standards Codification™ (Codification)
ASU	FASB Accounting Standards Update
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards

Table of Contents

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)*	2010	2009
Operating Revenues		
Regulated Energy	**$ 91,626**	$ 52,181
Unregulated Energy	**59,269**	49,394
Other	**2,365**	2,904
Total operating revenues	**153,260**	104,479
Operating Expenses		
Regulated energy cost of sales	**53,768**	32,513
Unregulated energy and other cost of sales	**45,091**	38,709
Operations	**18,695**	12,245
Transaction-related costs	**19**	114
Maintenance	**1,700**	615
Depreciation and amortization	**5,623**	2,384
Other taxes	**2,966**	1,933
Total operating expenses	**127,862**	88,513
Operating Income	**25,398**	15,966
Other income, net of expenses	**115**	33
Interest charges	**2,363**	1,642
Income Before Income Taxes	**23,150**	14,357
Income tax expense	**9,176**	5,764
Net Income	**$ 13,974**	$ 8,593
Weighted-Average Common Shares Outstanding:		
Basic	**9,419,932**	6,832,675
Diluted	**9,524,298**	6,943,129

Earnings Per Share of Common Stock:				
Basic	**$**	**1.48**	$	1.26
Diluted	**$**	**1.47**	$	1.24
Cash Dividends Declared Per Share of Common Stock	**$**	**0.315**	$	0.305

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

Table of Contents

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

For the Three Months Ended March 31, *(in thousands)*	**2010**	2009
Operating Activities		
Net Income	**$ 13,974**	$ 8,593
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**5,623**	2,384
Depreciation and accretion included in other costs	**861**	664
Deferred income taxes, net	**369**	(790)
Unrealized loss (gain) on commodity contracts	**(215)**	1,294
Unrealized loss (gain) on investments	**(51)**	94
Employee benefits	**(272)**	412
Share-based compensation	**333**	241
Other, net	**41**	
Changes in assets and liabilities:		
Sale (purchase) of investments	**(30)**	34
Accounts receivable and accrued revenue	**15,800**	9,217
Propane inventory, storage gas and other inventory	**6,155**	8,527
Regulatory assets	**1,669**	604
Prepaid expenses and other current assets	**1,923**	1,360
Accounts payable and other accrued liabilities	**(12,741)**	(10,940)
Income taxes receivable	**8,580**	6,345
Accrued interest	**949**	1,140
Customer deposits and refunds	**604**	(1,854)
Accrued compensation	**(980)**	(1,608)
Regulatory liabilities	**3,314**	5,357
Other liabilities	**503**	(38)
Net cash provided by operating activities	**46,409**	31,036
Investing Activities		
Property, plant and equipment expenditures	**(6,099)**	(4,124)
Purchase of investments	**(310)**	
Environmental expenditures	**(367)**	(8)
Net cash used in investing activities	**(6,776)**	(4,132)
Financing Activities		
Common stock dividends	**(2,683)**	(1,791)
Issuance (purchase) of stock for Dividend Reinvestment Plan	**152**	(227)
Change in cash overdrafts due to outstanding checks	**(834)**	
Net repayment under line of credit agreements	**(88)**	(23,200)
Repayment of long-term debt	**(28,858)**	(20)

Net cash used in financing activities		**(32,311)**		(25,238)
Net Increase in Cash and Cash Equivalents		**7,322**		1,666
Cash and Cash Equivalents Beginning of Period		**2,828**		1,611
Cash and Cash Equivalents End of Period	**$**	**10,150**	$	3,277

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

Table of Contents

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

Assets *(in thousands, except shares and per share data)*	**March 31, 2010**	**December 31, 2009**
Property, Plant and Equipment		
Regulated energy	**$ 467,147**	$ 463,856
Unregulated energy	**59,066**	61,360
Other	**16,073**	16,054
Total property, plant and equipment	**542,286**	541,270
Less: Accumulated depreciation and amortization	**(111,497)**	(107,318)
Plus: Construction work in progress	**3,720**	2,476
Net property, plant and equipment	**434,509**	436,428
Investments	**2,040**	1,959
Current Assets		
Cash and cash equivalents	**10,150**	2,828
Accounts receivable (less allowance for uncollectible accounts of $1,460 and $1,609, respectively)	**55,165**	70,029
Accrued revenue	**11,877**	12,838
Propane inventory, at average cost	**6,142**	7,901
Other inventory, at average cost	**3,331**	3,149
Regulatory assets	**66**	1,205
Storage gas prepayments	**1,566**	6,144
Income taxes receivable		2,614
Deferred income taxes	**3,324**	1,498
Prepaid expenses	**3,857**	5,843
Mark-to-market energy assets	**198**	2,379
Other current assets	**146**	147
Total current assets	**95,822**	116,575
Deferred Charges and Other Assets		
Goodwill	**34,782**	34,095
Other intangible assets, net	**3,809**	3,951
Long-term receivables	**247**	343
Regulatory assets	**21,936**	19,860
Other deferred charges	**3,799**	3,891
Total deferred charges and other assets	**64,573**	62,140

Total Assets	**$**	**596,944**	$	617,102

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

Table of Contents

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

Capitalization and Liabilities *(in thousands, except shares and per share data)*	**March 31, 2010**	**December 31, 2009**
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 12,000,000 shares)	**$ 4,594**	$ 4,572
Additional paid-in capital	**144,866**	144,502
Retained earnings	**74,205**	63,231
Accumulated other comprehensive loss	**(2,484)**	(2,524)
Deferred compensation obligation	**748**	739
Treasury stock	**(748)**	(739)
Total stockholders equity	**221,181**	209,781
Long-term debt, net of current maturities	**98,988**	98,814
Total capitalization	**320,169**	308,595
Current Liabilities		
Current portion of long-term debt	**8,125**	35,299
Short-term borrowing	**29,100**	30,023
Accounts payable	**37,809**	51,948
Customer deposits and refunds	**25,650**	24,960
Accrued interest	**2,836**	1,887
Dividends payable	**2,974**	2,959
Income taxes payable	**5,901**	
Accrued compensation	**2,493**	3,445
Regulatory liabilities	**12,171**	8,882
Mark-to-market energy liabilities	**118**	2,514
Other accrued liabilities	**10,543**	8,683
Total current liabilities	**137,720**	170,600
Deferred Credits and Other Liabilities		
Deferred income taxes	**68,666**	66,923
Deferred investment tax credits	**170**	193
Regulatory liabilities	**4,179**	4,154
Environmental liabilities	**10,066**	11,104
Other pension and benefit costs	**17,212**	17,505
Accrued asset removal cost Regulatory liability	**33,731**	33,214
Other liabilities	**5,031**	4,814
Total deferred credits and other liabilities	**139,055**	137,907

Total Capitalization and Liabilities	**$**	**596,944**	$	617,102

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

Table of Contents

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

(in thousands, except per share and share data)	Common Stock Number of Shares[(7)]	Common Stock Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2008	**6,827,121**	**$ 3,323**	**$ 66,681**	**$ 56,817**	**$ (3,748)**	**$ 1,549**	**$ (1,549)**	**$ 123,073**
Net Income				15,897				15,897
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [(4)]					7			7
Net Gain [(5)]					1,217			1,217
Total comprehensive income								$ 17,121
Dividend Reinvestment Plan	31,607	15	921					936
Retirement Savings Plan	32,375	16	966					982
Conversion of debentures	7,927	4	131					135
Share based compensation [(1)] [(3)]	7,374	3	1,332					1,335
Deferred Compensation Plan [(6)]						(810)	810	
Purchase of treasury stock	(2,411)						(73)	(73)
Sale and distribution of treasury stock	2,411						73	73
Common stock issued in the merger	2,487,910	1,211	74,471					75,682
Dividends on stock-based compensation				(104)				(104)
Cash dividends [(2)]				(9,379)				(9,379)
Balances at December 31, 2009	**9,394,314**	**4,572**	**144,502**	**63,231**	**(2,524)**	**739**	**(739)**	**209,781**
Net Income				13,974				13,974
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [(4)]					2			2
Net Gain [(5)]					38			38
Total comprehensive income								$ 14,014
Dividend Reinvestment Plan	13,714	6	416					422
Retirement Savings Plan	3,539	2	111					113
Conversion of debentures	2,173	1	36					37
Tax benefit on share based compensation			75					75
Share based compensation [(1)] [(3)]	26,515	13	(274)					(261)
Deferred Compensation Plan [(6)]						9	(9)	
Purchase of treasury stock	(279)						(9)	(9)
Sale and distribution of treasury stock	279						9	9
Dividends on stock-based compensation				(26)				(26)
Cash dividends [(2)]				(2,974)				(2,974)

Balances at March 31, 2010	**9,440,255**	**$ 4,594**	**$ 144,866**	**$ 74,205**	**$ (2,484)**	**$ 748**	**$ (748)**	**$ 221,181**

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

(2) Cash dividends per share for the periods ended March 31, 2010 and December 31, 2009 were $0.315 and $1.250, respectively.

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For the period ended March 31, 2010, the Company withheld 17,695 shares for taxes. We did not issue any shares under PIP in 2009.

(4) Tax expense recognized on the prior service cost component of employees benefit plans for the periods ended March 31, 2010 and December 31, 2009 were approximately $1 and $5, respectively.

(5)

Tax expense recognized on the net gain (loss) component of employees benefit plans for the periods ended March 31, 2010 and December 31, 2009 were $26 and $794, respectively.

(6) In May and November 2009, certain participants of the Deferred Compensation Plan received distributions totaling $883. There were no distributions in the first quarter of 2010.

(7) Includes 28,731 and 28,452 shares at March 31, 2010 and December 31, 2009, 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.

Table of Contents

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, 2010. 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.

As a result of the merger with Florida Public Utilities Company (FPU) in October 2009, we changed our operating segments (see Note 5, Segment Information, for further discussion). We revised the segment information as of and for the three months ended March 31, 2009, to reflect the new segments. We also revised certain presentations and reclassified certain amounts reported in the condensed consolidated statements of income and cash flows for the three months ended March 31, 2009 to conform to current period presentations and classifications. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

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.

Recent Accounting Amendments Yet to be Adopted by the Company

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards (IFRS), a comprehensive series of accounting standards published by the International Accounting Standards Board (IASB). Under the proposed roadmap, we may be required to prepare our financial statements in accordance with IFRS as early as 2014. The SEC will make a determination in 2011 regarding the mandatory adoption of IFRS. In July 2009, the IASB issued an exposure draft of Rate-regulated Activities, which sets out the scope, recognition and measurement criteria, and accounting disclosures for assets and liabilities that arise in the context of cost-of-service regulation, to which our rate-regulated businesses are subject. We will continue to monitor the development of the potential implementation of IFRS.

Other Accounting Amendments Adopted by the Company during the first quarter of 2010

In January 2010, the Financial Accounting Standards Board (FASB) issued FASB Accounting Standards Update (ASU) 2010-06, Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements. This ASU requires certain new disclosures and clarifies certain existing disclosure requirements about fair value measurement, as set forth in FASB Accounting Standards Codification (ASC) Subtopic 820-10. The FASB s objective is to improve these disclosures and, thus, increase the transparency in financial reporting. Specifically, ASU 2010-06 amends ASC Subtopic 820-10 to now require a reporting entity to disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers; and, in the reconciliation for fair value measurements using significant unobservable inputs, a reporting entity should present separate information about purchases, sales, issuances, and settlements. In addition, ASU 2010-06 clarifies certain requirements of the existing disclosures. We adopted the disclosures required by this ASU in the first quarter of 2010, except for disclosures about purchases, sales, issuances, and settlements in the roll-forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. We currently do not have any assets or liabilities that would require Level 3 fair value measurements. Adoption of this ASU did not have an impact on our condensed consolidated financial position and results of operations.

Table of Contents

In April 2010, the FASB issued FASB ASU 2010-12 Income Taxes (Topic 740), Accounting for Certain Tax effects of the 2010 Health Care Reform Acts. This ASU codifies the SEC staff announcement relating to the accounting for the Health Care and Education Reconciliation Act and the Patient Protection and Affordable Care Act, which allows the two Acts to be considered together for accounting purposes. We adopted this ASU in the first quarter of 2010 and have determined that these Acts did not have a material impact on our income tax accounting (see Note 6, Employee Benefits, to these unaudited condensed consolidated financial statements for further discussion).

2. Acquisitions

FPU

On October 28, 2009, we completed the previously announced merger with FPU, pursuant to which FPU became a wholly-owned subsidiary of Chesapeake. The merger was accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer for accounting purposes.

The merger allowed us to become a larger energy company serving approximately 200,000 customers in the Mid-Atlantic and Florida markets, which is twice the number of energy customers we served previously. The merger increased our overall presence in Florida by adding approximately 51,000 natural gas distribution customers and 12,000 propane distribution customers to our existing Florida operations. It also introduced us to the electric distribution business as we incorporated FPU s approximately 31,000 electric customers in northwest and northeast Florida.

In consummating the merger, we issued 2,487,910 shares of Chesapeake common stock at a price per share of $30.42 in exchange for all outstanding common stock of FPU. We also paid approximately $16,000 in lieu of issuing fractional shares in the exchange. There is no contingent consideration in the merger. Total value of considerations transferred by Chesapeake in the merger was approximately $75.7 million.

The assets acquired and liabilities assumed in the merger were recorded at their respective fair values at the completion of the merger. For certain assets acquired and liabilities assumed, such as pension and post-retirement benefit obligations, income taxes and contingencies without readily determinable fair value, for which GAAP provides specific exception to the fair value recognition and measurement, we applied other specified GAAP or accounting treatment as appropriate.

Table of Contents

The following table summarizes an adjusted allocation of the purchase price to the assets acquired and liabilities assumed at the date of the merger. Estimates of deferred income taxes, recovery of certain regulatory assets, and certain accruals are subject to change, pending the finalization of income tax returns and availability of additional information about the facts and circumstances that existed as of the merger closing. We will complete the purchase price allocation as soon as practicable but no later than one year from the merger closing.

(In thousands)	October 28, 2009
Purchase price	$ 75,699
Current assets	26,761
Property, plant and equipment	138,998
Regulatory assets	19,584
Investments and other deferred charges	3,659
Intangible assets	4,019
Total assets acquired	193,021
Long term debt	47,812
Borrowings from line of credit	4,249
Other current liabilities	17,427
Other regulatory liabilities	19,414
Pension and post retirement obligations	14,276
Environmental liabilities	12,414
Deferred income taxes	20,371
Customer deposits and other liabilities	15,467
Total liabilities assumed	151,430
Net identifiable assets acquired	41,591
Goodwill	$ 34,108

During the first quarter of 2010, we adjusted the allocation of purchase price based on additional information available. The adjustments are related to certain accruals, regulatory assets and deferred tax assets. These adjustments also resulted in a change in fair value of propane property, plant and equipment. Goodwill from the merger increased to $34.1 million after incorporating these adjustments, compared to $33.4 million prior to the adjustments.

None of the $34.1 million in goodwill recorded in connection with the merger is deductible for tax purposes. All of the goodwill recorded in connection with the merger is related to the regulated energy segment. We believe the goodwill recognized is attributable primarily to the strength of FPU s regulated energy businesses and the synergies and opportunities in the combined company. The intangible assets acquired in connection with the merger are related to propane customer relationships ($3.5 million) and favorable propane contracts ($519,000). The intangible value assigned to FPU s existing propane customer relationships will be amortized over a 12-year period based on the expected duration of benefit arising from the relationships. The intangible value assigned to FPU s favorable propane contracts will be amortized over a period ranging from one to 14 months based on contractual terms.

Current assets of $26.8 million acquired during the merger include notes receivable of approximately $5.8 million, for which we received payment in March 2010, and accounts receivable of approximately $3.1 million, $6.0 million and $891,000 for FPU s natural gas, electric and propane distribution businesses, respectively.

Table of Contents

The financial position and results of operations and cash flows of FPU from the effective date of the merger are included in our consolidated financial statements. The revenue and net income from FPU for the three months ended March 31, 2010, included in our condensed consolidated statements of income, were $54.2 million and $4.5 million, respectively.

The following table shows the actual results of combined operations for the three months ended March 31, 2010 and pro forma results of combined operations for the three months ended March 31, 2009, as if the merger had been completed at January 1, 2009. Since the effects of the merger for the three months ended March 31, 2010 were already included in the actual results of our consolidated operations, there is no pro forma adjustment for the three months ended March 31, 2010.

For the Three Months Ended March 31, *(in thousands, except per share data)*	**2010**	2009
Operating Revenues	**$ 153,260**	$ 147,672
Operating Income	**25,398**	18,344
Net income	**13,974**	9,556
Earnings per share basic	**$ 1.48**	$ 1.03
Earnings per share diluted	**$ 1.47**	$ 1.01

Pro forma results are presented for informational purposes only, and are not necessarily indicative of what the actual results would have been had the acquisition actually occurred on January 1, 2009.

The acquisition method of accounting requires acquisition-related costs to be expensed in the period in which those costs are incurred, rather than including them as a component of consideration transferred. It also prohibits an accrual of certain restructuring costs at the time of the merger. As we intend to seek recovery in future rates in Florida of a certain portion of the purchase premium paid and merger-related costs incurred, we also considered the impact of ASC Topic 980, Regulated Operations, in determining the proper accounting treatment for the merger-related costs. As of March 31, 2010, we incurred approximately $3.0 million in costs to consummate the merger, including the cost associated with merger-related litigation, and integrating operations following the merger. This includes $40,000 incurred during the three months ended March 31, 2010. We deferred approximately $1.5 million of the total costs incurred as a regulatory asset at March 31, 2010, which represents our estimate, based on similar proceedings in Florida in the past, of the costs which we expect to be permitted to recover when we complete the appropriate rate proceedings.

Included in the $3.0 million merger-related costs incurred as of March 31, 2010 were approximately $28,000 of severance and other restructuring charges for our efforts to integrate the operations of the two companies. We expect to incur an additional $300,000 in severance and other restructuring costs related to that effort during the second quarter of 2010.

Virginia LP Gas

On February 4, 2010, Sharp Energy, Inc. (Sharp), our propane distribution subsidiary, purchased the operating assets of Virginia LP Gas, Inc., a regional propane distributor serving approximately 1,000 retail customers in Northampton and Accomack Counties in Virginia. The total consideration for the purchase was $600,000, of which $300,000 was paid at the closing and the remaining $300,000 will be paid over 60 months. Based on our preliminary valuation, we allocated $412,000 of the purchase price to property, plant and equipment and the remaining $188,000 to intangible assets. There was no goodwill recorded in connection with this acquisition. The intangible assets acquired include customer relationships ($85,000) and non-compete agreements ($103,000), which will both be amortized over a seven-year period. The revenue and net income from this acquisition that are included in our condensed consolidated statement of income for the three months ended March 31, 2010 were not material. The allocation of purchase price is preliminary and we will complete the purchase price allocation as soon as practicable but no later than one year from the purchase of the assets.

Table of Contents

3. Calculation of Earnings Per Share

For the Three Months Ended March 31,		**2010**		**2009**
(in thousands, except Shares and Per Share Data)				
Calculation of Basic Earnings Per Share:				
Net Income	**$**	**13,974**	$	8,593
Weighted average shares outstanding		**9,419,932**		6,832,675
Basic Earnings Per Share	**$**	**1.48**	$	1.26
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	**$**	**13,974**	$	8,593
Effect of 8.25% Convertible debentures		**19**		20
Adjusted numerator Diluted	**$**	**13,993**	$	8,613
Reconciliation of Denominator:				
Weighted shares outstanding Basic		**9,419,932**		6,832,675
Effect of dilutive securities:				
Share-based Compensation		**16,090**		14,246
8.25% Convertible debentures		**88,276**		96,208
Adjusted denominator Diluted		**9,524,298**		6,943,129
Diluted Earnings Per Share	**$**	**1.47**	$	1.24

4. Commitments and Contingencies

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 (ESNG), our natural gas transmission operation, is subject to regulation by the Federal Energy Regulatory Commission (FERC). Chesapeake s Florida natural gas distribution division and FPU s natural gas and electric operations continue to be subject to regulation by the Florida Public Service Commission (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 has also recommended

that the Delaware PSC require us to adhere to asymmetrical pricing principles by applying the maximum tariff rates regarding all future capacity releases by the Delaware division to PESCO, if any. Accordingly, if the Hearing Examiner s recommendation were approved without modification by the Delaware PSC and if the Delaware division temporarily released any capacity to PESCO, 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, even though the temporary releases were made at lower rates based on competitive bidding procedures required by the FERC s capacity release rules. We disagreed with the Hearing Examiner s recommendations and filed exceptions to those recommendations on February 18, 2010. 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. We expect the Delaware PSC to issue an order in May 2010 outlining its decisions at the March hearing. The Delaware PSC s decision with regard to future capacity releases to PESCO contemplates that the parties will reconvene in a separate docket to determine if a pricing methodology other than asymmetrical pricing principles should apply to future capacity release by the Delaware division to PESCO.

On September 4, 2009, our Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2009. On October 6, 2009, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2009, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The first evidentiary hearing in this matter is scheduled for May 19, 2010. The Delaware division anticipates a final decision by the Delaware PSC on this application late in the second quarter or early in the third quarter of 2010.

On December 17, 2009, our Delaware division filed an application with the Delaware PSC, requesting approval for an Individual Contract Rate for service to be rendered to a potential large industrial customer. The Delaware PSC granted approval of the Individual Contract Rate on February 18, 2010.

<u>Maryland.</u> On December 1, 2009, 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 our Maryland division during the 12 months ended September 30, 2009. No issues were raised at the hearing, and on December 9, 2009, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. On January 8, 2010, the Maryland PSC issued an Order substantially affirming the Hearing Examiner s decision in the matter.

<u>Florida.</u> On July 14, 2009, Chesapeake s Florida division filed with the Florida PSC its petition for a rate increase and request for interim rate relief. In the application, the Florida division sought approval of: (a) an interim rate increase of $417,555; (b) a permanent rate increase of $2,965,398, which represented an average base rate increase, excluding fuel costs, of approximately 25 percent for the Florida division s customers; (c) implementation or modification of certain surcharge mechanisms; (d) restructuring of certain rate classifications; and (e) deferral of certain costs and the purchase premium associated with the then pending merger with FPU. On August 18, 2009, the Florida PSC approved the full amount of the Florida division s interim rate request, subject to refund, applicable to all meters read on or after September 1, 2009. On December 15, 2009, the Florida PSC: (a) approved a $2,536,307 permanent rate increase (86 percent of the requested amount) applicable to all meters read on or after January 14, 2010; (b) determined that there is no refund required of the interim rate increase; and (c) ordered Chesapeake s Florida division and FPU s natural gas distribution operations to submit data no later than April 29, 2011 (which is 18 months after the merger) that details all known benefits, synergies and cost savings and cost increases that have resulted from the merger.

Also on December 15, 2009, the Florida PSC approved the settlement agreement for a final natural gas rate increase of $7,969,000 for FPU s natural gas distribution operation, which represents approximately 80 percent of the requested base rate increase of $9,917,690 filed by FPU in the fourth quarter of 2008. The Florida PSC had approved an annual interim rate increase of $984,054 on February 10, 2009 and approved the permanent rate increase of $8,496,230 in an order issued on May 5, 2009, with the new rates to be effective beginning on June 4,

2009. On June 17, 2009, however, the Office of Public Counsel entered a protest to the Florida PSC s order and its final natural gas rate increase ruling, which the protest required a full hearing to be held within eight months. Subsequent negotiations led to the settlement agreement between the Office of Public Counsel and FPU, which the Florida PSC approved on December 15, 2009. The rates authorized pursuant to the order approving the settlement agreement became effective on January 14, 2010. In February 2010, FPU refunded to its natural gas customers approximately $290,000, representing revenues in excess of the amount provided by the settlement agreement that had been billed to customers from June 2009 through January 14, 2010.

Table of Contents

On September 1, 2009, FPU s electric distribution operation filed its annual Fuel and Purchased Power Recovery Clause, which seeks final approval of its 2008 fuel-related revenues and expenses and new fuel rates for 2010. On January 4, 2010, the Florida PSC approved the proposed 2010 fuel rates, effective on or after January 1, 2010.

On September 11, 2009, Chesapeake s Florida division and FPU s natural gas distribution operation separately filed their respective annual Energy Conservation Cost Recovery Clauses, seeking final approval of their 2008 conservation-related revenues and expenses and new conservation surcharge rates for 2010. On November 2, 2009, the Florida PSC approved the proposed 2010 conservation surcharge rates for both the Florida division and FPU, effective for meters read on or after January 1, 2010.

Also on September 11, 2009, FPU s natural gas distribution operation filed its annual Purchased Gas Adjustment Clause, seeking final approval of its 2008 purchased gas-related revenues and expenses and new purchased gas adjustment cap rate for 2010. On November 4, 2009, the Florida PSC approved the proposed 2010 purchased gas adjustment cap, effective on or after January 1, 2010.

The City of Marianna Commissioners voted on July 7, 2009 to enter into a new 10-year franchise agreement with FPU, effective February 1, 2010. The agreement provides that new interruptible and time-of-use rates shall become available for certain customers prior to February 2011, or, at the option of the City, the franchise agreement could be voided nine months after that date. The new franchise agreement contains a provision that permits the City to purchase the Marianna portion of FPU s electric system. Should FPU fail to make available the new interruptible and time-of-use rates, and if the franchise agreement is then voided by the City and the City elects to purchase the Marianna portion of the distribution system, the agreement would require the City to pay FPU severance/reintegration costs, the fair market value for the system, and an initial investment in the infrastructure to operate this limited facility. If the City purchased the electric system, FPU would have a gain in the year of the disposition; but, ongoing financial results would be negatively impacted from the loss of the Marianna area from its electric operations.

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

Energylink Expansion Project: In 2006, ESNG 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 ESNG s existing facilities in Sussex County, Delaware. In April 2009, ESNG terminated this project based on inadequate market support 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.

Prior Notice Request: On November 25, 2009, ESNG filed a prior notice request, proposing to construct, own and operate new mainline facilities to deliver additional firm entitlements of 1,594 Mcfs per day of natural gas to Chesapeake s Delaware division. The FERC published the notice of this filing on December 7, 2009 and with no protest having been filed during the 60-day period following the notice, the proposed activity became effective on February 6, 2010. ESNG expects to realize an annualized margin of approximately $343,000 upon its completion of the facilities and implementation of the new service, which is expected in May 2010.

Mainline Extension Interconnect Project: On March 5, 2010, ESNG submitted an Application for Certificate of Public Convenience and Necessity to the FERC related to its mainline extension interconnect project that would tie into the new expansion project undertaken by Texas Eastern Transmission, LP (TETLP). ESNG s project involves building and operating the eight-mile mainline extension from Honey Brook, Pennsylvania to ESNG s existing facility in Parkesburg, Pennsylvania. The estimated capital costs associated with construction of the mainline extension by ESNG is approximately $19.4 million. FERC noticed the application on March 15, 2010 and the comment period ended on April 5, 2010. There were three protests to this application. ESNG filed an answer to the protests on April 28, 2010.

Table of Contents

On December 11, 2009, ESNG filed revised tariff sheets to reflect a new section 42, Consolidation of Service Agreements, to the General Terms and Conditions of its FERC Gas Tariff. Section 42 states that shippers may, at their option and subject to certain conditions, consolidate multiple service agreements under a rate schedule into a new service agreement(s) under that rate schedule. The tariff sheets were accepted by the FERC on January 7, 2010, as proposed and were made effective January 15, 2010. As this new section allows for consolidation of existing service agreements only, there will be no financial impact on ESNG.

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, 2010, we had recorded $468,000 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, 2010, we have recorded approximately $1.6 million in regulatory and other assets for future recovery of environmental costs from Chesapeake s customers through its approved rates. As of March 31, 2010, we had recorded approximately $11.9 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 is approved to recover its environmental costs up to $14.0 million from insurance and customers through rates. Approximately $7.5 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of March 31, 2010. We also had recorded approximately $6.5 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 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 continued product monitoring and recovery. We have requested and are awaiting a No Further Action determination from the MDE.

Through March 31, 2010, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies at this site and do not expect to incur any additional costs. We have recovered approximately $2.1 million through insurance proceeds or in rates and have $754,000 of the clean-up costs not yet recovered.

Table of Contents

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-sparge/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. The Fourteenth Semi-Annual RAP Implementation Status Report was submitted to the FDEP in January 2010. The groundwater sampling results through October 2009 show, in general, a reduction in contaminant concentrations, although the rate of reduction has declined recently. Modifications and upgrades to the BS/SVE treatment system were completed in October 2009. At present, we predict that remedial action objectives may be met for the area being treated by the BS/SVE treatment system in approximately three years.

The BS/SVE treatment system does not address impacted soils in the southwest corner of the site. We are currently completing additional soil and groundwater sampling at this location for the purpose of designing a remedy for this portion of the site. Following the completion of this field work, we will submit a soil excavation plan to the FDEP for its review and approval.

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, 2010, we have incurred and paid approximately $1.5 million for this site and estimate an additional cost of $468,000 in the future, which has been accrued. We have recovered through rates $1.1 million of the costs and continue to expect that the remaining $829,000, 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. The FDEP has not required any further work at the site as of this time. Our portion of the consulting/remediation costs which may be incurred at this site is projected to be $93,000.

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida. The MGP was also owned by Gulf Power Corporation (Gulf Power). Portions of the site are now owned by the City of Pensacola and the Florida Department of Transportation. In October 2009, the FDEP informed Gulf Power that FDEP would approve a conditional No Further Action determination for the site, which must include a requirement for institutional/engineering controls. The group, consisting of Gulf Power, City of Pensacola, Florida Department of Transportation and FPU, is proceeding with preparation of the necessary documentation to submit the No Further Action justification. Consulting/remediation costs are projected to be $13,000.

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/operator of the MGP. In late September 2006, the U.S. 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.

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, 2010, 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 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/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, 2010, FPU s remaining share of remediation expenses, including attorneys fees and costs, is estimated to be $36,000. 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 funded 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 a revised feasibility study, evaluating appropriate remedies for the site, to the FDEP. 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 demands for additional information. The total projected cost of this work is approximately $763,000.

The feasibility study evaluated a wide range of remedial alternatives based on criteria provided by applicable laws and regulations. Based on the likely acceptability of proven remedial technologies described in the feasibility study and implemented at similar sites, management believes that consulting and remediation costs to address the impacts now characterized at the West Palm Beach site will range from $7.4 million to $18.9 million. This range of costs covers such remedies as in situ solidification for deeper soil impacts, excavation of superficial soil impacts, installation of a barrier wall with a permeable biotreatment zone, monitored natural attenuation of dissolved impacts in groundwater, or some combination of these remedies.

Table of Contents

Negotiations between FPU and the FDEP on a final remedy for the site continue. Prior to the conclusion of those negotiations, we are unable to determine, to a reasonable degree of certainty, the full extent or cost of remedial action that may be required. As of March 31, 2010, and subject to the limitations described above, we estimate the remediation expenses, including attorneys fees and costs, will range from approximately $7.8 million to $19.4 million for this site.

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.

Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase 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.

PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements before the existing agreements expire in May 2010.

FPU s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU s agreement with JEA (formerly known as Jacksonville Electric Authority) requires FPU to comply with the following ratios based on the result of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75; and (b) fixed charge coverage greater than 1.5. If either of the ratios is not met by FPU, we have 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU s agreement with Gulf Power Company requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operation interest coverage (minimum of 2 to 1); and (b) total debt to total capital (maximum of 0.65 to 1). If FPU fails to meet the requirements, we have 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 agreement with Gulf Power Company could result in FPU having to provide an irrevocable letter of credit. FPU was in compliance with these requirements as of March 31, 2010.

Corporate Guarantees

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, 2010 was $24.2 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 $725,000, which expires on August 31, 2010. The letter of credit is provided as security to satisfy the deductibles under our various insurance policies. There have been no draws on this letter of credit as of March 31, 2010. We do not anticipate that this letter of credit will be drawn upon by the counterparty, and we expect that it will be renewed to the extent necessary in the future.

Table of Contents

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 dekatherms per day (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 (f) 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 present sources of natural gas supplies are received primarily from the Gulf of Mexico natural gas production region and transported through two interstate upstream pipelines, which interconnect with the ESNG pipeline. These new contracts will provide our Delaware and Maryland divisions with access to new supplies of natural gas, providing increased reliability and diversity. They will also provide our Delaware and Maryland divisions additional upstream transportation capacity, which is essential to meet their current customer demands and to plan for sustainable growth.

On March 17, 2010, our Delaware and Maryland divisions entered into a separate Precedent Agreement with our natural gas transmission subsidiary, ESNG, to extend ESNG s mainline by eight miles to interconnect with TETLP at Honey Brook, Pennsylvania. The estimated capital costs associated with construction of the mainline extension by ESNG is approximately $19.4 million, and the proposed rate for transmission service on this extension is ESNG s current tariff rate for service in that area.

ESNG and TETLP are proceeding with obtaining the necessary approvals, authorizations or exemptions for construction and operation of their respective projects, 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 ESNG.

As the final scope of TETLP s expansion facilities is not known at this time, the reservation rates for service under the firm transportation service contracts were not specified in the Precedent Agreement with TETLP. TETLP is required to provide our Delaware and Maryland divisions a good faith estimate of the reservation rate by no later than June 30, 2010.

Once the TETLP firm transportation service contracts commence, our Delaware and Maryland divisions will incur costs from those services based on the agreed reservation rate, 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 TETLP firm transportation service contracts will be included in the annual GSR filings for each of our respective divisions.

If the reservation rate provided by TETLP in June 2010 is higher than the range of rates included in the TETLP Precedent Agreement, and we determine that the higher rate causes the value of service to be uneconomic to us, the Precedent Agreement provides that the parties shall promptly meet and work in good faith to negotiate a mutually acceptable reservation rate. If, however, the parties are unable to agree upon a mutually acceptable reservation rate, either party may terminate the Precedent Agreement and the related firm transportation service contracts. In the unlikely event of such termination, we may be required to reimburse TETLP for our proportionate share (prorated based on our total commitment of 40,000 Dts/d and the project total of 190,000 Dts/d) of TETLP s pre-service costs incurred as of the date of the termination. We estimate that our proportionate share could be approximately $363,000 upon such termination.

After our Delaware and Maryland divisions execute the negotiated rate agreements with TETLP, we would only be required 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. We believe that the likelihood of our Delaware and Maryland divisions terminating the Precedent Agreement after executing the negotiated rate agreements and having to reimburse TETLP for our proportionate share of TETLP s pre-service costs is remote. If such termination were to occur, we estimate that our proportionate share of TETLP s pre-service costs could be approximately $4.7 million by December 31, 2010. 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.

Table of Contents

We provided a letter of credit for $363,000 under the Precedent Agreement with TETLP in April 2010 as required. The letter of credit is expected to increase quarterly as TETLP s pre-service costs increases. The 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.

Other

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

5. Segment Information

We use the management approach to identify operating segments, and we organize our business around differences in regulatory environment and/or products or services. 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.

As a result of the merger with FPU in October 2009, we changed our operating segments to better reflect how the chief operating decision maker reviews the various operations of our Company. Our three operating segments are now composed of the following:

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 ESNG.

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,	2010	2009
(in thousands)		
Operating Revenues, Unaffiliated Customers		
Regulated Energy	**$ 91,300**	$ 51,793
Unregulated Energy	**59,027**	49,392
Other	**2,933**	3,294
Total operating revenues, unaffiliated customers	**$ 153,260**	$ 104,479
Intersegment Revenues (1)		
Regulated Energy	**$ 326**	$ 388
Unregulated Energy	**242**	2
Other	**187**	183
Total intersegment revenues	**$ 755**	$ 573
Operating Income (Loss)		
Regulated Energy	**$ 17,516**	$ 9,497
Unregulated Energy	**7,760**	6,592
Other and eliminations	**122**	(123)
Total operating income	**25,398**	15,966
Other income, net of other expenses	**115**	33
Interest	**2,363**	1,642
Income taxes	**9,176**	5,764
Net income	**$ 13,974**	$ 8,593

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

(in thousands)	March 31, 2010	December 31, 2009
Identifiable Assets		
Regulated energy	**$ 482,955**	$ 480,903

Unregulated energy	**76,725**	101,437
Other	**37,264**	34,724
Total identifiable assets	**$ 596,944**	$ 617,064

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.

6. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three months ended March 31, 2010 and 2009 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,	**2010**	**2009**	**2010**	**2010**	**2009**	**2010**	**2009**	**2010**
(in thousands)								
Service Cost	**$**	$	**$**	**$**	$	**$**	$	**$ 28**
Interest Cost	**145**	140	**638**	**34**	32	**30**	27	**34**
Expected return on plan assets	**(106)**	(86)	**(619)**					
Amortization of prior service cost	**(1)**	(1)		**5**	3			
Amortization of net loss	**39**	68		**16**	15	**15**	40	
Net periodic cost	**$ 77**	$ 121	**$ 19**	**$ 55**	$ 50	**$ 45**	$ 67	**$ 62**

Table of Contents

We expect to record pension and postretirement benefit costs of approximately $1.0 million for 2010 of which $320,000 is attributable to FPU s pension and medical plans. In addition, we expect to contribute $450,000 and $1.6 million to the Chesapeake and FPU pension plans, respectively, in 2010, of which $377,000 has been contributed for the FPU pension plan during the three months ended March 31, 2010. 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, 2010, were $22,000; for the year 2010, such benefits paid are expected to be approximately $88,000. Cash benefits paid for the Chesapeake Postretirement Plan and the FPU Medical Plan, primarily for medical claims, for the three months ended March 31, 2010, totaled $17,000 and $20,000, respectively; for the year 2010, we have estimated that approximately $115,000 and $144,000, respectively, will be paid for such benefits.

On March 23, 2010, the Patient Protection and Affordable Care Act was signed into law. On March 30, 2010, a companion bill, the Health Care and Education Reconciliation Act of 2010, was also signed into law. Among other things, these new laws, when taken together, reduce the tax benefits available to an employer that receives the Medicare Part D subsidy. The deferred tax effects of the reduced deductibility of the postretirement prescription drug coverage must be recognized in the period these new laws were enacted. The FPU Medical Plan receives the Medicare Part D subsidy. We assessed the deferred tax effects on the reduced deductibility as a result of these new laws during the three months ended March 31, 2010 and determined that the deferred tax effects were not material to our financial results.

7. Investments

The investment balance at March 31, 2010 represents a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan and a Rabbi Trust related to a stay bonus agreement with a former executive. 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, 2010 and December 31, 2009, total investments had a fair value of $2.0 million.

8. 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 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, 2010 and 2009.

For the Three Months Ended March 31,	**2010**	2009
(in thousands)		
Directors Stock Compensation Plan	**$ 64**	$ 47
Performance Incentive Plan	**269**	194
Total compensation expense	**333**	241
Less: tax benefit	**134**	97
Share-Based Compensation amounts included in net income	**$ 199**	$ 144

<u>Directors Stock Compensation Plan</u>

Shares granted under the DSCP are issued in advance of the directors service periods and are fully vested as of the date of the grant. We record a prepaid expense of the shares issued and amortize the expense equally over a service period of one year. No additional shares were granted under the DSCP during the three months ended March 31, 2010.

Table of Contents

Performance Incentive Plan

The table below presents the summary of the stock activity for the PIP for the three months ended March 31, 2010:

		Number of Shares		Weighted Average Fair Value
Outstanding	December 31, 2009	123,075	$	28.15
Granted		40,875	$	28.83
Vested		43,960		27.94
Fortfeited				
Expired		18,840		27.94
Outstanding	March 31, 2010	101,150	$	28.56

In January 2010, the Board of Directors granted awards under the PIP for 40,875 shares. The shares granted in January 2010 are multi-year awards, 8,000 shares of which will vest at the end of the two-year service period, or December 31, 2011. The remaining 32,875 shares will vest at the end of the three-year service period, or December 31, 2012. These awards are based upon the achievement of long-term goals, development and our success, and they comprise both market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Monte-Carlo pricing model to estimate the fair value of each market-based award granted.

At March 31, 2010, the aggregate intrinsic value of the PIP awards was $1.5 million.

9. 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, 2010, 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, net of future servicing costs, 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, 2010, we had the following outstanding trading contracts which we accounted for as derivatives:

At March 31, 2010	**Quantity in gallons**	**Estimated Market Prices**		**Weighted Average Contract Prices**	
Forward Contracts					
Sale	9,870,000	$ 1.0900	$1.19250	$	1.1235
Purchase	10,374,000	$ 1.0675	$1.19093	$	1.1169

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

All contracts expire within the second quarter of 2010.

- 21 -

Table of Contents

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, 2010 and December 31, 2009, are the following:

	Asset Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**March 31, 2010**	**December 31, 2009**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	**$ 198**	$ 2,379
Put option [1]	Mark-to-market energy assets		
Total asset derivatives		**$ 198**	$ 2,379

	Liability Derivatives		
		Fair Value	
(in thousands)	**Balance Sheet Location**	**March 31, 2010**	**December 31, 2009**
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	**$ 118**	$ 2,514
Total liability derivatives		**$ 118**	$ 2,514

(1) We purchased a put option for the Pro-Cap (propane price cap) plan in September 2009. The put option expired on March 31, 2010. The put option had a fair value of $0 at December 31, 2009.

The effects of gains and losses from derivative instruments on the condensed consolidated statements of income for the three months ended March 31, 2010 and 2009, are the following:

	Amount of Gain (Loss) on Derivatives:
	For the Three Months Ended
Location of Gain	**March 31,**

(in thousands)	**(Loss) on Derivatives**	**2010**	**2009**
Derivatives designated as fair value hedges			
Propane swap agreement [1]	Cost of Sales	**$**	$ (42)
Derivatives not designated as fair value hedges			
Unrealized gains (losses) on forward contracts	Revenue	**215**	(1,294)
Total		**$ 215**	$ (1,336)

[1] Our propane distribution operation entered into a propane swap agreement to protect it from the impact that wholesale propane price increases would have on the Pro-Cap (propane price cap) Plan that was offered to customers. We terminated this swap agreement in January 2009.

The effects of trading activities on the condensed consolidated statements of income for the three months ended March 31, 2010 and 2009, are the following:

(in thousands)	Location in the Statement of Income	Amount of Trading Revenue: For the Three Months Ended March 31, 2010	2009
Realized gains on forward contracts	Revenue	**$ 677**	$ 1,782
Unrealized gains (losses) on forward contracts	Revenue	**215**	(1,294)
Total		**$ 892**	$ 488

10. 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, 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	$ 2,040	$ 2,040	$	$
Mark-to-market energy assets	$ 198	$	$ 198	$
Liabilities:				
Mark-to-market energy liabilities	$ 118	$	$ 118	$

Table of Contents

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, 2009:

		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	$ 1,959	$ 1,959	$	$
Mark-to-market energy assets, including put option	$ 2,379	$	$ 2,379	$
Liabilities:				
Mark-to-market energy liabilities	$ 2,514	$	$ 2,514	$

The following valuation techniques were used to measure fair value assets in the table above on a recurring basis as of March 31, 2010 and December 31, 2009:

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 OTC markets.

Propane put option The fair value of the propane put option is valued using market transactions for similar assets and liabilities in either the listed or OTC markets.

At March 31, 2010, 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, 2010, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $107.1 million, compared to a fair value of $119.6 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, 2009, long-term debt, including the current maturities, had a carrying value of $134.1 million, compared to the estimated fair value of $145.5 million.

Table of Contents

11. Long Term Debt

Our outstanding long-term debt is shown below:

(in thousands)		**March 31, 2010**		**December 31, 2009**
Secured first mortgage bonds:				
9.57% bond, due May 1, 2018	**$**	**8,156**	$	8,156
10.03% bond, due May 1, 2018		**4,486**		4,486
9.08% bond, due June 1, 2022		**7,950**		7,950
6.85% bond, due October 1, 2031				14,012
4.90% bond, due November 1, 2031				13,222
Uncollateralized senior notes:				
6.91% note, due October 1, 2010		**909**		909
6.85% note, due January 1, 2012		**2,000**		2,000
7.83% note, due January 1, 2015		**10,000**		10,000
6.64% note, due October 31, 2017		**21,818**		21,818
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		**1,484**		1,520
Promissory notes		**310**		40
Total long-term debt		**107,113**		134,113
Less: current maturities		**(8,125)**		(35,299)
Total long-term debt, net of current maturities	**$**	**98,988**	$	98,814

In January 2010, we redeemed the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturity for $29.1 million, which included the outstanding principal balances, interest accrued, premium and fees. We used short-term borrowing to finance the redemption of these bonds. The difference between the carrying value of those bonds and the amount paid at redemption, totaling $1.5 million, was deferred as a regulatory asset as allowed by the Florida PSC.

We initially used our existing short-term borrowing facilities to finance the redemption of those bonds. On March 16, 2010, we entered into a new $29.1 million term loan credit facility with an existing lender to continue to finance the redemption. We borrowed $29.1 million for a nine-month period under this new facility, which bears interest at 1.88 percent per annum. We are currently in discussions with an existing noteholder for the long-term financing of the redeemed bonds.

Table of Contents

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, 2009, 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;

- 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
- operating and litigation risks that may not be covered by insurance.

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.

In addition, certain information is presented, which, for comparison purposes, includes only FPU s results of operations or excludes FPU s results from the consolidated results of operations for the first quarter of 2010. Although non-GAAP measures are not intended to replace the GAAP measures for evaluation of our performance, we believe that the portions of the presentation, which include only the FPU results, or which excludes FPU s financial results for the post-merger period, provide helpful comparisons for an investor s evaluation purposes.

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 through expansion 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 energy is highest due to colder temperatures.

Table of Contents

As a result of the merger with FPU in October 2009, we changed our operating segments to better reflect how the chief operating decision maker (our Chief Executive Officer) reviews the various operations of the Company. Our three operating segments are now composed of the following:

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 ESNG.

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.

We revised the segment information for the quarter ended March 31, 2009 to reflect the new operating segments.

Overview and Highlights

Our net income for the quarter ended March 31, 2010 was $14.0 million, or $1.47 per share (diluted). This represents an increase of $5.4 million, compared to a net income of $8.6 million, or $1.24 per share (diluted), reported in the same period in 2009.

For the Three Months Ended March 31,	**2010**	**2009**	**Change**
(in thousands)			
Operating Income (Loss):			
Regulated Energy	**$ 17,516**	$ 9,497	$ 8,019
Unregulated Energy	**7,760**	6,592	1,168
Other & eliminations	**122**	(123)	245
Operating Income	**25,398**	15,966	9,432
Other Income, net of expenses	**115**	33	82
Interest Charges	**2,363**	1,642	721
Income Taxes	**9,176**	5,764	3,412
Net Income	**$ 13,974**	$ 8,593	$ 5,381

The increased period-over-period operating results reflect an increase of $21.1 million in gross margin and an increase of $11.7 million in other operating expenses.

<u>*FPU Results*</u>

Our results for the first quarter of 2010 included approximately $4.5 million in net income contributed by FPU. Pursuant to the acquisition method of accounting, we consolidated FPU s results into our results from October 28, 2009, which is the effective date of the merger. Therefore, our results for the first quarter of 2009 did not include any results from FPU. The following is a summary of FPU s results for the quarter ended March 31, 2010 included in our consolidated results.

For the Three Months Ended March 31, 2010		
(in thousands)		
Operating Income:		
Regulated Energy	$	6,690
Unregulated Energy		1,362
Operating Income		8,052
Other Income, net of expenses		59
Interest Charges		893
Income Taxes		2,756
Net Income	$	4,462
Heating degree-days (HDD):		
Actual		933
10-year average (normal)		564

FPU s operating results by business for the quarter ended March 31, 2010 are presented in the following table:

	Regulated Energy				Unregulated Energy			
For the Three Months Ended March 31, 2010		**Natural Gas**		**Electric**		**Propane**		**Other**
(in thousands)								
Revenue	$	23,163	$	24,255	$	6,228	$	581
Cost of fuel		11,332		19,628		2,991		339
Gross margin		11,831		4,627		3,237		242
Other operating expenses		6,389		3,379		2,018		99
Operating Income	$	5,442	$	1,248	$	1,219	$	143
Average number of residential customers		52,071		30,916		13,742		

FPU s results for the first quarter of 2010 were positively affected by the increased natural gas and propane sales driven primarily by the colder than normal temperatures in Florida compared to the prior year, the increased natural gas gross margin resulting from the settlement of the permanent rate increase proceeding and lower interest expense following the redemption of two outstanding bond series and refinancing at short-term rates after the merger. FPU s propane results for the first quarter of 2010 also include approximately $390,000 in gross margin generated from customers transferred from Chesapeake to FPU after the merger in an effort to integrate operations.

Other Key Factors

The following is a summary of other key factors affecting our businesses and their impacts on our results in the first quarter of 2010. More detailed discussion and analysis are provided in the following section as we discuss our results by segment.

Weather. Temperatures on the Delmarva Peninsula during the first quarter of 2010 were four-percent colder than the same period in 2009 and nine-percent colder than normal (10-year average). The colder weather on the Delmarva Peninsula generated approximately $300,000 in additional gross margin in the first quarter of 2010 compared to the same period in 2009. The colder weather throughout Florida in the first quarter of 2010 also positively affected gross margins from the Florida operations.

Table of Contents

Growth. Our Delmarva natural gas distribution operation experienced two-percent residential customer growth in the first quarter of 2010. Including the increase in commercial and industrial customers, growth in our Delmarva natural gas distribution operation contributed approximately $443,000 in period-over-period additional gross margin. New transmission services and new expansion facilities placed in service during 2009 by our natural gas transmission subsidiary, ESNG, contributed an additional gross margin of $323,000 in the first quarter of 2010 compared to the same period in 2009. Chesapeake s Florida natural gas distribution division experienced a period-over-period net customer loss, primarily from the loss of several large industrial customers in 2009 due to economic conditions in the region, which decreased gross margin by $34,000.

Rates and Regulatory Matters. In December 2009, the Florida PSC approved a permanent rate increase of approximately $2.5 million, applicable to all meters read on or after January 14, 2010, for Chesapeake s Florida natural gas distribution division. The rate increase contributed an additional gross margin of $600,000 in the first quarter of 2010 compared to the same period in 2009.

Propane Prices. During the first half of 2009, our Delmarva propane distribution operation benefited from increased margin generated from the lower propane costs, largely attributable to inventory valuation adjustments in late 2008. The average propane cost in the first quarter of 2010 was 28 percent higher than the average propane cost in the same period in 2009, which decreased gross margin by $614,000. Increased volatility in wholesale propane prices provided opportunities for our propane wholesale marketing subsidiary, Xeron, as its trading volume increased by 12 percent in the first quarter of 2010 compared to the same period in 2009, increasing its gross margin by $405,000.

Natural Gas Spot Sale Opportunities. During the first quarter of 2009, our unregulated natural gas marketing subsidiary, PESCO, benefited from increased spot sales on the Delmarva Peninsula. Although PESCO continued to identify spot sale opportunities on the Delmarva Peninsula during the first quarter of 2010, the decreased spot sales, largely due to reduced sales to one industrial customer, resulted in a decrease in gross margin of $599,000 in the first quarter of 2010 compared to the same period in 2009. Spot sales are not predictable, and, therefore, are not included in our long-term financial plans or forecasts.

Other Operating Expenses. Our other operating expenses, excluding expenses reported by FPU, decreased by $175,000 in the first quarter of 2010 compared to the same period in 2009. Lower expenses related to collection and allowance for doubtful accounts receivable and cost containment measures implemented throughout 2009 for the advanced information services operation more than fully offset the increases in other operating expenses related to increased compensation and increased costs associated with increased capital investments.

Table of Contents

Regulated Energy

For the Three Months Ended March 31,	**2010**	**2009**	**Change**
(in thousands)			
Revenue	**$ 91,626**	$ 52,181	$ 39,445
Cost of sales	**53,768**	32,513	21,255
Gross margin	**37,858**	19,668	18,190
Operations & maintenance	**13,531**	6,951	6,580
Depreciation & amortization	**4,504**	1,792	2,712
Other taxes	**2,307**	1,428	879
Other operating expenses	**20,342**	10,171	10,171
Operating Income	**$ 17,516**	$ 9,497	$ 8,019
Statistical Data Delmarva Peninsula			
Heating degree-days (HDD[1]):			
Actual	**2,543**	2,453	90
10-year average (normal)	**2,336**	2,306	30
Estimated gross margin per HDD	**$ 2,429**	$ 1,937	$ 492
Per residential customer added:			
Estimated gross margin	**$ 375**	$ 375	$
Estimated other operating expenses	**$ 105**	$ 103	$ 2
Residential Customer Information			
Average number of customers [1]:			
Delmarva	**48,184**	47,379	805
Florida Chesapeake	**13,465**	13,473	(8)
Total	**61,649**	60,852	797

(1) Heating degree-days and average number of residential customers for FPU are included in the discussions of FPU s results on page 29.

Operating income for the regulated energy segment increased by approximately $8.0 million, or 84 percent, in the first quarter of 2010, compared to the same period in 2009, which was generated from a gross margin increase of $18.2 million, offset partially by an operating expense increase of $10.2 million.

Gross Margin

Gross margin for our regulated energy segment increased by $18.2 million, or 92 percent. FPU s natural gas and electric distribution operations had $11.8 million and $4.6 million in gross margin, respectively, in the first quarter of 2010, which contributed to this increase.

Table of Contents

The natural gas distribution operations for the Delmarva Peninsula generated an increase in gross margin of $401,000 in the first quarter of 2010. The factors contributing to this increase are as follows:

The Delmarva natural gas distribution operations experienced growth in residential, commercial and industrial customers, which contributed $443,000 to the gross margin increase. Residential, commercial and industrial growth by our Delaware division contributed $219,000, $76,000 and $51,000, respectively, to the gross margin increase, and commercial growth by our Maryland division contributed $104,000, to the gross margin increase. We experienced a two-percent increase in residential customers by the Delmarva natural gas distribution operation during the first quarter, and we expect that growth rate to continue in the near future.

Colder weather on the Delmarva Peninsula generated an additional $200,000 to the gross margin as heating degree-days increased by four percent over the previous first quarter. Residential heating rates for the 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.

Increases in gross margin were partially offset by a net decrease of $128,000 as a result of changes in customer rates and rate classes. Rates and rate classes for a commercial and an industrial customer in Maryland and certain residential customers in Delaware were revised in late 2009 and in the first quarter of 2010, based upon our review of their consumption, the prices of alternative fuels and a corresponding change in their rate, which led to this decrease.

In addition, a decrease of $101,000 in gross margin was attributable to the decline in non-weather related customer consumption. The decrease in consumption is a result of conservation primarily by residential customers.

Chesapeake s Florida natural gas distribution operation, excluding FPU, experienced an increase in gross margin of $892,000 in the first quarter of 2010. Approximately $600,000 of this increase was attributable to a permanent rate increase approved on December 15, 2009 (applicable to all meters read on or after January 14, 2010) by the Florida PSC. The increase was also attributable to increased customer consumption, which was heavily affected by the colder weather in Florida in the first quarter of 2010 and contributed $245,000 to the gross margin during the period. A decrease of $34,000 in gross margin due primarily to a loss of several large industrial customers in 2009 due to economic conditions in the region, was almost fully offset by an increase in gross margin of $33,000 attributable to increased consumption by existing industrial customers. Also gross margin increased by $41,000 as a result of changes in rates for certain customers.

The natural gas transmission operations achieved gross margin growth of $439,000 in the first quarter of 2010. The factors contributing to this increase are as follows:

New long-term transmission services implemented by ESNG in November 2009 as a result of the completion of its latest expansion program provided for an additional 6,957 Mcfs per day and added $254,000 to gross margin in the first quarter of 2010.

New long-term firm transmission service agreements with an industrial customer for the period from November 2009 to October 2012 provided for an additional 9,662 Mcfs per day for the period January 1, 2010 through February 5, 2010, and an additional 2,705 Mcfs per day for the period February 6, 2010 through March 31, 2010. They added $153,000 to gross margin in the first quarter of 2010.

In April 2009, ESNG changed its rates to recover specific project costs in accordance with the terms of precedent agreements with certain customers. These new rates generated $127,000 in gross margin in the first quarter of 2010. ESNG is currently in discussions with those customers to potentially reduce the period over which ESNG will recover its specific project costs in accordance with the terms of the precedent agreements.

ESNG received notice from a customer of its intention not to renew two firm transmission service contracts, which expired in October 2009 and March 2010, respectively, which decreased its gross margin by $84,000 in the first quarter of 2010.

Table of Contents

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $10.2 million, or 100 percent, in the first quarter of 2010 compared to the same period in 2009, of which $9.8 million was related to other operating expenses of FPU s regulated energy segment during the period. The remaining increase in other operating expenses is due primarily to the following factors:

Deprecation, asset removal costs and property taxes increased by $244,000 as a result of our increased capital investments made in 2009 and 2010 to support growth.

Payroll and benefits increased by $166,000 due primarily to annual salary increases and increased incentive pay as a result of improved performance.

Consulting expenses related to various regulatory proceedings involving our natural gas distribution operations increased by $107,000 during the quarter.

Other Developments

The following developments, which are not discussed above, may affect the future operating results of the regulated energy segment:

On March 15, 2010, we announced the signing of an agreement with an industrial customer to provide natural gas service to its poultry plant in southern Delaware. The anticipated annual margin from this agreement equates to approximately 850 average residential heating customers. The service is expected to begin in early 2011. This also provides us with an opportunity to extend our natural gas distribution and transmission infrastructures to serve other potential customers in the same area.

On April 8, 2010, we entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in conjunction with its new expansion project. 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, currently projected to occur in November 2012. 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. As a result of this new service, our Delaware and Maryland divisions will have access to new supplies of natural gas, providing increased reliability and diversity. This will also provide them additional upstream transportation capacity, which is essential to meet their current customer demands and to plan for sustainable growth. The Precedent Agreement with TETLP is fully described in Note 4, Commitments and Contingencies, to these unaudited condensed consolidated financial statements.

Unregulated Energy

For the Three Months Ended March 31,	**2010**	**2009**	**Change**
(in thousands)			
Revenue	**$ 59,269**	$ 49,394	$ 9,875
Cost of sales	**43,958**	37,088	6,870
Gross margin	**15,311**	12,306	3,005
Operations & maintenance	**6,026**	4,905	1,121
Depreciation & amortization	**1,046**	514	532
Other taxes	**479**	295	184
Other operating expenses	**7,551**	5,714	1,837
Operating Income	**$ 7,760**	$ 6,592	$ 1,168

Statistical Data Delmarva Peninsula						
Heating degree-days (HDD):						
Actual		**2,543**		2,453		90
10-year average (normal)		**2,336**		2,306		30
Estimated gross margin per HDD	**$**	**3,083**	$	2,465	$	618

Operating income for the unregulated energy segment increased by approximately $1.2 million, or 18 percent, in the first quarter of 2010 compared to the same period in 2009, which was attributable to a gross margin increase of $3.0 million, offset partially by an operating expense increase of $1.8 million.

Gross Margin

Gross margin for our unregulated energy segment increased by $3.0 million, or 24 percent, in the first quarter of 2010, compared to the same period in 2009. FPU s unregulated energy operation, which is primarily its propane distribution operation, contributed $3.1 million, net of approximately $390,000 generated from customers previously served by Chesapeake, as certain Chesapeake propane customers are now served by FPU after the merger in an effort to integrate operations.

Chesapeake s propane distribution operation, excluding FPU, now consists primarily of our Delmarva propane distribution operation. This operation experienced an increase in gross margin of $111,000, net of the $390,000 generated from customers previously served by Chesapeake who are now served by FPU. The factors contributing to this change are as follows:

Temperatures on the Delmarva Peninsula were four-percent colder in the first quarter of 2010, compared to the same period in 2009, which generated an additional $100,000 of gross margin.

Non-weather related volumes sold in the first quarter of 2010 increased by 1.1 million gallons, or eight percent, and provided for an increase in gross margin of approximately $497,000. The increase in non-weather related volumes was related to the addition of 390 community gas system customers and 1,000 additional retail customers acquired in February 2010 as part of the purchase of the operating assets of a regional propane distributor serving the Northampton and Accomack Counties in Virginia areas, which contributed $131,000 and $92,000 in gross margins during the quarter, respectively. Also contributing to the increase was $274,000 in additional gross margins related to the timing of propane deliveries to certain customers.

Other fees contributed $127,000 due primarily to the continued growth and successful implementation of various customer loyalty programs.

Partially offsetting the increases described above was a decline in propane margin per gallon. During the first quarter, our propane distribution operations experienced a decreased margin generated by higher propane costs, which were 28-percent higher than the average propane cost in the same period of 2009. This increase in the propane cost per gallon decreased margin by $614,000 during the first quarter.

Xeron, our propane wholesale marketing operation, experienced an increase in gross margin of $405,000 in the first quarter of 2010. Increased volatility in wholesale propane prices during the first quarter of 2010, compared to the same period in 2009, increased Xeron s trading opportunities as Xeron s trading volume increased by 12 percent. Also contributing to the increase were the significant wholesale propane price declines during the first quarter of 2009, which negatively affected Xeron s gross margin from trading activity in that period.

During the first quarter of 2009, our unregulated natural gas marketing subsidiary, PESCO, benefited from increased spot sales on the Delmarva Peninsula. Although PESCO continued to identify spot sale opportunities on the Delmarva Peninsula during the first quarter of 2010, the decreased spot sales, largely due to reduced sales to one industrial customer, resulted in a decrease in gross margin of $599,000 in the first quarter of 2010 compared to the same period in 2009. Spot sales are not predictable, and, therefore, are not included in our long-term financial plans or forecasts.

Other Operating Expenses

Total Other operating expenses for the unregulated energy segment increased by $1.8 million in 2010, of which $2.1 million was related to other operating expenses of FPU during the first quarter of 2010. Excluding FPU, total Other operating expenses decreased, due primarily to increased efforts to collect receivables for the natural gas marketing operations which resulted in a decrease in bad debt expense of $239,000.

Table of Contents

Other

For the Three Months Ended March 31,	2010	2009	Change
(in thousands)			
Revenue	**$ 2,365**	$ 2,904	$ (539)
Cost of sales	**1,133**	1,621	(488)
Gross margin	**1,232**	1,283	(51)
Operations & maintenance	**838**	1,004	(166)
Transaction-related costs	**19**	114	(95)
Depreciation & amortization	**73**	78	(5)
Other taxes	**180**	210	(30)
Other operating expenses	**1,110**	1,406	(296)
Operating Income (Loss)	**$ 122**	$ (123)	$ 245

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

Operating income for the Other segment increased by approximately $245,000 in the first quarter of 2010 compared to the same period in 2009.

Gross margin

The period-over-period decrease in gross margin for the Other segment was a result of a decrease in consulting revenues by the advanced information services operation due to a seven-percent decrease in the average consulting billing rate charged to customers, reflecting current economic conditions and information technology spending in the market. The number of billable consulting hours has remained unchanged. Despite the reduction in average consulting billing rate, the advanced information services operation was able to maintain its gross margin in the first quarter of 2010 compared to the same period in 2009 due to cost containment actions implemented in March, September and October 2009 and an increase in revenue and gross margin of $45,000 from its professional database monitoring and support solution services.

Operating expenses

Other operating expenses decreased by $296,000 in the first quarter of 2010. The decrease in operating expenses was attributable primarily to the cost containment actions, including layoffs and compensation adjustments, implemented by the advanced information services operation in March, September and October 2009 that reduced costs to offset the decline in revenues. In addition, we recorded lower merger-related costs in the first quarter of 2010.

Interest Expense

Our total interest expense for the first quarter of 2010 increased by approximately $721,000, or 44 percent, compared to the same period in 2009. The primary drivers of the increased interest expense are related to FPU, including:

An increase of long-term interest expense of $622,000 is related to interest on FPU s first mortgage bonds.

Two of the FPU series of bonds, 4.9 percent and 6.85 percent series, were redeemed by using a new short-term term loan facility at the end of January 2010. Interest expense from this short-term term loan facility during the first quarter of 2010 was $46,000.

Additional interest expense of $173,000 is related to interest on deposits from FPU s customers.

Offsetting the increased interest expense from FPU was lower long-term debt interest expense of $120,000 from Chesapeake s unsecured senior notes as the principal balances decreased from scheduled payments. Short-term interest expense remained relatively unchanged as a decrease in the average short-term borrowings of $6.8 million offset an increase in the average short-term interest rate of 35 basis points.

Income Taxes

We recorded an income tax expense of $9.2 million for the three months ended March 31, 2010, compared to $5.8 million for the three months ended March 31, 2009. The increase in income tax expense primarily reflects the higher earnings for the period. The effective income tax rate for the first quarter of 2010 is 39.6 percent compared to an effective tax rate of 40.2 percent for the first quarter of 2009. The decreased effective income tax rate resulted from a greater portion of our consolidated pre-tax income having been generated from entities in states with lower income tax rates, largely as a result of our expansion in Florida operations through the merger with FPU.

Financial Position, Liquidity and Capital Resources

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

During the first quarter of 2010, net cash provided by operating activities was $46.4 million, cash used in investing activities was $6.8 million, and cash used in financing activities was $32.3 million.

During the first quarter of 2009, net cash provided by operating activities was $31.0 million, cash used in investing activities was $4.1 million, and cash used in financing activities was $25.2 million.

As of March 31, 2010, we had four unsecured bank lines of credit with two financial institutions, for a total of $100.0 million, two of which totaling $60.0 million are available under committed lines of credit. None of the unsecured bank lines of credit requires compensating balances. These bank lines are available 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. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these short-term lines of credit. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. In addition to the four unsecured bank lines of credit, we entered into a new credit facility for $29.1 million with one of the financial institutions in March 2010. We borrowed $29.1 million under this new credit facility for a term of nine months to finance the early redemption of two series of FPU s secured first mortgage bonds. The outstanding balance of short-term borrowing at March 31, 2010 and December 31, 2009 was $29.1 and $30.0 million, respectively.

We have budgeted $53.9 million for capital expenditures during 2010. This amount includes $49.2 million for the regulated energy segment, $3.3 million for the unregulated energy segment and $1.4 million for the Other segment. The amount for the regulated energy segment includes estimated capital expenditures for the following: natural gas distribution operation ($20.2 million), natural gas transmission operation ($25.4 million) and electric distribution operation ($3.6 million) for expansion and improvement of facilities. 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 $288,000 for the advanced information services operation with the remaining balance for other general plant, computer software and hardware. We expect to fund the 2010 capital expenditures program from short-term borrowing, cash provided by operating activities, and other sources. The capital expenditure 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

The following presents our capitalization, excluding short-term borrowing, as of March 31, 2010 and December 31, 2009:

(in thousands)	March 31, 2010		December 31, 2009	
Long-term debt, net of current maturities	**$ 98,988**	**31%**	$ 98,814	32%
Stockholders equity	**221,181**	**69%**	209,781	68%
Total capitalization, excluding short-term debt	**$ 320,169**	**100%**	$ 308,595	100%

At March 31, 2010, common equity represented 69 percent of total capitalization, excluding short-term borrowing, compared to 68 percent at December 31, 2009. If short-term borrowing and the current portion of long-term debt were included in total capitalization, the equity component of our capitalization would have been 62 percent at March 31, 2010, compared to 56 percent at December 31, 2009.

We remain 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.

Cash Flows Provided By Operating Activities

Cash flows provided by operating activities were as follows:

For the Three Months Ended March 31,	**2010**	**2009**
(in thousands)		
Net Income	**$ 13,974**	$ 8,593
Non-cash adjustments to net income	**6,689**	4,299
Changes in assets and liabilities	**25,746**	18,144
Net cash provided by operating activities	**$ 46,409**	$ 31,036

During the three months ended March 31, 2010 and 2009, net cash flow provided by operating activities was $46.4 million and $31.0 million, respectively, a period-over-period increase of $15.4 million. FPU s operating activities in the first quarter of 2010 contributed $19.1 million to the period-over-period increase. The remaining net decrease in cash flow provided by operating activities was due primarily to the following:

Non-cash adjustment reflecting unrealized losses on commodity contracts decreased by approximately $1.5 million.

Net cash flows from the changes in regulatory liabilities decreased by approximately $3.9 million as we experienced lower over-collection of gas costs from rate-payers for Delmarva natural gas distribution operations.

Net cash flows from changes in inventory decreased by approximately $2.4 million due primarily to increased commodity costs.

Offsetting these decreases partially were: (a) increased net cash flows from customer deposits and refunds by approximately $2.3 million due to a new industrial customer for our Delmarva natural gas distribution operations requiring a large deposit and (b) higher net income by $920,000.

Cash Flows Used in Investing Activities

Net cash flows used in investing activities totaled $6.8 million and $4.1 million during the three months ended March 31, 2010 and 2009, respectively. Cash utilized for capital expenditures was $6.1 million and $4.1 million for the first three months of 2010 and 2009, respectively. Additions to property, plant and equipment in the first three months of 2010 include $2.3 million of FPU s capital expenditures. We also paid $310,000 of the $600,000 in total consideration for the purchase of certain propane assets from a regional propane distributor during the first quarter of 2010.

Cash Flows Used by Financing Activities

Cash flows used in financing activities totaled $32.3 million and $25.2 million for the first three months of 2010 and 2009, respectively. Significant financing activities reflected in the change in cash flows used by financing activities are as follows:

During the first three months of 2010, we repaid approximately $30.0 million of our short-term borrowings related to working capital, compared to net repayments of $23.2 million in the first three months of 2009, as we generated higher amounts of cash from operating activities.

In January 2010, we borrowed $29.1 million from our short-term credit facilities to redeem two series of FPU s secured first mortgage bonds prior to their respective maturities. We paid $28.9 million, including fees and penalties, related to the redemption.

We paid $2.7 million and $1.8 million in cash dividends for the three months ended March 31, 2010 and 2009, respectively. Dividends paid in the first quarter of 2010 increased as a result of growth in the annualized dividend rate and in the number of shares outstanding.

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 have 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, 2010 was $24.2 million, with the guarantees expiring on various dates in 2010.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $725,000, which expires on August 31, 2010. The letter of credit is provided as security to satisfy the deductibles under our various insurance policies. There have been no draws on this letter of credit as of March 31, 2010, and we do not anticipate that this letter of credit will be drawn upon by the counterparty in the future.

In April 2010, we provided a letter of credit for $363,000 under the Precedent Agreement with TETLP in April 2010 as required. The letter of credit is expected to increase quarterly as TETLP s pre-service costs increases. The 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.

Table of Contents

Contractual Obligations

There have not been any material changes in the contractual obligations presented in our 2009 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, 2010.

Purchase Obligations *(in thousands)*	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
Commodities [1] [3]	$ 40,894	$ 173	$	$	**$ 41,067**
Propane [2]	11,586				**11,586**
Total Purchase Obligations	$ 52,480	$ 173	$	$	**$ 52,653**

(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 $11.1 million. See Part I, Item 3, Quantitative and Qualitative Disclosures about Market Risk, below, for further information.

(3) In March 2009, we renewed our contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. There were no material changes to the contract s terms, as reported in our 2009 Annual Report on Form 10-K.

Environmental Matters

As more fully described in Note 4, 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; ESNG is subject to regulation by the FERC; and Peninsula Pipeline Company, Inc. (PIPECO) is subject to regulation by the Florida PSC. At March 31, 2010, we were involved in rate filings and/or regulatory matters in each of the jurisdictions in which we operate. Each of these rates or regulatory matters is fully described in Note 4, Commitments and Contingencies, to these unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Competition

Our natural gas and electric distribution operations and our natural gas transmission 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 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.

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

Inflation

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

Recent Authoritative Pronouncements on Financial Reporting and Accounting

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in the Recent Accounting Pronouncements section of 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 $107.1 million at March 31, 2010, as compared to a fair value of $119.6 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.

Table of Contents

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 four 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.

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, 2010 is presented in the following tables.

At March 31, 2010	**Quantity in gallons**	**Estimated Market Prices**		**Weighted Average Contract Prices**
Forward Contracts				
Sale	9,870,000	$ 1.0900	$1.19250	$ 1.1235
Purchase	10,374,000	$ 1.0675	$1.19093	$ 1.1169

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

All contracts expire within the second quarter of 2010.

At March 31, 2010 and December 31, 2009, 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, 2010**	**December 31, 2009**
Mark-to-market energy assets	**$ 198**	$ 2,379
Mark-to-market energy liabilities	**$ 118**	$ 2,514

Table of Contents

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, 2010. 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, 2010.

Changes in Internal Control Over Financial Reporting

During the quarter ended March 31, 2010, 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.

On October 28, 2009, the merger between Chesapeake and FPU was consummated. We are currently in the process of integrating FPU s operations and have not included FPU s activity in our evaluation of internal control over financial reporting. FPU s operations will be included in our assessment and report on internal control over financial reporting as of December 31, 2010.

Table of Contents

PART II OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 4, 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, 2009, should be carefully considered, together with the other information contained or incorporated by reference in the Quarterly Report on Form 10-Q including risks described below 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.

We may be required to reimburse TETLP for our proportionate share of its pre-service costs under the Precedent Agreement, which could be material to our financial position, results of operations and cash flows.

On April 8, 2010, we entered into a Precedent Agreement with TETLP to secure firm transportation service from TETLP in connection with its new expansion projects. As a result of this new transportation service, we would have access to new supplies of natural gas, providing increased reliability and diversity. The Precedent Agreement specifies certain events that would require us to reimburse TETLP for our proportionate share (prorated based on our total commitment of 40,000 Dts/d and the TETLP project total of 190,000 Dts/d) of TETLP s pre-service costs incurred as of such events. One such event would be the parties inability to agree within a specified time period upon a mutually acceptable negotiated reservation rate for the firm transportation service. Other such events include termination of the Precedent Agreement by us, our unwillingness or inability to perform our material duties and obligations as specified in the Precedent Agreement, or certain other actions by us that result in TETLP s inability to obtain the authorizations and exemptions required for this project. We believe that the likelihood of such events occurring that would require us to reimburse TETLP for our proportionate share of TETLP s pre-service costs pursuant to the Precedent Agreement is remote. If such unlikely events were to occur, we estimate that our proportionate share of TETLP s pre-service costs could be approximately $4.7 million by December 31, 2010. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, our proportionate share could be as much as approximately $45 million. The actual amount of our proportionate share could differ significantly and would ultimately be based on the level of pre-service costs only if and when that any such event occurs.

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, 2010 through January 31, 2010 [1]	279	$ 32.12		
February 1, 2010 through February 28, 2010		$		
March 1, 2010 through March 31, 2010		$		
Total	279	$ 32.12		

[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, 2010. During the quarter, 279 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.

Table of Contents

Item 6. Exhibits

3.1	Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective April 7, 2010, are incorporated herein by reference to Exhibit 3 of the Company s Current Report on Form 8-K, filed April 13, 2010, File No. 001-11590.
10.1	Term Note Agreement entered into by Chesapeake Utilities Corporation on March 16, 2010, pursuant to the $29.1 million credit facility with PNC Bank, N.A., is filed herewith.
10.2	Precedent Agreement between Chesapeake Utilities Corporation and Texas Eastern Transmission, LP, dated April 8, 2010, is filed herewith.[1]
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 7, 2010.
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 7, 2010.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 7, 2010.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated May 7, 2010.

[1]Portions of the Precedent Agreement have been omitted pursuant to a request for confidential treatment and have been filed separately with the SEC.

Table of Contents

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 7, 2010

- 46 -