

CHESAPEAKE UTILITIES CORP
Form 10-K
March 08, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended: December 31, 2012

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

State of Delaware
(State or other jurisdiction of

51-0064146
(I.R.S. Employer

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incorporation or organization)

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)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock par value per share \$0.4867	New York Stock Exchange, Inc.

Securities registered pursuant to Section 12(g) of the Act:

8.25% Convertible Debentures Due 2014

(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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 No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendments to this Form 10-K.

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 the definitions of "accelerated filer," "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer

Non-accelerated filer Smaller Reporting Company

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

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2012, the last business day of its most recently completed second fiscal quarter, based on the last trade price on that date, as reported by the New York Stock Exchange, was approximately \$401.3 million.

As of February 28, 2013 9,598,674 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2013 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III.

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GLOSSARY OF KEY TERMS AND DEFINITIONS

KEY TERMS

Acquisition adjustment: The recovery, through rates, and inclusion in rate base, of the premium (amount in excess of net book value) paid for an acquisition as approved by the state Public Service Commission for the regulated operations.

Allowed return: Return on equity or pre-tax, pre-interest rate of return on investment approved by the state Public Service Commission or the Federal Energy Regulatory Commission for the respective regulated operation.

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

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

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

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

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

Firm service: Regulated utility service that cannot be disrupted to meet the needs of other customers.

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

Fuel cost recovery mechanism: A regulatory method of adjusting the utility billing rates to reflect changes in the cost of purchased fuel for the natural gas and electric distribution operations. This allows matching of revenues with natural gas and electric supply and transportation costs and typically provides full recovery of such costs.

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

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

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

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

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

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

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

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

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

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

Rate Case: A periodic filing with the state Public Service Commission or the Federal Energy Regulatory Commission to establish equitable rates and balance the interests of all classes of customers and shareholders.

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

Transportation service: Natural gas service to customers whereby a customer purchases natural gas commodity directly from a supplier but pays the utility to transport the gas over its distribution or transmission system to the customer's facility.

DEFINITIONS

AFUDC: Allowance for funds used during construction

ASC: Accounting Standards Codification

ASU: Accounting Standards Update

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

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

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

Chesapeake Pension Plan: A defined benefit pension plan sponsored by Chesapeake

Chesapeake Postretirement Plan: An unfunded postretirement health care and life insurance plan sponsored by Chesapeake

Chesapeake SERP: An unfunded supplemental executive retirement pension plan sponsored by Chesapeake

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Columbia: Columbia Gas Transmission, LLC

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

Crescent: Crescent Propane, Inc.

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

Dodd-Frank Act: The Dodd-Frank Wall Street Reform and Consumer Protection Act

DSCP: Directors Stock Compensation Plan

Dt: Dekatherm, which is a natural gas unit of measurement that includes a standard measure for heating value

Dts/d: Dekatherms per day

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

EPA: United States Environmental Protection Agency

ESG: Eastern Shore Gas Company and its affiliates

FASB: Financial Accounting Standards Board

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

FDEP: Florida Department of Environmental Protection

FDOT: Florida Department of Transportation

FGT: Florida Gas Transmission Company

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

FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake

FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake

FRP: Fuel Retention Percentage

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

GRIP: Gas Reliability Infrastructure Program, which is a surcharge to natural gas customers designed to recover capital and other program-related costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services in Florida

GSR: Gas Service Rates

Gulf: Columbia Gulf Transmission Company

Gulf Power: Gulf Power Company

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Gulfstream: Gulfstream Natural Gas System, LLC

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

IFRS: International Financial Accounting Standards

IGC: Indiantown Gas Company

IRS: Internal Revenue Service

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

MDE: Maryland Department of Environment

Marianna Commission: The City Commission of Marianna, Florida

MWH: Megawatt hour, which is a unit of measurement for electricity

NAM: Natural Attenuation Monitoring

NRG: NRG Energy Center Dover LLC

NYSE: New York Stock Exchange

OTC: Over-the-counter

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

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

Peoples Gas: The Peoples Gas System division of Tampa Electric Company

PIP: Performance Incentive Plan

PSC: Public Service Commission, which is the state agency that regulates the rates and services provided by Chesapeake's natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida

Rayonier: Rayonier Performance Fibers, LLC

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

SEC: Securities and Exchange Commission

Sharp: Sharp Energy, Inc., a wholly-owned propane distribution subsidiary of Chesapeake.

S&P 500 Index: Standard & Poor's 500 Index

TETLP: Texas Eastern Transmission, LP

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TOU: Time-of-use

Transco: Transcontinental Gas Pipe Line Company, LLC

Virginia LP: Virginia LP Gas, Inc.

Xeron: Xeron, Inc., a wholly-owned propane wholesale marketing subsidiary of Chesapeake, based in Houston, Texas

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PART I

References in this document to Chesapeake, the Company, we, us and our mean Chesapeake Utilities Corporation, its divisions and/or its wholly-owned subsidiaries, as appropriate in the context of the disclosure.

Safe Harbor for Forward-Looking Statements

We make statements in this Annual Report on Form 10-K that do not directly or exclusively relate to historical facts. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as project, believe, expect, anticipate, intend, plan, estimate, potential, forecast or other similar words, or future or conditional verbs such as may, will, should, would or could. These statements reflect our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. These statements are subject to many risks and uncertainties. In addition to the risk factors described under Item 1A Risk Factors, the following important factors, among others, could cause actual future results to differ materially from those expressed in the forward-looking statements:

state and federal legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures, and affect the speed at and degree to which competition enters the electric and natural gas industries (including deregulation);

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

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

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

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

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

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

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

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

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

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

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

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

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

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

the ability to establish and maintain new key supply sources;

the effect of spot, forward and future market prices on our distribution, wholesale marketing and energy trading businesses;

the effect of competition on our businesses;

the ability to construct facilities at or below estimated costs; and

changes in technology affecting our advanced information services business.

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ITEM 1. BUSINESS.

(a) Overview

Chesapeake Utilities Corporation (Chesapeake or we) is a Delaware corporation that was formed in 1947. We are a diversified utility company engaged, through our operating divisions and subsidiaries, in various energy and other businesses. The core of our business is regulated energy, which provides stable earnings from utility operations on the Delmarva Peninsula and in Florida. Our unregulated energy and other businesses provide opportunities to achieve returns greater than those of a traditional utility. The following chart shows, in simplified form, our principal business structure:

On October 28, 2009, we completed a merger with Florida Public Utilities Company (FPU), pursuant to which FPU became a wholly-owned subsidiary of Chesapeake. The acquisition of FPU significantly increased our overall presence in Florida and expanded our energy diversity by adding electric distribution to our business. As a result of the FPU acquisition, Chesapeake is a utility holding company subject to the regulatory oversight of the Federal Energy Regulatory Commission (FERC).

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We are composed of three operating segments:

Regulated Energy. The regulated energy segment includes natural gas distribution, natural gas transmission and electric distribution operations. All operations in this segment are regulated, as to their rates and service, by the Public Service Commission (PSC) having jurisdiction in each state in which we operate or by the FERC in the case of Eastern Shore Natural Gas (Eastern Shore).

Unregulated Energy. The unregulated energy segment includes propane distribution, propane wholesale marketing and natural gas 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 shows the size of each of our operating segments based on operating income for 2012 and net property, plant and equipment as of December 31, 2012:

<i>(dollars in thousands)</i>	Operating Income		Net Property, Plant & Equipment	
Regulated Energy	\$ 46,999	83%	\$ 486,072	90%
Unregulated Energy	8,355	15%	38,582	7%
Other	1,281	2%	17,127	3%
Total	\$ 56,635	100%	\$ 541,781	100%

Additional financial information by business segment is included in Item 8 under the heading Notes to the Consolidated Financial Statements Note 5, Segment Information.

(i) Regulated EnergyOverview of Business

The regulated energy segment is our largest segment and consists of natural gas distribution and transmission operations on the Delmarva Peninsula and in Florida and an electric distribution operation in Florida.

Natural gas supplies nearly one-fourth of the energy used in the United States. Due to its efficiency, cleanliness and reliability, natural gas is growing increasingly popular. Supplies of natural gas are abundant, and 98.5 percent of the natural gas used in the United States comes from North America. Natural gas is delivered to customers through a safe and efficient underground pipeline system. As the cleanest-burning fossil fuel, increased use of natural gas can help address various environmental concerns today.

Table of Contents**Natural Gas Distribution**

Our Delmarva natural gas distribution operation serves 49,639 residential and 5,320 commercial and industrial customers in central and southern Delaware and on Maryland's eastern shore. For the year ended December 31, 2012, operating revenues and deliveries by customer class for our Delmarva natural gas distribution operation were as follows:

	Operating Revenues <i>(in thousands)</i>		Deliveries <i>(in Dts)</i>	
Residential	\$ 42,452	62%	2,511,444	28%
Commercial	19,250	29%	2,717,673	29%
Industrial	5,648	8%	3,876,693	42%
Subtotal	67,350	99%	9,105,810	99%
Interruptible	229	0%	124,063	1%
Other ⁽¹⁾	657	1%		
Total	\$ 68,236	100%	9,229,873	100%

⁽¹⁾ Operating revenues from Other include unbilled revenue, rental of gas properties, and other miscellaneous charges. Our Florida natural gas distribution operation consists of Chesapeake's Florida division, FPU's natural gas operation, which was acquired in October 2009, and FPU's Indiantown division, which was acquired in August 2010. Each component of our Florida natural gas distribution operation is separately regulated, as to its rates and service, by the Florida PSC. On a combined basis, our Florida natural gas distribution operation serves 62,386 residential customers and 6,670 commercial and industrial customers in 21 counties in Florida. For the year ended December 31, 2012, operating revenues and deliveries by customer class for our Florida natural gas distribution operation were as follows:

	Operating Revenues <i>(in thousands)</i>		Deliveries <i>(in Dts)</i>	
Residential	\$ 24,578	33%	1,532,234	7%
Commercial	31,331	42%	4,140,437	18%
Industrial	15,897	20%	17,611,441	74%
Other ⁽¹⁾	3,561	5%	181,566	1%
Total	\$ 75,367	100%	23,465,678	100%

⁽¹⁾ Operating revenues from Other include unbilled revenue, conservation revenue, fees for billing services provided to third parties, other miscellaneous charges and adjustments for pass-through taxes.

Natural Gas Transmission

Eastern Shore operates a 428-mile interstate pipeline system that transports natural gas from various points in Pennsylvania to our Delaware and Maryland natural gas distribution divisions, as well as to other utilities and industrial customers in southern Pennsylvania, Delaware and on the eastern shore of Maryland. Eastern Shore also provides swing transportation service and contract storage services. For the year ended December 31, 2012, operating revenues and deliveries by customer class for Eastern Shore were as follows:

Operating Revenues **Deliveries**

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	<i>(in thousands)</i>		<i>(in Dts)</i>	
Local distribution companies	\$ 22,365	66%	7,765,044	23%
Industrial	8,548	25%	23,337,949	68%
Commercial	2,947	9%	2,986,146	9%
Other ⁽¹⁾	46	0%		
Subtotal	33,906	100%	34,089,139	100%
Less: affiliated local distribution companies	(14,125)		(4,082,037)	
Total non-affiliated	\$ 19,781		30,007,102	

⁽¹⁾ Operating revenues from Other sources are from rental of gas properties and reserve for rate case refund. Peninsula Pipeline Company, Inc. (Peninsula Pipeline) provides natural gas transportation service to FPU's natural gas operation and an unaffiliated customer. Peninsula Pipeline transports natural gas to FPU in Nassau County, Florida, utilizing the 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida, which Peninsula Pipeline jointly owns with the Peoples Gas System division of Tampa Electric Company (Peoples Gas), as well as other pipelines solely owned by Peninsula Pipeline. Peninsula Pipeline commenced service to FPU in Nassau County, Florida in April 2012 and generated \$1.6 million in operating revenues for the year ended December 31, 2012.

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Peninsula Pipeline also provides natural gas transportation service to an unaffiliated customer under a 20-year agreement. This service, which began in January 2009, is provided at a fixed monthly charge through Peninsula Pipeline's eight-mile pipeline located in Suwanee County, Florida. For the year ended December 31, 2012, Peninsula Pipeline generated \$264,000 in operating revenues under the contract.

Electric Distribution

Our Florida electric distribution operation distributes electricity to 31,066 customers in four counties in northeast and northwest Florida. For the year ended December 31, 2012, operating revenues and deliveries by customer class for the FPU electric distribution operation were as follows:

	Operating Revenues <i>(in thousands)</i>		Deliveries <i>(in MWHs)</i>	
Residential	\$ 40,814	49%	292,980	44%
Commercial	38,079	46%	310,008	46%
Industrial	7,513	9%	58,640	9%
Subtotal	86,406	104%	661,628	99%
Other ⁽¹⁾	(3,845)	-4%	9,370	1%
Total	\$ 82,561	100%	670,998	100%

⁽¹⁾ Operating revenues from Other include unbilled revenue, conservation revenue, other miscellaneous charges and adjustments for pass-through taxes.

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Supplies, Transmission and Storage

We believe that the availability of supply and transmission of natural gas and electricity is adequate under existing arrangements to meet the anticipated needs of customers.

Natural Gas Distribution- Delmarva Peninsula

Our Delaware and Maryland natural gas distribution divisions have both firm and interruptible transportation service contracts with five interstate open access pipeline companies, including our Eastern Shore pipeline. These divisions are directly interconnected with the Eastern Shore pipeline, and have contracts with interstate pipelines upstream of Eastern Shore, including Transcontinental Gas Pipe Line Company LLC (Transco), Columbia Gas Transmission LLC (Columbia), Columbia Gulf Transmission Company (Gulf) and Texas Eastern Transmission, LP (TETLP). The Transco, Columbia and TETLP pipelines are directly interconnected with the Eastern Shore pipeline. The Gulf pipeline is directly interconnected with Columbia and indirectly interconnected with the Eastern Shore pipeline. None of the upstream pipelines is owned or operated by Chesapeake or any of its operating divisions and subsidiaries.

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP in conjunction with TETLP's new expansion project. On February 23, 2012, in accordance with the terms outlined in the Precedent Agreement, our Delaware and Maryland divisions entered into two separate firm transportation service agreements with TETLP for 30,000 Dekatherms per day (Dts/d) and 10,000 Dts/d, respectively, commencing in November 2012. In November 2013, the maximum daily quantity under these agreements increases to 34,100 Dts/d and 15,900 Dts/d for our Delaware and Maryland divisions, respectively. These new firm transportation service agreements provide us with an additional direct interconnection with Eastern Shore's transmission system and access to new sources of supply from other natural gas production regions, including the Appalachian production region, thereby providing increased reliability and diversity of supply. They also provide our Delaware and Maryland divisions with needed upstream transportation capacity to meet current and projected customer requirements.

The Delaware and Maryland divisions use their firm transportation resources to meet a significant percentage of their projected demand requirements. They purchase firm natural gas supplies to meet those projected requirements with purchases of baseload, daily spot and storage service. This gas is transported by the upstream pipelines and delivered to their interconnections with the Eastern Shore pipeline. The Delaware and Maryland divisions also have the capability to use propane-air peak-shaving equipment to supplement or displace natural gas purchases.

The following table shows the firm transportation and storage capacity for peak-day deliverability that the Delaware and Maryland divisions currently have under contract with Eastern Shore and pipelines upstream of the Eastern Shore pipeline, including the respective contract expiration dates.

Table of Contents*Delaware*

Pipeline	Firm transportation capacity maximum peak-day daily deliverability (in Dts)	Firm storage capacity maximum peak-day daily withdrawal (in Dts)	Expiration
Transco	21,423	6,230	Various dates between 2013 and 2028
Columbia	10,960	8,224	Various dates between 2014 and 2020
Gulf	880		Expires in 2014
TETLP	30,000		Expires in 2027
Eastern Shore	70,654	4,146	Various dates between 2013 and 2027

Maryland

Pipeline	Firm transportation capacity maximum peak-day daily deliverability (in Dts)	Firm storage capacity maximum peak-day daily withdrawal (in Dts)	Expiration
Transco	6,128	2,970	Various dates between 2013 and 2015
Columbia	4,200	3,663	Various dates between 2014 and 2019
Gulf	590		Expires in 2014
TETLP	10,000		Expires in 2027
Eastern Shore	27,398	2,307	Various dates between 2013 and 2027

Natural Gas Distribution - Florida

Chesapeake's Florida natural gas distribution division has firm transportation service contracts with Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System, LLC (Gulfstream). Pursuant to a program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties and Peninsula Energy Services Company, Inc. (PESCO), our natural gas marketing subsidiary. Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay for the service.

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Contracts by Chesapeake's Florida natural gas distribution division include two contracts with FGT, which expire on July 31, 2015 and 2020, and one contract with Gulfstream, which expires in 2022. These contracts are summarized in the following table:

Pipeline	Month(s)	Daily Firm Transportation Capacity	
		(in Dts)	Expiration
FGT	January to December	1,000	July 2015
FGT	November to April	17,639	July 2020
FGT	May to September	15,092	July 2020
FGT	October	16,579	July 2020
Gulfstream	January to December	10,000	May 2022

FPU has two firm transportation contracts with FGT, which expire in February 2015 and July 2020, respectively. FPU also has a third contract with FGT expiring in 2013, which contains reductions in the contracted transportation capacity between 2016 and 2023. FPU's firm transportation contract with Florida City Gas expires in 2013. In 2012, FPU entered into a 15-year firm transportation agreement with Peninsula Pipeline to provide natural gas service into Nassau and Okeechobee counties in Florida. These contracts are summarized in the following table:

Pipeline	Month(s)	Daily Firm Transportation Capacity	
		(in Dts)	Expiration
Florida City Gas	January to December	300	December 2013
FGT	January to April	10,564	February 2015
FGT	May to October	4,478	February 2015
FGT	November to December	10,564	February 2015
FGT	January to March	29,421	July 2020
FGT	April	24,808	July 2020
FGT	May to September	9,943	July 2020
FGT	October	10,485	July 2020
FGT	November to December	29,421	July 2020
FGT	January to December	1,822	Various dates between 2016 and 2023
Peninsula Pipeline	January to December	7,500	December 2027

FPU uses gas marketers and producers to procure all of its gas supplies for its natural gas distribution operation. FPU also uses Peoples Gas to provide wholesale gas sales service in areas distant from its interconnections with FGT.

Natural Gas Transmission

Eastern Shore has three contracts with Transco for a total of 7,292 dekatherms (Dts) of firm peak day storage entitlements and total storage capacity of 288,003 Dts. One of the contracts expires in 2013 and the other two expire in 2023. Eastern Shore is in the process of negotiating a 10-year extension of the contract which expires in 2013. Eastern Shore has retained these firm storage services in order to provide swing transportation service and firm storage service to customers that have requested such services.

Electric Distribution

Our electric distribution operation purchases its wholesale electricity primarily from two suppliers, JEA (formerly known as Jacksonville Electric Authority) and Gulf Power Company (Gulf Power), under all requirements contracts expiring in December 2017 and 2019, respectively. The JEA contract provides generation and transmission service to northeast Florida. The Gulf Power contract provides generation and transmission service to northwest Florida. Our electric distribution operation also has a renewable energy purchase agreement with Rayonier Performance Fibers, LLC (Rayonier). The Rayonier contract, which expires in 2023, commits FPU to purchase between 1.7 megawatt hour (MWH) and 3.0 MWH of electricity annually.

Table of Contents**Competition**

See discussion of competition in Item 7 under the heading Management's Discussion and Analysis of Financial Condition and Results of Operations - Competition.

Rates and Regulation

Our natural gas and electric distribution operations are subject to regulation by the Delaware, Maryland or Florida PSC with respect to various aspects of their business, including rates for sales and transportation to all customers in each respective regulatory jurisdiction. All of our firm distribution sales rates are subject to fuel cost recovery mechanisms, which match revenues with natural gas and electric supply and transportation costs and normally allow full recovery of such costs. Adjustments under these mechanisms, which are limited to such costs, require periodic filings and hearings with the state PSC having jurisdiction.

Eastern Shore is subject to regulation as an interstate pipeline by the FERC, which regulates the terms and conditions of service and the rates Eastern Shore can charge for its transportation and storage services. Peninsula Pipeline is subject to regulation by the Florida PSC.

The following table shows the regulatory jurisdictions under which our regulated energy businesses currently operate, including the effective dates of the most recent full rate proceedings and the rates of return that were authorized therein:

Regulated Business	Regulatory Jurisdiction	Effective Date of the Current Rates	Allowed Return
Chesapeake Delaware Division	Delaware PSC	9/3/2008	10.25% ⁽¹⁾
Chesapeake Maryland Division	Maryland PSC	12/1/2007	10.75% ⁽¹⁾
Chesapeake Florida Division	Florida PSC	1/14/2010	10.80% ⁽¹⁾
FPU Natural Gas	Florida PSC	1/14/2010 ⁽³⁾	10.85% ⁽¹⁾
FPU Indiantown Division	Florida PSC	6/17/2004	11.50% ⁽¹⁾
FPU Electric	Florida PSC	5/22/2008	11.00% ⁽¹⁾
Eastern Shore	FERC	7/29/2011	13.90% ⁽²⁾

⁽¹⁾ Allowed return on equity

⁽²⁾ Allowed overall pre-tax, pre-interest rate of return

⁽³⁾ Effective date of the order approving the settlement agreement, which adjusted rates originally approved on June 4, 2009. Peninsula Pipeline provides services based on negotiated rates, which are approved by the Florida PSC.

Management monitors the achieved rates of return of each of our regulated energy operations in order to ensure timely filing of rate cases.

Regulatory Proceedings

See discussion of regulatory activities in Item 8 under the heading Notes to the Consolidated Financial Statements - Note 17, Rates and Other Regulatory Activities.

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Seasonality of Natural Gas and Electric Distribution Revenues

Revenues from our residential and commercial natural gas distribution activities are affected by seasonal variations in weather conditions, which directly influence the volume of natural gas and electricity sold and delivered. Specifically, customer demand substantially increases during the winter months, when natural gas and electricity are used for heating. For electricity, customer demand also increases during the summer months, when electricity is used for cooling. Accordingly, the volumes sold for these purposes are directly affected by the severity of summer and winter weather and can vary substantially from year to year. Sustained warmer-than-normal temperatures during the heating season will tend to reduce use of natural gas and electricity, while sustained colder-than-normal temperatures will tend to increase consumption. Sustained cooler-than-normal temperatures during the cooling season will negatively affect electricity consumption. We measure the relative impact of weather by using an accepted degree-day methodology. Degree-day data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am) falls above or below 65 degrees Fahrenheit. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating degree-day. Each degree of temperature above 65 degree Fahrenheit is counted as one cooling degree-day. Normal heating degree-days are based on the most recent 10-year average.

For the electric distribution operations in northeast and northwest Florida, hot summers and cold winters produce year-round electric sales that normally do not have large seasonal fluctuations.

In an effort to stabilize the level of net revenues collected from customers in Maryland regardless of weather conditions, we implemented a weather normalization adjustment for our residential heating and smaller commercial heating customers. A weather normalization adjustment is a billing adjustment mechanism that is designed to eliminate the effect of deviations from average seasonal temperatures on utility net revenues.

Delaware, like many other states, has been looking at ways to enable implementation of energy efficiency and is considering revenue decoupling, which is a mechanism for separating the revenue needed to recover the fixed cost of delivery from the variable cost that fluctuates with the amount of natural gas consumed. Although the Delaware PSC has been investigating whether to implement a revenue decoupling mechanism for the natural gas distribution utilities in the state, it is uncertain as to whether the Delaware PSC will require our Delaware natural gas distribution division to file a request for decoupling or whether our Delaware division will file such request on its own.

(ii) Unregulated Energy

Overview of Business

Our unregulated energy segment provides propane distribution, propane wholesale marketing and natural gas marketing services to customers.

Propane Distribution

Propane is a form of liquefied petroleum gas, which is typically extracted from natural gas or separated during the crude oil refining process. Although propane is a gas at normal pressure, it is easily compressed into liquid form for storage and transportation. Propane is a clean-burning fuel, gaining increased recognition for its environmental superiority, safety, efficiency, transportability and ease of use relative to alternative forms of fossil fuels. Propane is sold primarily in suburban and rural areas which are not served by natural gas distributors.

Our propane distribution operations sell propane primarily to residential, commercial/industrial and wholesale customers. Approximately 77 percent of operating revenues in 2012 were generated by the sales to retail residential, commercial and industrial customers. Sharp Energy Inc. (Sharp), our propane distribution subsidiary, serves 34,837 customers throughout Delaware, the eastern shore of Maryland and Virginia, and southeastern Pennsylvania. Our Florida propane distribution subsidiaries provide propane distribution service to 14,475 customers in various counties in Florida. For the year ended December 31, 2012, operating revenues and total gallons sold by our Delmarva and Florida propane distribution operations were as follows:

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Service Area	Operating Revenues		Total Gallons Sold	
	<i>(in thousands)</i>		<i>(in thousands)</i>	
Delmarva	\$ 60,985	76%	31,441	84%
Florida	18,931	24%	5,997	16%
Total	\$ 79,916	100%	37,438	100%

Propane Wholesale Marketing

Xeron, Inc. (Xeron), our propane wholesale marketing subsidiary, markets propane to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States. Xeron enters into forward contracts with various counterparties to commit to purchase or sell an agreed-upon quantity of propane at an agreed-upon price at a specified future date, which typically ranges from one to six months from the execution of the contract. At the expiration of the forward contracts, Xeron typically settles its purchases and sales financially without taking the physical delivery of propane. Xeron also enters into futures and other option contracts that are traded on the InterContinentalExchange, Inc. The level and profitability of the propane wholesale marketing activity is affected by both propane wholesale price volatility and liquidity in the wholesale market. In 2012, Xeron had operating revenues totaling approximately \$2.5 million, net of the associated cost of propane sold. For further discussion of Xeron's wholesale marketing activities, market risks and controls that monitor Xeron's risks, see Item 7 under the heading Management's Discussion and Analysis of Financial Condition and Results of Operations Market Risk.

Xeron does not own physical storage facilities or equipment to transport propane; however, it contracts for storage and pipeline capacity to facilitate the sale of propane on a wholesale basis.

Natural Gas Marketing

Our natural gas marketing subsidiary, PESCO, provides natural gas supply and supply management services to 3,189 customers in Florida and 28 customers on the Delmarva Peninsula. It competes with regulated utilities and other unregulated third-party marketers to sell natural gas supplies directly to commercial and industrial customers through competitively-priced contracts. PESCO does not own or operate any natural gas transmission or distribution assets. The gas that PESCO sells is delivered to retail customers through affiliated and non-affiliated local distribution company systems and transmission pipelines. PESCO bills its customers through the billing services of the regulated utilities that deliver the gas, or directly, through its own billing capabilities. For the year ended December 31, 2012, PESCO's operating revenues and deliveries were as follows:

Service Area	Operating Revenues		Deliveries	
	<i>(in thousands)</i>		<i>(in Dts)</i>	
Florida	\$ 42,019	86%	14,766,667	91%
Delmarva	7,020	14%	1,544,849	9%
Subtotal	49,039	100%	16,311,516	100%
Less: sale to affiliate	(3,029)		(856,615)	
Total unaffiliated	\$ 46,010		15,454,901	

PESCO currently has contracts with natural gas production companies for the purchase of firm natural gas supplies. These contracts provide a maximum firm daily entitlement of 35,000 Dts and expire in May 2013. PESCO is currently in the process of obtaining and reviewing proposals from suppliers and anticipates executing agreements prior to the end of the term of the existing contracts.

Supplies, Transportation and Storage

Our propane distribution operations purchase propane primarily from suppliers, including major oil companies, independent producers of natural gas liquids and from Xeron. In current markets, supplies of propane from these and other sources are readily available for purchase.

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Our propane distribution operations use trucks and railroad cars to transport propane from refineries, natural gas processing plants or pipeline terminals to our bulk storage facilities. We own bulk propane storage facilities with an aggregate capacity of approximately 3.4 million gallons at various locations in Delaware, Maryland, Pennsylvania, Virginia and Florida. From these storage facilities, propane is delivered by bobtail trucks, owned and operated by us, to tanks located at the customers' premises.

Competition

See discussion of competition in Item 7 under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations - Competition."

Rates and Regulation

Propane distribution, propane wholesale marketing and natural gas marketing activities are not subject to any federal or state pricing regulation. Transport operations are subject to regulations concerning the transportation of hazardous materials promulgated by the Federal Motor Carrier Safety Administration within the United States Department of Transportation and enforced by the various states in which such operations take place. Propane distribution operations are also subject to state safety regulations relating to hook-up and placement of propane tanks.

Seasonality of Propane Revenues

Revenues from our propane distribution sales activities are affected by seasonal variations in weather conditions. Weather conditions directly influence the volume of propane sold and delivered to customers; specifically, customers' demand substantially increases during the winter months when propane is used for heating. Accordingly, the propane volumes sold for this purpose are directly affected by the severity of winter weather and can vary substantially from year to year. Sustained warmer-than-normal temperatures will tend to reduce propane use, while sustained colder-than-normal temperatures will tend to increase consumption.

Many of our propane distribution customers are bulk delivery customers. We make deliveries of propane to the bulk delivery customers as needed, based on the level of propane remaining in the tank located at the customer's premises. We invoice and record revenues for our bulk delivery service customers at the time of delivery, rather than upon customers' actual usage, since the customers own the propane gas in the tank on their premises. The timing of deliveries to the bulk delivery customers can vary significantly from year to year depending on weather variation.

(iii) Other

The Other segment consists primarily of our advanced information services subsidiary, other unregulated subsidiaries that own real estate leased to Chesapeake and its subsidiaries and certain unallocated corporate costs, which are not directly attributable to a specific business unit.

Advanced Information Services

Our advanced information services subsidiary, BravePoint[®], Inc. (BravePoint), is headquartered in Norcross, Georgia, and provides domestic and a limited number of international clients with information technology services and solutions for both enterprise and e-business applications.

Other Subsidiaries

Skipjack, Inc. and Eastern Shore Real Estate, Inc. own and lease office buildings in Delaware and Maryland to affiliates of Chesapeake. Chesapeake Investment Company is an affiliated investment company incorporated in Delaware.

(c) Additional Information about the Business

(i) Capital Budget

A discussion of capital expenditures by business segment and capital expenditures for environmental remediation facilities is included in Item 7 under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources."

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(ii) Employees

As of December 31, 2012, we had a total of 738 employees, 127 of whom are union employees represented by three labor unions: the International Brotherhood of Electrical Workers, the International Chemical Workers Union and United Food and Commercial Workers Union, all of whose collective bargaining agreements expire in 2013.

(iii) Financial Information about Geographic Areas

All of our material operations, customers and assets are located in the United States.

(d) Available Information

As a public company, we file annual, quarterly and other reports, as well as our annual proxy statement and other information, with the Securities and Exchange Commission (SEC). The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room, 100 F Street, N.E., Washington, DC 20549-5546; the public may obtain information from the Public Reference Room by calling the SEC at 1-800-SEC-0330.

The SEC also maintains an Internet site that contains reports, proxy and information statements and other information regarding the Company. The address of the SEC s Internet website is www.sec.gov. We make available, free of charge, on our Internet website, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after such reports are electronically filed with or furnished to the SEC. The address of our Internet website is www.chpk.com. The content of this website is not part of this report.

We have a Business Code of Ethics and Conduct applicable to all employees, officers and directors and a Code of Ethics for Financial Officers. Copies of the Business Code of Ethics and Conduct and the Code of Ethics for Financial Officers are available on our Internet website. We also adopted Corporate Governance Guidelines and Charters for the Audit Committee, Compensation Committee and Corporate Governance Committee of the Board of Directors, each of which satisfies the regulatory requirements established by the SEC and the New York Stock Exchange (NYSE). The Board of Directors has also adopted Corporate Governance Guidelines on Director Independence, which conform to the NYSE listing standards on director independence. These documents are available on our Internet website or may be obtained by writing to: Corporate Secretary; c/o Chesapeake Utilities Corporation, 909 Silver Lake Boulevard, Dover, DE 19904.

If we make any amendment to, or grant a waiver of, any provision of the Business Code of Ethics and Conduct or the Code of Ethics for Financial Officers applicable to our principal executive officer, president, principal financial officer, principal accounting officer or controller, the amendment or waiver will be disclosed within four business days in a press release, by website disclosure, or by filing a current report on Form 8-K with the SEC.

Our Chief Executive Officer certified to the NYSE on May 31, 2012, that as of that date, he was unaware of any violation by Chesapeake of the NYSE s corporate governance listing standards.

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ITEM 1A. RISK FACTORS.

The following is a discussion of the primary factors that may affect the operations or financial performance of our regulated and unregulated businesses. Refer to the section entitled Management's Discussion and Analysis of Financial Condition and Results of Operations under Item 7 of this report for an additional discussion of these and other related factors that affect our operations and/or financial performance.

Financial Risks

Instability and volatility in the financial markets could have a negative impact on our ability to access capital at competitive rates.

Our business strategy includes the continued pursuit of growth, both organically and through acquisitions. To the extent that we do not generate sufficient cash flow from operations, we may incur additional indebtedness to finance our growth. Specifically, we rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flows from our operations. We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access the capital markets when required. However, if we are not able to access capital at competitive rates, our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth may be limited.

A downgrade in our credit rating could adversely affect our access to capital markets and our cost of capital.

Our ability to obtain adequate and cost-effective capital depends on our credit ratings, which are greatly affected by our financial performance and the liquidity of financial markets. A downgrade in our current credit ratings could adversely affect our access to capital markets, as well as our cost of capital.

If we fail to comply with our debt covenant obligations, we could experience adverse financial consequences that could affect our liquidity and ability to borrow funds.

Our long-term debt obligations and committed short-term lines of credit contain financial covenants related to debt-to-capital ratios and interest-coverage ratios. Failure to comply with any of these covenants could result in an event of default which, if not cured or waived, could result in the acceleration of outstanding debt obligations or the inability to borrow under certain credit agreements. Any such acceleration would cause a material adverse change in our financial condition.

An increase in interest rates may adversely affect our results of operations and cash flows.

An increase in interest rates, without the recovery of the higher cost of debt in the sales and/or transportation rates we charge our utility customers, could adversely affect future earnings. An increase in short-term interest rates would negatively affect our results of operations, which depend on short-term lines of credit to finance accounts receivable and storage gas inventories, as well as to temporarily finance capital expenditures.

Inflation may impact our results of operations, cash flows and financial position.

Inflation affects the cost of supply, labor, products and services required for operations, maintenance and capital improvements. To help cope with the effects of inflation on our capital investments and returns, we seek rate increases from regulatory commissions for regulated operations and closely monitor the returns of our unregulated operations. There can be no assurance that we will be able to obtain adequate and timely rate increases to offset the effects of inflation. To compensate for fluctuations in propane gas prices, we adjust our propane selling prices to the extent allowed by the market. There can be no assurance, however, that we will be able to increase propane sales prices sufficiently to compensate fully for such fluctuations in the cost of propane gas to us.

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Our energy marketing subsidiaries are exposed to market risks, beyond our control, which could adversely affect our financial results and capital requirements.

Our energy marketing subsidiaries are subject to market risks beyond their control, including market liquidity and commodity price volatility. Although we maintain risk management policies, we may not be able to offset completely the price risk associated with volatile commodity prices, which could lead to volatility in earnings. Physical trading also has price risk on any net open positions at the end of each trading day, as well as volatility resulting from: (i) intra-day fluctuations of natural gas and/or propane prices, and (ii) daily price movements between the time natural gas and/or propane is purchased or sold for future delivery and the time the related purchase or sale is hedged. The determination of our net open position at the end of any trading day requires us to make assumptions as to future circumstances, including the use of natural gas and/or propane by its customers in relation to its anticipated market positions. Because the price risk associated with any net open position at the end of such day may increase if the assumptions are not realized, we review these assumptions daily. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner, because the timing of the recognition of profits or losses on the economic hedges for financial accounting purposes usually does not match up with the timing of the economic profits or losses on the item being hedged. This volatility may occur, with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated.

Our energy marketing subsidiaries are exposed to credit risk of their counterparties.

Our energy marketing subsidiaries extend credit to counterparties and continually monitor and manage collections aggressively. Each of these subsidiaries is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform, and any underlying collateral is inadequate, we could experience financial losses.

Our energy marketing subsidiaries are dependent upon the availability of credit to successfully operate their businesses.

Our energy marketing subsidiaries are dependent upon the availability of credit to buy propane and natural gas for resale or to trade. If financial market conditions decline generally, or the financial condition of these subsidiaries or of our Company declines, then the cost of credit available to these subsidiaries could increase. If credit is not available, or if credit is more costly, our results of operations, cash flows and financial condition may be adversely affected.

Current market conditions have adversely impacted the return on plan assets for our pension plans, which may require significant additional funding.

We have pension plans that have been closed to new employees. The costs of providing benefits and related funding requirements of these plans are subject to changes in the market value of the assets that fund the plans and the discount rates used to estimate the pension benefit obligations. As a result of the extreme volatility and disruption in the domestic and international equity, bond and interest rate markets in recent years, the asset values and benefit obligations of Chesapeake's and FPU's pension plans have fluctuated significantly since 2008. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors that are subject to an inherent degree of uncertainty, particularly in the current economic environment. Future losses of asset values and further declines in discount rates may necessitate accelerated funding of the plans in the future to meet minimum federal government requirements as well as higher pension expense to be recorded in future years. Adverse changes on the asset values and benefit obligations of our pension plans may require us to record higher pension expense and fund obligations earlier than originally planned, which would have an adverse impact on our cash flows from operations, decrease borrowing capacity and increase interest expense.

Operational Risks

Fluctuations in weather may cause a significant variance in our earnings.

Our natural gas and propane distribution operations are sensitive to fluctuations in weather conditions, which directly influence the volume of natural gas and propane we sell and deliver to our customers. A significant portion of our natural gas and propane distribution revenues is derived from the sales and deliveries of natural gas and propane to residential and commercial heating customers during the five-month peak heating season (November through March). If the weather is warmer than normal, we sell and deliver less natural gas and propane to customers, and earn less revenue, which could adversely affect our results of operations, cash flows and financial condition.

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Our electric operation, while generally less seasonal than natural gas and propane sales because electricity is used for both heating and cooling in our service areas, is also affected by variations in general weather conditions and particularly unusually severe weather conditions.

The amount and availability of natural gas, propane and electricity supplies are difficult to predict; a substantial reduction in available supplies could reduce our earnings in those segments.

Natural gas, propane and electricity production can be affected by factors beyond our control, such as weather, closings of energy generation facilities and refineries. If we are unable to obtain sufficient natural gas, electricity and propane supplies to meet demand, results in those businesses may be adversely affected. Any substantial decrease in the availability of supplies of natural gas, propane and electricity could result in increased supply costs and higher prices for customers, which could also adversely affect our financial condition and results of operations.

We rely on a limited number of natural gas, propane and electricity suppliers, the loss of which could have a material adverse effect on our financial condition and results of operations.

We have entered into various agreements with suppliers to purchase natural gas, propane and electricity to serve our customers. The loss of any significant suppliers or our inability to renew these contracts at favorable terms upon their expiration could significantly affect our ability to serve our customers and have a material adverse impact on our financial condition and results of operations.

A substantial disruption or lack of growth in interstate natural gas pipelines transmission and storage capacity and electric transmission capacity may impair our ability to meet customers existing and future requirements.

In order to meet existing and future customer demands for natural gas and electricity, we must acquire sufficient supplies of natural gas and electricity, interstate pipeline transmission and storage capacity, and electric transmission capacity to serve such requirements. We must contract for reliable and adequate upstream transmission capacity for our distribution systems while considering the dynamics of the interstate pipeline and storage and electric transmission markets, our own on-system resources, as well as the characteristics of our markets. Our financial condition and results of operations would be materially and adversely affected if the future availability of these capacities were insufficient to meet future customer demands for natural gas and electricity. Currently, our Florida natural gas operation relies primarily on one pipeline system, FGT, for most of its natural gas supply and transmission. Our Florida electric operation relies primarily on two suppliers, Gulf Power for the northwest service territory and JEA for the northeast service territory. Any interruption to these systems could adversely affect our ability to meet the demands of FPU's customers and our earnings.

Commodity price increases may adversely affect the operating costs and competitive positions of our natural gas, electric and propane distribution operations, which may adversely affect our results of operations, cash flows and financial condition.

Natural Gas/Electric. Higher natural gas prices can significantly increase the cost of gas billed to our natural gas customers. Increases in the cost of coal, natural gas and other fuels used to generate electricity can significantly increase the cost of electricity billed to our electric customers. Damage to the production or transportation facilities of our suppliers, decreasing their supply of natural gas and electricity, could result in increased supply costs and higher prices for our customers. Such cost increases generally have no immediate effect on our revenues and net income because of our regulated fuel cost recovery mechanisms. Our net income, however, may be reduced by higher expenses that we may incur for uncollectible customer accounts and by lower volumes of natural gas and electricity deliveries when customers reduce their consumption. Therefore, increases in the price of natural gas, coal and other fuels can affect our operating cash flows and the competitiveness of natural gas and electricity as energy sources and consequently have an adverse effect on our operating cash flows.

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Propane. Propane costs are subject to volatile changes as a result of product supply or other market conditions, including weather and economic and political factors affecting crude oil and natural gas supply or pricing. For example, weather conditions could damage production or transportation facilities, which could result in decreased supplies of propane, increased supply costs and higher prices for customers. Such cost changes can occur rapidly and can affect profitability. There is no assurance that we will be able to pass on propane cost increases fully or immediately, particularly when propane costs increase rapidly. Therefore, average retail sales prices can vary significantly from year to year as product costs fluctuate in response to propane, fuel oil, crude oil and natural gas commodity market conditions. In addition, in periods of sustained higher commodity prices, declines in retail sales volumes due to reduced consumption and increased amounts of uncollectible accounts may adversely affect net income.

Our propane inventory is subject to inventory valuation risk, which may result in a write-down of inventory.

Our propane distribution operations own bulk propane storage facilities, with an aggregate capacity of approximately 3.4 million gallons. We purchase and store propane based on several factors, including inventory levels and the price outlook. We may purchase large volumes of propane at current market prices during periods of low demand and low prices, which generally occur during the summer months. Propane is a commodity, and as such, its price is subject to volatile fluctuations in response to changes in supply or other market conditions. We have no control over these market conditions. Consequently, the wholesale price of the propane that we purchase can change rapidly over a short period of time. The retail market price for propane could fall below the price at which we made the purchases, which would adversely affect our profits or cause sales from that inventory to be unprofitable. In addition, falling propane prices may result in inventory write-downs as required by accounting principles generally accepted in the United States of America (GAAP) if the market price of propane falls below our weighted average cost of inventory, which could adversely affect net income.

Operating events affecting public safety and the reliability of our natural gas and electric distribution and transmission systems could adversely affect our operations and increase our costs.

Our natural gas and electric operations are exposed to operational events and risks, such as major leaks, outages, mechanical failures and breakdown, operations below expected level of performance or efficiency and accidents that could affect public safety and the reliability of our distribution and transmission systems, significantly increase costs and cause loss of customer confidence. If we are unable to recover from customers through the regulatory process, all or some of these costs and our authorized rate of return, our results of operations, financial condition and cash flows could be adversely affected.

We operate in a competitive environment and we may lose customers to competitors.

Natural Gas. Our natural gas marketing operations compete with third-party suppliers to sell natural gas to commercial and industrial customers. Our natural gas transmission and distribution operations compete with interstate pipelines when our transmission and/or distribution customers are located close enough to a competing pipeline to make direct connections economically feasible. Failure to retain and grow our customer base in the natural gas operations would have an adverse effect on our financial condition, cash flows and results of operations.

Electric. While there is active wholesale power sales competition in Florida, our retail electric business through FPU has remained substantially free from direct competition from other electric service providers. Generally, however, our retail electric business through FPU remains subject to competition from other energy sources. Changes in the competitive environment caused by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect our results of operations, cash flows and financial condition.

Propane. Our propane distribution operations compete with other propane distributors, primarily on the basis of service and price. Some of our competitors have significantly greater resources. Our ability to grow the propane distribution business is contingent upon capturing additional market share, expanding into new markets, and successfully utilizing pricing programs that retain and grow our customer base. Failure to retain and grow our customer base in our propane distribution operations would have an adverse effect on our results of operations, cash flows and financial condition.

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

Energy conservation could lower energy consumption and adversely affect our earnings.

We have seen various legislative and regulatory initiatives to promote energy efficiency and conservation at both federal and state levels. In response to the initiatives in the states, in which we operate, we have put into place programs to promote energy efficiency by our current and potential customers. To the extent a PSC allows us to recover the cost of such energy efficiency promotion, funding for such programs is recovered through the rates we charge to our regulated customers. However, lower energy consumption as a result of energy efficiency and conservation by current and potential customers may adversely affect our results of operations, cash flows and financial condition.

Changes in technology may adversely affect our advanced information services subsidiary's competitiveness.

BravePoint participates in a market that is characterized by rapidly changing technology and accelerating product introduction cycles. The success of our advanced information services subsidiary depends upon our ability to address the rapidly changing needs of our customers by developing and supplying high-quality, cost-effective products, product enhancements and services, on a timely basis, and by keeping pace with technological developments and emerging industry standards. There is no assurance that we will be able to keep up with technological advancements to the degree necessary to keep our products and services competitive.

Our use of derivative instruments may adversely affect our results of operations.

Fluctuating commodity prices may affect our earnings and financing costs because our propane distribution and wholesale marketing operations use derivative instruments, including forwards, futures, swaps and puts, to hedge price risk. In addition, we have utilized in the past, and may decide, after further evaluation, to continue to utilize derivative instruments to hedge price risk. While we have risk management policies and operating procedures in place to control our exposure to risk, if we purchase derivative instruments that are not properly matched to our exposure, our results of operations, cash flows, and financial condition may be adversely affected.

Changes in customer growth may affect earnings and cash flows.

Our ability to increase gross margins in our regulated energy and unregulated propane distribution businesses is dependent upon growth in the residential construction market, adding new commercial and industrial customers and conversion of customers to natural gas, electricity or propane from other energy sources. Slowdowns in growth may adversely affect our gross margin, earnings and cash flows.

Our businesses are capital intensive, and the increased costs and/or delays of capital projects may adversely affect our future earnings.

Our businesses are capital intensive and require significant investments in on-going infrastructure projects. There are limited materials and qualified vendors that can be used in our projects. Our ability to timely complete our infrastructure projects and manage the overall cost of those projects is affected by the availability of the necessary materials and qualified vendors. Our future earnings could be adversely affected if we are unable to manage such capital projects effectively, or if full recovery of such capital costs is not permitted in future regulatory proceedings.

Our regulated energy business may be at risk if franchise agreements are not renewed.

Our regulated natural gas and electric distribution operations hold franchises in each of the incorporated municipalities that require franchise agreements in order to provide natural gas and electricity. Our natural gas and electric distribution operations are currently in negotiations for franchises with certain municipalities for new service areas and renewal of some existing franchises. Ongoing financial results would be adversely impacted from the loss of service to certain operating areas within our electric or natural gas territories in the event that franchise agreements were not renewed.

A strike, work stoppage or a labor dispute could adversely affect our operations.

We are party to collective bargaining agreements with various labor unions at some of our Florida operations. A strike, work stoppage or a labor dispute with a union or employees represented by a union could cause interruption to our operations. If a strike, work stoppage or other labor dispute were to occur, our results could be adversely affected.

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Accidents, natural disasters, severe weather (such as a major hurricane) and acts of terrorism could adversely impact earnings.

Inherent in energy transmission and distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, fires, explosions, sabotage and mechanical problems. Natural disasters and severe weather may damage our assets, cause operational interruptions and result in the loss of human life. The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas, electricity and propane that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. The insurance industry may also be affected by natural disasters, severe weather and acts of terrorism, and as a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms, which could adversely affect our results of operations, financial condition and cash flows.

A security breach disrupting our operating systems and facilities or exposing confidential information may adversely affect our reputation, disrupt our operations and increase our costs.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to system disruptions or generate facility shutdowns. If such an attack or security breach were to occur, our business, results of operations and financial condition could be adversely affected. Additionally, the protection of customer, employee and Company data is crucial to our operational security. A breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could occur and have an adverse effect on our reputation, results of operations and financial condition. A breakdown or breach could also materially increase our costs of maintaining our system and protecting it against future breakdowns or breaches. We take reasonable precautions to safeguard our information systems from cyber-attacks and security breaches; however, there is no guarantee that the procedures implemented to protect against unauthorized access to our information systems are adequate to safeguard against all attacks and breaches.

Regulatory, Legal and Environmental Risks

Regulation of our businesses, including changes in the regulatory environment, may adversely affect our results of operations, cash flows and financial condition.

The Delaware, Maryland and Florida PSCs regulate our utility operations in those states. Eastern Shore is regulated by the FERC. The PSCs and the FERC set the rates that we can charge customers for services subject to their regulatory jurisdiction. Our ability to obtain timely future rate increases and rate supplements to maintain current rates of return depends on regulatory approvals, and there can be no assurance that our regulated operations will be able to obtain such approvals or maintain currently authorized rates of return. When our earnings from the regulated utilities exceed the authorized rate of return, the respective PSC or the FERC in the case of Eastern Shore may require us to reduce our rates charged to customers in the future.

We are dependent upon construction of new facilities to support future growth in earnings in our natural gas and electric distribution and natural gas transmission operations.

Construction of new facilities required to support future growth is subject to various regulatory and developmental risks, including but not limited to: (a) our ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on terms that are acceptable to us; (b) potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project; (c) inability to acquire rights-of-way or land rights on a timely basis on terms that are acceptable to us; (d) lack of anticipated future growth in available natural gas and electricity supply; and (e) insufficient customer throughput commitments.

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We are subject to operating and litigation risks that may not be fully covered by insurance.

Our operations are subject to the operating hazards and risks normally incidental to handling, storing, transporting, transmitting and delivering natural gas, electricity and propane to end users. From time to time, we are a defendant in legal proceedings arising in the ordinary course of business. We maintain insurance policies with insurers to cover our general liabilities in the amount of \$51 million, which we believe are reasonable and prudent. There can be no assurance, however, that such insurance will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices.

We may face certain regulatory and financial risks related to pipeline safety legislation.

A number of legislative proposals to implement increased oversight over natural gas pipeline operations and increased investment in facilities to inspect pipeline facilities, upgrade pipeline facilities, or control the impact of a breach of such facilities are pending at the federal level. Additional operating expenses and capital expenditures may be necessary to remain in compliance with the increased federal oversight resulting from such proposals. If such legislation is adopted and we incur additional expenses and expenditures as a result, our financial condition, results of operations and cash flows could be adversely affected, particularly if we are not authorized through the regulatory process to recover from customers some or all of these costs and our authorized rate of return.

Costs of compliance with environmental laws may be significant.

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These evolving laws and regulations may require expenditures over a long period of time to control environmental effects at our current and former operating sites, especially former manufactured gas plant (MGP) sites. Compliance with these legal obligations requires us to commit capital. If we fail to comply with environmental laws and regulations, even if such failure is caused by factors beyond our control, we may be assessed civil or criminal penalties and fines.

To date, we have been able to recover, through regulatory rate mechanisms, the costs associated with the remediation of former MGP sites. There is no guarantee, however, that we will be able to recover future remediation costs in the same manner or at all. A change in our approved rate mechanisms for recovery of environmental remediation costs at former MGP sites could adversely affect our results of operations, cash flows and financial condition.

Further, existing environmental laws and regulations may be revised, or new laws and regulations seeking to protect the environment may be adopted and be applicable to us. Revised or additional laws and regulations could result in additional operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable.

Derivatives legislation and the implementation of related rules could have an adverse impact on our ability to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) regulates derivative transactions, which include certain instruments used in our risk management activities. The Dodd-Frank Act contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility, subject to certain exceptions for entities that use swaps to hedge or mitigate commercial risk. Although the Dodd-Frank Act includes significant new provisions regarding the regulation of derivatives, the impact of those requirements will not be known definitively until regulations have been adopted and fully implemented by both the SEC and the Commodities Futures Trading Commission, and market participants establish registered clearing facilities under those regulations. The legislation and any new regulations could increase the operational and transactional cost of derivatives contracts and affect the number and/or creditworthiness of available counterparties.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The adoption of this type of legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas and propane or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

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ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

(a) General

We own offices and operate facilities in the following locations: Pocomoke, Salisbury, Cambridge, Easton, Elkton and Princess Anne, Maryland; Dover, Seaford, Laurel and Georgetown, Delaware; Lecato, Virginia; and West Palm Beach, DeBary, Inglis, Indiantown, Marianna, Lantana, Lauderdale, Fernandina Beach, Micco, Newberry, Clewiston, Okeechobee, and Winter Haven, Florida. We rent office space in Dover and Ocean View, Delaware; West Palm Beach, Fernandina Beach, Clewiston, Okeechobee, and Lecato, Florida; Chincoteague and Belle Haven, Virginia; Colora and Centerville, Maryland; Honey Brook, Blakeslee, Mount Pocono and Allentown, Pennsylvania; Houston, Texas; and Norcross, Georgia. In general, we believe that our offices and facilities are adequate for the uses for which they are employed.

(b) Natural Gas Distribution

Our Delmarva natural gas distribution operation owns approximately 1,162 miles of natural gas distribution mains (together with related service lines, meters and regulators) located in our Delaware and Maryland service areas. Our Florida natural gas distribution operation owns 2,532 miles of natural gas distribution mains (and related equipment). In addition, we have adequate gate stations to handle receipt of the gas in each of the distribution systems. We also own facilities in Delaware and Maryland, which we use for propane-air injection during periods of peak demand.

(c) Natural Gas Transmission

Eastern Shore owns and operates approximately 428 miles of transmission pipeline, extending from supply interconnects at Parkesburg, Daleville and Honey Brook, Pennsylvania; and Hockessin, Delaware, to approximately 93 delivery points in southeastern Pennsylvania, Delaware and the eastern shore of Maryland.

Peninsula Pipeline owns and operates approximately eight miles of transmission pipeline in Suwanee County, Florida. Peninsula Pipeline also owns approximately 45 percent of the 16-mile pipeline extending from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. The remaining 55 percent of the pipeline is owned by Peoples Gas.

(d) Electric Distribution

Our electric distribution operation owns and operates 20 miles of electric transmission line located in northeast Florida and 878 miles of electric distribution line located in northeast and northwest Florida.

(e) Propane Distribution and Wholesale Marketing

Our Delmarva propane distribution operation owns bulk propane storage facilities, with an aggregate capacity of approximately 2.7 million gallons, at 31 plant facilities in Delaware, Maryland, Pennsylvania and Virginia, located on real estate that is either owned or leased by our Company. Our Florida propane distribution operation owns 32 bulk propane storage facilities with a total capacity of 732,000 gallons. Xeron does not own physical storage facilities or equipment to transport propane; however, it leases propane storage and pipeline capacity from non-affiliated third parties.

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(f) Lien

All of the properties owned by FPU are subject to a lien in favor of the holders of its first mortgage bonds securing its indebtedness under its Mortgage Indenture and Deed of Trust. FPU owns offices and operates facilities in the following locations: West Palm Beach, DeBary, Inglis, Indiantown, Marianna, Lantana, Lauderhill, Fernandina Beach, Micco, Newberry, Clewiston and Okeechobee, Florida. FPU's natural gas distribution operation owns 1,722 miles of natural gas distribution mains (and related equipment) in its service areas. FPU's electric distribution operation owns and operates 20 miles of electric transmission line located in northeast Florida and 878 miles of electric distribution line located in northeast and northwest Florida. FPU's propane distribution operation owns 32 bulk propane storage facilities with a total capacity of 732,000 gallons located in south and central Florida.

ITEM 3. LEGAL PROCEEDINGS.

(a) General

As disclosed in Item 8 under the heading "Notes to the Consolidated Financial Statements - Note 19, Other Commitments and Contingencies," we are involved in various legal actions and claims arising in the normal course of business. We are also involved in certain administrative proceedings before various governmental or regulatory agencies concerning rates. In the opinion of management, the ultimate disposition of these current proceedings will not have a material effect on our consolidated financial position, results of operations or cash flows.

(b) Environmental

See discussion of environmental commitments and contingencies in Item 8 under the heading "Notes to the Consolidated Financial Statements Note 18, Environmental Commitments and Contingencies."

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

Table of Contents**ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT.**

Set forth below are the names, ages, and positions of our executive officers with their recent business experience. The age of each officer is as of the filing date of this report.

Name	Age	Position
Michael P. McMasters	54	President and Chief Executive Officer
Beth W. Cooper	46	Senior Vice President and Chief Financial Officer
Stephen C. Thompson	52	Senior Vice President and President, Eastern Shore
Elaine B. Bittner	43	Vice President of Strategic Development

Michael P. McMasters was appointed Chief Executive Officer effective January 1, 2011. He was appointed President on March 1, 2010 and was elected a director in 2010. Prior to his appointments and election, Mr. McMasters served as Executive Vice President and Chief Operating Officer since September 2008, Chief Financial Officer from 1997 to 2008 and Senior Vice President since 2004 to 2008. He has previously held the positions of Vice President, Treasurer, Director of Accounting and Rates, and Controller of the Company. In addition to his tenure with Chesapeake, Mr. McMasters also served as Director of Operations Planning for Equitable Gas Company. He has 33 years of experience in the utilities industry.

Beth W. Cooper was appointed Senior Vice President and Chief Financial Officer in September 2008 and Corporate Secretary in June 2005. Previously, she has served as Vice President from June 2005 to September 2008 and Treasurer from 2003 to May of 2012. Ms. Cooper joined the Company in 1990 and has previously served in the following roles: Assistant Vice President, Assistant Treasurer, Assistant Secretary, Director of Internal Audit and Director of Strategic Planning. Before joining the Company, Ms. Cooper was an auditor with Ernst & Young's Entrepreneurial Services Group. She has 22 years of experience in the utilities industry.

Stephen C. Thompson was appointed Senior Vice President in 2004. Mr. Thompson is also President of Eastern Shore. Mr. Thompson joined the Company in 1983 and during his tenure has served as Senior Vice President and Vice President of the Company. Mr. Thompson also served as Director of Gas Supply and Marketing, Superintendent of Eastern Shore, and Regional Manager for the Florida distribution operations. Mr. Thompson has 29 years of experience in the utilities industry.

Elaine B. Bittner was appointed Vice President of Strategic Development in June of 2010. Previously, she has held various positions within the Company including Vice President of Eastern Shore from 2005 to 2010, Director of Eastern Shore, Director of Customer Services and Regulatory Affairs for Eastern Shore, Director of Environmental Affairs for Chesapeake and Environmental Engineer. Prior to joining the Company, Ms. Bittner was a Project Chemist, Client Consultant and Environmental Lab Chemist in the environmental industry specializing in environmental analysis and reporting related to volatile organic compounds. Ms. Bittner has 16 years of experience in the utilities industry.

Table of Contents**PART II****ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTER AND ISSUER PURCHASES OF EQUITY SECURITIES.****(a) Common Stock Price Ranges, Common Stock Dividends and Shareholder Information:**

Our common stock is listed on the NYSE under the symbol CPK. The high, low and closing prices of our common stock and dividends declared per share for each calendar quarter during 2012 and 2011 were as follows:

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
2012					
	March 31	\$ 43.83	\$ 39.89	\$ 41.12	\$ 0.345
	June 30	\$ 45.15	\$ 40.22	\$ 43.72	\$ 0.365
	September 30	\$ 48.51	\$ 43.65	\$ 47.36	\$ 0.365
	December 31	\$ 48.92	\$ 41.17	\$ 45.40	\$ 0.365
2011					
	March 31	\$ 42.47	\$ 37.67	\$ 41.62	\$ 0.330
	June 30	\$ 43.14	\$ 37.66	\$ 40.03	\$ 0.345
	September 30	\$ 41.50	\$ 36.00	\$ 40.11	\$ 0.345
	December 31	\$ 44.53	\$ 38.30	\$ 43.35	\$ 0.345

 Holders

At February 28, 2013, there were 2,348 holders of record of Chesapeake common stock.

 Dividends

We have paid a cash dividend to common stock shareholders for 52 consecutive years. Dividends are payable at the discretion of our Board of Directors. Future payment of dividends, and the amount of these dividends, will depend on our financial condition, results of operations, capital requirements, and other factors. We declared quarterly cash dividends on our common stock in 2012 and 2011, totaling \$1.440 per share and \$1.365 per share, respectively.

Indentures to our long-term debt contain various restrictions. In terms of restrictions which limit the payment of dividends by Chesapeake, each of its unsecured senior notes contains a Restricted Payments covenant. The most restrictive covenants of this type are included within the 7.83 percent Senior Notes, due January 1, 2015. The covenant provides that Chesapeake cannot pay or declare any dividends or make any other Restricted Payments (such as dividends) in excess of the sum of \$10.0 million plus consolidated net income of the Company accrued on and after January 1, 2001. As of December 31, 2012, Chesapeake's cumulative consolidated net income base was \$185.3 million, offset by Restricted Payments of \$103.0 million, leaving \$82.3 million of cumulative net income free of restrictions.

Each series of FPU's first mortgage bonds contains a similar restriction that limits the payment of dividends by FPU. The most restrictive covenants of this type are included within the series that is due in 2022, which provides that FPU cannot make dividend or other restricted payments in excess of the sum of \$2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2012, FPU had a cumulative net income base of \$85.1 million, offset by restricted payments of \$37.6 million, leaving \$47.5 million of cumulative net income of FPU free of restrictions based on this covenant.

 Recent Sales of Unregistered Securities

No securities were sold during the year 2012 that were not registered under the Securities Act of 1933, as amended.

Table of Contents**(b) Purchases of Equity Securities by the Issuer**

The following table sets forth information on purchases by or on behalf of Chesapeake of shares of its common stock during the quarter ended December 31, 2012.

Period	Total	Average	Total Number of Shares	Maximum Number of
	Number of Shares Purchased		Purchased as Part of Publicly Announced Plans or Programs (2)	Shares That May Yet Be Purchased Under the Plans or Programs (2)
October 1, 2012 through October 31, 2012 ⁽¹⁾	250	\$ 48.31		
November 1, 2012 through November 30, 2012				
December 1, 2012 through December 31, 2012				
Total	250	\$ 48.31		

⁽¹⁾ Chesapeake purchased shares of common stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading "Notes to the Consolidated Financial Statements - Note 15, Employee Benefit Plans." During the quarter, 250 shares were purchased through the reinvestment of dividends on deferred stock units.

⁽²⁾ Except for the purpose described in Footnote ⁽¹⁾, Chesapeake has no publicly announced plans or programs to repurchase its shares. Discussion of our compensation plans, for which shares of Chesapeake common stock are authorized for issuance, is included in the portion of the Proxy Statement captioned "Equity Compensation Plan Information" to be filed no later than March 31, 2013, in connection with our Annual Meeting to be held on or about May 2, 2013, and is incorporated herein by reference.

(c) Chesapeake Utilities Corporation Common Stock Performance Graph

The following Stock Performance graph compares cumulative total stockholder return on a hypothetical investment in our common stock during the five fiscal years ended December 31, 2012, with the cumulative total stockholder return on a hypothetical investment in both (i) the Standard & Poor's 500 Index ("S&P 500 Index"), and (ii) an industry index consisting of Chesapeake and 10 companies from the current Edward Jones Natural Gas Distribution Group, a published listing of selected gas distribution utilities' results. The Compensation Committee compares the performance of the companies from the Edward Jones Natural Gas Distribution Group to our performance for purposes of determining the level of long-term performance awards earned by our named executive officers.

The 10 companies from the current Edward Jones Natural Gas Distribution Group are: AGL Resources, Inc., Atmos Energy Corporation, Delta Natural Gas Company, Inc., The Laclede Group, Inc., New Jersey Resources Corporation, Northwest Natural Gas Company, Piedmont Natural Gas Company, Inc., RGC Resources, Inc., South Jersey Industries, Inc., and WGL Holdings, Inc.

The comparison assumes \$100 was invested on December 31, 2007 in our common stock and in each of the foregoing indices and assumes reinvested dividends. The comparisons in the graph below are based on historical data and are not intended to forecast the possible future performance of our common stock.

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	2007	2008	2009	2010	2011	2012
Chesapeake	\$ 100	\$ 103	\$ 109	\$ 145	\$ 156	\$ 169
Industry Index	\$ 100	\$ 107	\$ 111	\$ 130	\$ 151	\$ 147
S&P 500	\$ 100	\$ 63	\$ 80	\$ 92	\$ 94	\$ 109

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For the Years Ended December 31,	2012	2011	2010
<u>Operating</u> ⁽¹⁾			
<i>(in thousands)</i>			
Revenues			
Regulated Energy	\$ 246,208	\$ 256,226	\$ 269,438
Unregulated Energy	133,049	149,586	146,793
Other	13,245	12,215	11,315
Total revenues	\$ 392,502	\$ 418,027	\$ 427,546
Operating income			
Regulated Energy	\$ 46,999	\$ 43,911	\$ 43,267
Unregulated Energy	8,355	9,619	8,150
Other	1,281	175	513
Total operating income	\$ 56,635	\$ 53,705	\$ 51,930
Net income from continuing operations	\$ 28,863	\$ 27,622	\$ 26,056
<u>Assets</u>			
<i>(in thousands)</i>			
Gross property, plant and equipment	\$ 697,159	\$ 625,488	\$ 584,385
Net property, plant and equipment	\$ 541,781	\$ 487,704	\$ 462,757
Total assets	\$ 733,746	\$ 709,066	\$ 670,993
Capital expenditures ⁽¹⁾	\$ 78,210	\$ 44,431	\$ 46,955
<u>Capitalization</u>			
<i>(in thousands)</i>			
Stockholders' equity	\$ 256,598	\$ 240,780	\$ 226,239
Long-term debt, net of current maturities	101,907	110,285	89,642
Total capitalization	\$ 358,505	\$ 351,065	\$ 315,881
Current portion of long-term debt	8,196	8,196	9,216
Short-term debt	61,199	34,707	63,958
Total capitalization and short-term financing	\$ 427,900	\$ 393,968	\$ 389,055

(1) These amounts exclude the results of distributed energy and water services due to their reclassification to discontinued operations. We closed our distributed energy operation in 2007. All assets of the water businesses were sold in 2004 and 2003. These amounts also include accruals for capital expenditures that we have incurred for each reporting period.

(2) These amounts include the financial position and results of operation of FPU for the period from the merger (October 28, 2009) to December 31, 2009. These amounts also include the effects of acquisition accounting and issuance of Chesapeake common shares as a result of the merger.

(3) FASB ASC 718, Compensation - Stock Compensation, and FASB ASC 715, Compensation - Retirement Plans, were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

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2009 ⁽²⁾	2008	2007	2006 ⁽³⁾	2005	2004	2003
\$ 138,671	\$ 116,123	\$ 128,566	\$ 124,438	\$ 124,445	\$ 98,037	\$ 91,990
119,973	161,290	115,190	94,320	90,995	67,607	59,197
10,141	14,030	14,530	12,442	14,045	12,311	12,381
\$ 268,785	\$ 291,443	\$ 258,286	\$ 231,200	\$ 229,485	\$ 177,955	\$ 163,568
\$ 26,668	\$ 23,833	\$ 21,739	\$ 18,618	\$ 16,278	\$ 16,270	\$ 16,208
8,390	3,600	5,244	3,650	4,167	3,185	4,321
(1,322)	1,046	1,131	1,064	1,476	722	1,050
\$ 33,736	\$ 28,479	\$ 28,114	\$ 23,332	\$ 21,921	\$ 20,177	\$ 21,579
\$ 15,897	\$ 13,607	\$ 13,218	\$ 10,748	\$ 10,699	\$ 9,686	\$ 10,079
\$ 543,905	\$ 381,689	\$ 352,838	\$ 325,836	\$ 280,345	\$ 250,267	\$ 234,919
\$ 436,587	\$ 280,671	\$ 260,423	\$ 240,825	\$ 201,504	\$ 177,053	\$ 167,872
\$ 615,811	\$ 385,795	\$ 381,557	\$ 325,585	\$ 295,980	\$ 241,938	\$ 222,058
\$ 26,294	\$ 30,844	\$ 30,142	\$ 49,154	\$ 33,423	\$ 17,830	\$ 11,822
\$ 209,781	\$ 123,073	\$ 119,576	\$ 111,152	\$ 84,757	\$ 77,962	\$ 72,939
98,814	86,422	63,256	71,050	58,991	66,190	69,416
\$ 308,595	\$ 209,495	\$ 182,832	\$ 182,202	\$ 143,748	\$ 144,152	\$ 142,355
35,299	6,656	7,656	7,656	4,929	2,909	3,665
30,023	33,000	45,664	27,554	35,482	5,002	3,515
\$ 373,917	\$ 249,151	\$ 236,152	\$ 217,412	\$ 184,159	\$ 152,063	\$ 149,535

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For the Years Ended December 31,	2012	2011	2010
Common Stock Data and Ratios			
Basic earnings per share from continuing operations ⁽¹⁾	\$ 3.01	\$ 2.89	\$ 2.75
Diluted earnings per share from continuing operations ⁽¹⁾	\$ 2.99	\$ 2.87	\$ 2.73
Return on average equity from continuing operations ⁽¹⁾	11.6%	11.6%	11.6%
Common equity / total capitalization	71.6%	68.6%	71.6%
Common equity / total capitalization and short-term financing	60.0%	61.1%	58.2%
Book value per share	\$ 26.74	\$ 25.15	\$ 23.75
Market price:			
High	\$ 48.920	\$ 44.530	\$ 42.200
Low	\$ 39.890	\$ 36.000	\$ 28.010
Close	\$ 45.400	\$ 43.350	\$ 41.520
Average number of shares outstanding	9,586,144	9,555,799	9,474,554
Shares outstanding at year-end	9,597,499	9,567,307	9,524,195
Registered common shareholders	2,396	2,481	2,482
Cash dividends declared per share	\$ 1.44	\$ 1.37	\$ 1.31
Dividend yield (annualized) ⁽⁴⁾	3.2%	3.2%	3.2%
Payout ratio from continuing operations ^{(1) (5)}	47.8%	47.4%	47.6%
Additional Data			
Customers			
Natural gas distribution	124,015	121,934	120,230
Electric distribution	31,066	30,986	30,966
Propane distribution	49,312	48,824	48,100
Volumes			
Natural gas deliveries (in Dts)	66,784,690	57,493,022	49,310,314
Electric Distribution (in MWHs)	670,998	694,653	751,507
Propane distribution (in thousands of gallons)	37,438	37,387	39,807
Heating degree-days (Delmarva Peninsula)			
Actual HDD	3,936	4,221	4,831
10-year average HDD (normal)	4,491	4,499	4,528
Heating degree-days (Florida)			
Actual HDD	633	753	1,501
10-year average HDD (normal)	915	920	863
Cooling degree-days (Florida)			
Actual CDD	2,871	2,858	2,859
10-year average CDD (normal)	2,756	2,718	2,695
Propane bulk storage capacity (in thousands of gallons)	3,400	3,351	3,041
Total employees ⁽¹⁾	738	711	734

(1) These amounts exclude the results of distributed energy and water services due to their reclassification to discontinued operations. We closed our distributed energy operation in 2007. All assets of the water businesses were sold in 2004 and 2003.

(2) These amounts include the financial position and results of operation of FPU for the period from the merger closing (October 28, 2009) to December 31, 2009.

(3) FASB ASC 718, Compensation - Stock Compensation, and FASB ASC 715, Compensation - Retirement Plans, were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

(4) Dividend yield (annualized) is calculated by multiplying the fourth quarter dividend by four (4), then dividing that amount by the closing common stock price at December 31.

(5)

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The payout ratio from continuing operations is calculated by dividing cash dividends declared per share (for the year) by basic earnings per share from continuing operations.

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2009 ⁽²⁾	2008	2007	2006 ⁽³⁾	2005	2004	2003
\$ 2.17	\$ 2.00	\$ 1.96	\$ 1.78	\$ 1.83	\$ 1.68	\$ 1.80
\$ 2.15	\$ 1.98	\$ 1.94	\$ 1.76	\$ 1.81	\$ 1.64	\$ 1.76
11.2%	11.2%	11.5%	11.0%	13.2%	12.8%	14.4%
68.0%	58.7%	65.4%	61.0%	59.0%	54.1%	51.2%
56.1%	49.4%	50.6%	51.1%	46.0%	51.3%	48.8%
\$ 22.33	\$ 18.03	\$ 17.64	\$ 16.62	\$ 14.41	\$ 13.49	\$ 12.89
\$ 35.000	\$ 34.840	\$ 37.250	\$ 35.650	\$ 35.780	\$ 27.550	\$ 26.700
\$ 22.020	\$ 21.930	\$ 28.000	\$ 27.900	\$ 23.600	\$ 20.420	\$ 18.400
\$ 32.050	\$ 31.480	\$ 31.850	\$ 30.650	\$ 30.800	\$ 26.700	\$ 26.050
7,313,320	6,811,848	6,743,041	6,032,462	5,836,463	5,735,405	5,610,592
9,394,314	6,827,121	6,777,410	6,688,084	5,883,099	5,778,976	5,660,594
2,670	1,914	1,920	1,978	2,026	2,026	2,069
\$ 1.25	\$ 1.21	\$ 1.18	\$ 1.16	\$ 1.14	\$ 1.12	\$ 1.10
3.9%	3.9%	3.7%	3.8%	3.7%	4.2%	4.2%
57.6%	60.5%	60.2%	65.2%	62.3%	66.7%	61.1%
117,887	65,201	62,884	59,132	54,786	50,878	47,649
31,030						
48,680	34,981	34,143	33,282	32,117	34,888	34,894
50,159,227	46,539,142	42,910,964	41,826,357	43,716,921	39,469,915	37,478,009
105,739						
32,546	27,956	29,785	24,243	26,178	24,979	25,147
4,729	4,431	4,504	3,931	4,792	4,553	4,715
4,462	4,401	4,376	4,372	4,436	4,389	4,409
911						
849						
2,770						
2,687						
3,042	2,471	2,441	2,315	2,315	2,045	2,195
757	448	445	437	423	426	439

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This section provides management's discussion of Chesapeake and its consolidated subsidiaries, with specific information on results of operations, liquidity and capital resources, as well as discussion of how certain accounting principles affect our financial statements. It includes management's interpretation of financial results of the Company and its operating segments, the factors affecting these results, the major factors expected to affect future operating results as well as investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A, Risk Factors. They should be considered in connection with forward-looking statements contained in this report, or otherwise made by or on behalf of us, since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

The following discussions and those later in the document on operating income and segment results include the use of the term gross margin. Gross margin is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by the Company under its allowed rates for regulated energy operations and under its competitive pricing structure for unregulated natural gas marketing and propane distribution operations. Our management uses gross margin in measuring our business units' performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

(a) Introduction

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

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

executing a capital investment program in pursuit of organic growth opportunities that generate returns equal to or greater than our cost of capital;

expanding the regulated energy distribution and transmission businesses into new geographic areas and providing new services in our current service territories;

expanding the propane distribution business in existing and new markets through leveraging our community gas system services and our bulk delivery capabilities;

expanding both our regulated energy and unregulated energy businesses through strategic acquisitions;

utilizing our expertise across our various businesses to improve overall performance;

pursuing and entering new unregulated energy markets that will complement our existing strategy and operating units;

enhancing marketing channels to attract new customers;

providing reliable and responsive customer service to existing customers so they become our best promoters;

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

engaging our local communities and governments in a cooperative and mutually beneficial way;

maintaining a capital structure that enables us to access capital as needed;

maintaining a consistent and competitive dividend for shareholders; and

creating and maintaining a diversified customer base, energy portfolio and utility foundation.

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(b) Highlights and Recent Developments

Our net income for 2012 was \$28.9 million, or \$2.99 per share (diluted), compared to \$27.6 million, or \$2.87 per share (diluted), and \$26.1 million, or \$2.73 per share (diluted), for 2011 and 2010, respectively.

Our operations are primarily related to natural gas, electricity and propane, both in the regulated and unregulated sectors, and are generally located on the Delmarva Peninsula and in Florida. We also have an advanced information services subsidiary, which provides both products and consulting services. The following is a summary of key factors affecting our businesses and their impacts on our results. More detailed discussion and analysis are provided in the Results of Operations section.

Growth

We continue to see growth in our natural gas businesses from our efforts over the past several years to expand our services by delivering clean-burning, environmentally friendly natural gas to customers. We are identifying and developing additional opportunities that will generate growth over the next several years.

New natural gas transmission services and growth in natural gas distribution customers generated \$3.6 million and \$2.7 million, respectively, in additional gross margin for 2012, compared to 2011. These increases in gross margin were related primarily to the continued execution of our strategic plan, including expansion of natural gas service to new areas and conversion of several large commercial and industrial customers to natural gas. In addition, new services are being initiated by our natural gas transmission subsidiaries in response to increased demand for natural gas service on the Delmarva Peninsula and in Florida, both from our natural gas distribution operations and other unaffiliated customers directly connected to the transmission systems.

Major Expansion Initiatives and Customer Growth Reflected in Results

In late 2011 and during 2012, we expanded natural gas transmission and distribution services to Sussex County, Delaware and Nassau County, Florida and also initiated natural gas transmission service in Worcester and Cecil Counties, Maryland. These major expansion initiatives increased our natural gas footprint, delivering natural gas service to areas where it was not previously available. These initiatives generated \$2.9 million of additional gross margin for our natural gas transmission operations in 2012. Natural gas distribution service to two large industrial customers in Lewes, Delaware and two industrial facilities of an existing customer in southeastern Sussex County, Delaware generated \$588,000 of additional gross margin for 2012. The following table summarizes our major expansion initiatives that have already commenced (dollars in thousands):

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Project	Date of New Service	2011 Margin	2012 Margin	Estimated Annualized Margin
Sussex County, DE expansion				
Transmission (for Lewes, DE) 3,250 Dts/d	Nov-11	\$ 156	\$ 935	\$ 935
Distribution Two large industrial customers in Lewes, DE	Dec-11	1	500	391
Transmission (for southeastern part) 1,550 Dts/d	Mar-12 to May-12		334	446
Distribution Two facilities of an existing customer in the southeastern part of Sussex County	Mar-12 to Aug-12		89	154
		\$ 157	\$ 1,858	\$ 1,926
Cecil County, MD expansion				
Transmission 4,070 Dts/d	Nov-12	\$	\$ 147	\$ 882
Worcester County, MD expansion				
Transmission 1,450 Dts/d	Jun-12 to Jan-13	\$	\$ 90	\$ 391
Nassau County, FL expansion				
Transmission A new fixed annual rate service ⁽¹⁾	Apr-12	\$	\$ 1,537	\$ 2,100
		\$ 157	\$ 3,632	\$ 5,299
Total by Geographic Location of the Project:				
Delmarva Natural Gas Distribution		\$ 1	\$ 589	\$ 545
Delmarva Natural Gas Transmission		156	1,506	2,654
Florida Natural Gas Transmission			1,537	2,100
		\$ 157	\$ 3,632	\$ 5,299

- ⁽¹⁾ Peninsula Pipeline commenced its service in April 2012, using compressed natural gas while a new pipeline was being constructed. The new pipeline was completed and placed in service in December 2012. Peninsula Pipeline is expected to incur approximately \$800,000 in annual transportation costs upon the completion of the new pipeline, which will reduce this gross margin.

Other Growth

In addition to the recent expansion initiatives, the Delmarva natural gas distribution operation has added 12 new large industrial and commercial customers since the beginning of 2011, which generated \$574,000 in additional gross margin in 2012, compared to 2011. Growth in residential and other commercial customers on the Delmarva Peninsula generated \$513,000 in additional gross margin in 2012. Customer growth in Florida, primarily from commercial and industrial customers, generated \$986,000 in additional gross margin in 2012.

Future Major Expansion Initiatives and Opportunities

Although not affecting results in 2012, Eastern Shore entered into precedent agreements with NRG Energy Center Dover LLC (NRG) and PBF Energy Inc. (Delaware City Refinery) to further expand its transmission system in order to provide additional services to these customers. Eastern Shore expects to enter into firm transportation service agreements with NRG and Delaware City Refinery upon satisfaction of certain conditions pursuant to the respective precedent agreements. These additional services are expected to be initiated in late 2013. A delay in obtaining the regulatory approval from the FERC for construction of these new facilities could delay the service initiation.

In Florida, Peninsula Pipeline entered into a firm transportation agreement with an unaffiliated utility, which will generate an estimated annual gross margin of approximately \$840,000. This service is expected to be initiated in the second quarter of 2013 upon completion of construction of the new facility.

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

Project	Date of New Service	Estimated Annualized Margin
Service to an unaffiliated Florida utility ⁽¹⁾	Apr-13	\$840
Service to NRG's Dover, DE electric generation plant		
Transmission 13,440 Dts/d ⁽²⁾	Nov-13	\$2,400 to \$2,800
Delaware City refinery expansion		
Transmission 15,000 Dts/d ⁽³⁾	Dec-13	\$1,600
		\$4,840 to \$5,240

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

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

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

As we expand our natural gas service to new areas, first through transmission service and distribution service to large industrial customers, our natural gas distribution operations continue to pursue additional opportunities to provide service to residential and other commercial and industrial customers in those areas. In an effort to increase the availability of natural gas within our Delaware service areas, our Delaware natural gas distribution division filed an application with the Delaware PSC in June 2012 to add several natural gas expansion service offerings. These offerings include a monthly fixed charge in lieu of upfront contributions from customers to extend the distribution system and optional service offerings to assist customers in the process of converting to natural gas. The goal of these new offerings is to meet the energy needs of residents, communities and businesses throughout our service territory, specifically in areas of southeastern Sussex County, where natural gas will now be available. The Delaware PSC is currently reviewing this application.

Acquisition

In June 2012, we entered into an agreement with Eastern Shore Gas Company and its affiliates (collectively ESG, which is not related to our interstate natural gas transmission subsidiary) to purchase their operating assets for approximately \$16.5 million. These assets are currently used to provide propane distribution service to approximately 11,000 residential and commercial customers in Worcester County, Maryland, primarily through underground propane gas distribution systems. We are evaluating the potential conversion of some of these underground propane distribution systems to natural gas where it is economical and feasible. We filed an application with the Maryland PSC for approval of the transaction in August 2012. The transaction, which is also subject to obtaining consents from certain local jurisdictions to the assignment of certain franchise agreements and the satisfaction of other closing conditions, is expected to be completed in 2013. We expect to finance the acquisition using unsecured short-term debt. The acquisition is expected to be accretive to earnings per share in 2013 and thereafter.

Investing in Growth

To continue our growth, we are expanding our resources and capabilities. We are in the early stages of several natural gas distribution expansions on the Delmarva Peninsula, including expansions into Sussex County, Delaware, and Worcester and Cecil Counties in Maryland. These expansions will require not only the construction or conversion of distribution facilities, but also the conversion of customers' appliances or equipment inside their homes. We have begun the process of reorganizing our Delmarva natural gas distribution operation and expect to increase our staff to support these expansions. Secondly, as a result of BravePoint's growth over the last several quarters, BravePoint is continuing to add team members. During 2012, BravePoint's other operating expenses increased by \$1.5 million, compared to 2011, due primarily to the additional staff. Finally, to increase our capacity to appropriately manage future growth, resources have been, and continue to be, added in several key functional areas, including, but not limited to, Human Resources, Communications and Strategic Business Development. During 2012, we incurred \$312,000 in additional acquisition-related costs, compared to 2011, and \$446,000 in new costs associated with increased capacity for future growth. We expect additional increases in costs associated with these key functional areas in the future.

Weather and Consumption

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

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Significantly warmer temperatures in 2012, particularly during the first three months of the year when the demand for natural gas and propane are at their highest, had a large negative impact on our earnings. Lower customer energy consumption directly attributable to warmer temperatures in 2012 reduced gross margin by \$3.6 million, compared to 2011. Temperatures in 2012 on the Delmarva Peninsula and in Florida were seven percent (285 HDD) and 16 percent (120 HDD), respectively, warmer than 2011. Compared to normal, temperatures in 2012 on the Delmarva Peninsula and in Florida were 12 percent (555 HDD) and 31 percent (282 HDD), respectively, warmer and reduced gross margin for 2012 by approximately \$5.1 million, compared to gross margin that we would have generated under normal temperatures.

CDD remained relatively unchanged in 2012 and 2011 (2,871 CDD in Florida in 2012, compared to 2,858 CDD in Florida in 2011) and did not result in a significant variance in our gross margin.

Other Regulatory Matters

In January 2012, the Florida PSC issued an order approving the recovery of \$34.2 million as an acquisition adjustment and \$2.2 million in merger-related costs in connection with Chesapeake's acquisition of FPU in 2009. The inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these assets through amortization expense increase our earnings and cash flows above what we would have achieved absent the regulatory approval. The acquisition adjustment and merger-related costs are to be amortized over 30 years and five years, respectively, beginning in November 2009. Based upon the effective date and outcome of the order, we recorded the amortization as an expense beginning in 2012, which resulted in an increase in amortization expense of \$2.4 million in 2012. We expect to record \$2.4 million (\$1.4 million, net of tax) in amortization expense in 2013, \$2.3 million (\$1.4 million, net of tax) in 2014, and \$1.8 million (\$1.1 million, net of tax) annually thereafter until 2039. In FPU's future rate proceedings, if it is determined that the level of cost savings supporting recovery of the acquisition adjustment no longer exists, the remaining acquisition adjustment may be partially or entirely disallowed by the Florida PSC. If such an event were to occur, we would have to expense the corresponding unamortized amount of the disallowed acquisition adjustment.

In November 2012, the Florida PSC issued an order approving the recognition of a \$1.9 million regulatory liability for FPU for a one-time tax contingency gain, including income tax gross-up, to be amortized over a period from January 2012 to October 2014. This tax contingency gain is related to an income tax liability recorded by FPU prior to the merger with Chesapeake. As the liability no longer exists, upon receiving the Florida PSC order, we recorded an amortization credit of \$684,000 in 2012, which was recorded in the fourth quarter.

In addition to regulatory proceedings, we were involved in a legal dispute over alleged breaches of a franchise agreement by FPU. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. The agreement in principle requires the City of Marianna and FPU to negotiate and prepare a formal settlement agreement that is subject to approval by FPU's Board of Directors and the City Commission of Marianna, Florida (the Marianna Commission). The settlement agreement would contemplate, in pertinent part, the sale of FPU's facilities within the City of Marianna's corporate limits to the City of Marianna and, in connection therewith, require the City of Marianna to enter into an operating agreement with FPU pursuant to which FPU will operate and maintain the facilities sold to the City of Marianna. FPU serves approximately 3,000 customers in the City of Marianna. Total litigation expense associated with the City of Marianna litigation is approximately \$1.4 million as of December 31, 2012. These costs have been expensed as incurred, however, the Florida PSC has permitted FPU to seek recovery in a future rate proceeding. Additional information is presented in Item 8 under the heading Notes to the Consolidated Financial Statements - Note 19, Other Commitments and Contingencies.

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Propane Prices

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

Our propane distribution operations generated additional gross margin of \$2.7 million due to higher retail margins per gallon in 2012, compared to 2011. Sustained retail pricing in response to local market conditions, along with lower propane inventory costs as a result of declining wholesale prices and favorable supply plans, contributed to this increase in retail margins per gallon.

Xeron executed trades with higher margins in 2012, compared to 2011, as the market presented opportunities resulting from fluctuations in wholesale propane prices during 2012. Xeron generated \$225,000 of additional gross margin in 2012, compared to 2011.

Advanced Information Services

In September 2011, BravePoint, our advanced information services subsidiary, released a new product, ProfitZoom , an integrated system encompassing financial, job costing and service management modules, which was designed specifically for the fire protection and specialty contracting industries. ProfitZoom was built as a successor product to another software solution that BravePoint previously marketed and supported for companies in the fire suppression industry. Understanding the needs of the industry and utilizing its technology expertise, BravePoint began developing the ProfitZoom product in 2009. In addition, BravePoint is utilizing a component of ProfitZoom , Application Evolution , to provide services to new and existing customers both in the fire suppression industry and other unrelated businesses. BravePoint generated \$1.4 million in revenue from the sale of these two products and related services during 2012, compared to \$572,000 in 2011. To date, BravePoint has successfully implemented or is currently implementing ProfitZoom for eight customers in the fire suppression industry. Application Evolution is currently utilized by nine customers. These ProfitZoom and Application Evolution contracts are expected to generate approximately \$537,000 in additional revenue over the next 12 months. Additional sales proposals are under consideration by both existing and potential new customers.

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We prepare our financial statements in accordance with GAAP. Application of these accounting principles requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingencies during the reporting period. We base our estimates on historical experience and on various assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Since most of our businesses are regulated and the accounting methods used by these businesses must comply with the requirements of the regulatory bodies, the choices available are limited by these regulatory requirements. In the normal course of business, estimated amounts are subsequently adjusted to actual results that may differ from estimates. Management believes that the following policies require significant estimates or other judgments of matters that are inherently uncertain. These policies and their application have been reviewed by our Audit Committee.

Regulatory Assets and Liabilities

As a result of the ratemaking process, we record certain assets and liabilities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 980, Regulated Operations, and consequently, the accounting principles applied by our regulated energy businesses differ in certain respects from those applied by the unregulated businesses. Costs are deferred when there is a probable expectation that they will be recovered in future revenues as a result of the regulatory process. As more fully described in Item 8 under the heading Notes to the Consolidated Financial Statements Note 2, Summary of Significant Accounting Policies, we have recorded regulatory assets of \$80.1 million and regulatory liabilities of \$45.1 million at December 31, 2012. If we were required to terminate application of ASC Topic 980, we would be required to recognize all such deferred amounts as a charge or a credit to earnings, net of applicable income taxes. Such an adjustment could have a material effect on our results of operations.

Valuation of Environmental Assets and Liabilities

As more fully described in Item 8 under the heading Notes to the Consolidated Financial Statements Note 18, Environmental Commitments and Contingencies, we are currently participating in the investigation, assessment or remediation of six former MGP sites. We have also been in discussions with the Maryland Department of Environment (MDE) regarding a seventh former MGP site. Amounts have been recorded as environmental liabilities and associated environmental regulatory assets based on estimates of future costs to remediate these sites, which are provided by independent consultants, and future recovery of those costs in rates. At December 31, 2012, we had \$10.7 million in environmental liabilities, representing our estimate of such future costs. We also had \$5.9 million in regulatory and other assets, representing the amount of our environmental remediation costs to be recovered in future rates. There is uncertainty in these amounts, because the United States Environmental Protection Agency (EPA), or other applicable state environmental authority, may not have selected the final remediation methods. In addition, there is uncertainty with regard to amounts that may be recovered from other potentially responsible parties.

Derivatives

We use derivative and non-derivative instruments to manage the risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. We also use derivative instruments to engage in propane wholesale marketing activities. We continually monitor the use of these instruments to ensure compliance with our risk management policies and account for them in accordance with appropriate GAAP. If these instruments do not meet the definition of derivatives or are considered normal purchases and sales, they are accounted for on an accrual basis of accounting.

The following is a review of our use of derivative instruments at December 31, 2012 and 2011:

During 2012 and 2011, our natural gas distribution, electric distribution, propane distribution and natural gas marketing operations entered into physical contracts for the purchase or sale of natural gas, electricity and propane. These contracts either did not meet the definition of derivatives as they did not have a minimum requirement to purchase/sell or were considered normal purchases and sales, as they provided for the purchase or sale of natural gas, electricity or propane to be delivered in quantities expected to be used and sold by our operations over a reasonable period of time in the normal course of business. Accordingly, these contracts were accounted for on an accrual basis of accounting.

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During 2012, our propane distribution operation entered into call options to protect against an increase in propane prices associated with the propane purchased for the propane price cap program in December 2012 through March 2013. We accounted for the call options as fair value hedges, and the change in fair value of \$111,000 effectively reduced the propane inventory balance at December 31, 2012.

During 2011, our propane distribution operation entered into a put option to protect against the decline in propane prices and related potential inventory losses associated with the propane purchased for the propane price cap program in the upcoming heating season. We accounted for the put option as a fair value hedge. Since the propane prices fell below the strike price of \$1.445 per gallon in January through March of 2012, we received \$118,000 representing the difference between the market price and the strike price during those months.

Xeron, our propane wholesale marketing subsidiary, enters into forward, futures and other contracts that are considered derivatives. These contracts are marked to market, using prices at the end of each reporting period, and unrealized gains or losses are recorded in the consolidated statements of income as revenue or expense. These contracts generally mature within one year and are almost exclusively for propane commodities. For 2012 and 2011, these contracts had net unrealized losses of \$339,000 and net unrealized gains of \$41,000, respectively. We had \$210,000 in mark-to-market energy assets and \$331,000 in mark-to-market energy liabilities related to these contracts at December 31, 2012. We had \$1.7 million in mark-to-market energy assets and \$1.5 million in mark-to-market energy liabilities related to these contracts at December 31, 2011.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC of each state in which we operate. Eastern Shore's revenues are based on rates approved by the FERC. Customers' base rates may not be changed without formal approval by these commissions. The PSCs, however, have authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to negotiated rates.

For regulated deliveries of natural gas and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class. A similar computation is made to accrue unbilled revenues for propane customers with meters, such as community gas system customers, and natural gas marketing customers, whose billing cycles do not coincide with the accounting periods.

The propane wholesale marketing operation records trading activity for open contracts on a net mark-to-market basis in the statement of income. For propane bulk delivery customers without meters and advanced information services customers, we record revenue in the period the products are delivered and/or services are rendered.

Each of our natural gas distribution operations in Delaware and Maryland, our bundled natural gas distribution service in Florida and our electric distribution operation in Florida has a fuel cost recovery mechanism. This mechanism provides us with a method of adjusting billing rates to customers to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year.

We charge flexible rates to industrial interruptible customers on our natural gas distribution systems to compete with the price of alternative fuel that they can use. Neither we nor any of our interruptible customers are contractually obligated to deliver or receive natural gas on a firm service basis.

Allowance for Doubtful Accounts

An allowance for doubtful accounts is recorded against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect based upon our collections experience, the condition of the overall economy and our assessment of our customers' inability or reluctance to pay. If circumstances change, however, our estimate of the recoverability of accounts receivable may also change. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

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Pension and Other Postretirement Benefits

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. The assumed discount rates and the expected returns on plan assets are the assumptions that generally have the most significant impact on the pension costs and liabilities. The assumed discount rates, the assumed health care cost trend rates and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities. Additional information is presented in Item 8 under the heading "Notes to the Consolidated Financial Statements" Note 15, Employee Benefit Plans, including plan asset investment allocation, estimated future benefit payments, general descriptions of the plans, significant assumptions, the impact of certain changes in assumptions, and significant changes in estimates.

Total pension and other postretirement benefit costs included in operating income were \$599,000, \$1.9 million and \$2.0 million, in 2012, 2011 and 2010, respectively. The total costs for 2012 include a curtailment gain of \$892,000 associated with a plan change for the postretirement medical plan for FPU, effective January 1, 2012, \$170,000 of which was recorded in 2012 and the remaining portion was deferred as a regulatory liability. The total costs for 2011 included \$436,000 of settlement charges associated with the retirement of a former executive. We expect to record pension and postretirement benefit costs of approximately \$999,000 for 2013. Actuarial assumptions affecting 2012 include expected long-term rates of return on plan assets of 6.0 percent and 7.0 percent for Chesapeake's pension plan and FPU's pension plan, respectively, and discount rates of 3.50 percent and 3.75 percent for Chesapeake's and FPU's plans, respectively. The discount rate for each plan was determined by management considering high-quality corporate bond rates, such as Moody's Aa bond index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected lives of the plans and the availability of the lump-sum payment option.

Actual changes in the fair value of plan assets and the differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension and postretirement benefit costs that we ultimately recognize. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately \$11,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately \$13,000. A 0.25 percent change in the rate of return could change our annual pension cost by approximately \$124,000 and would not have an impact on the postretirement and supplemental executive retirement plans because these plans are not funded.

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(d) Results of Operations

(in thousands except per share)

For the Years Ended December 31,	2012	2011	Increase (decrease)	2011	2010	Increase (decrease)
Business Segment:						
Regulated Energy	\$ 46,999	\$ 43,911	\$ 3,088	\$ 43,911	\$ 43,267	\$ 644
Unregulated Energy	8,355	9,619	(1,264)	9,619	8,150	1,469
Other	1,281	175	1,106	175	513	(338)
Operating Income	56,635	53,705	2,930	53,705	51,930	1,775
Other Income	271	906	(635)	906	195	711
Interest Charges	8,747	9,000	(253)	9,000	9,146	(146)
Pre-tax Income	48,159	45,611	2,548	45,611	42,979	2,632
Income Taxes	19,296	17,989	1,307	17,989	16,923	1,066
Net Income	\$ 28,863	\$ 27,622	\$ 1,241	\$ 27,622	\$ 26,056	\$ 1,566
Earnings Per Share of Common Stock						
Basic	\$ 3.01	\$ 2.89	\$ 0.12	\$ 2.89	\$ 2.75	\$ 0.14
Diluted	\$ 2.99	\$ 2.87	\$ 0.12	\$ 2.87	\$ 2.73	\$ 0.14

2012 compared to 2011

Our net income increased by approximately \$1.2 million, or \$0.12 per share (diluted) in 2012, compared to 2011. Key variances include:

(in thousands, except per share amounts)	Pre-tax Income	Net Income	Earnings Per Share
2011 Reported Results	\$ 45,611	\$ 27,622	\$ 2.87
Adjusting for unusual items:			
Weather impact	(3,627)	(2,197)	(0.23)
Amortization of acquisition premium and costs	(2,354)	(1,426)	(0.15)
Severance and pension settlement charge in 2011	1,299	787	0.08
Florida natural gas reserve and sales tax reserve reversal in 2011	(1,049)	(636)	(0.07)
Amortization of deferred tax gain	684	414	0.04
Litigation settlement with a major propane supplier in 2011	(575)	(348)	(0.04)
Gain from the sale of Internet Protocol asset in 2011	(553)	(335)	(0.03)
	(6,175)	(3,741)	(0.40)
Increased Margins:			
Natural gas growth	6,263	3,793	0.40
Higher propane retail margins per gallon	2,724	1,650	0.17
BravePoint	2,602	1,576	0.16
	11,589	7,019	0.73
Increased Other Operating Expenses:			
BravePoint, primarily due to employee-related costs	(1,523)	(923)	(0.10)
Higher depreciation, asset removal and facilities costs	(1,326)	(803)	(0.08)
Acquisition-related costs and increased capacity for future growth	(758)	(459)	(0.05)
	(3,607)	(2,185)	(0.23)

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Net other changes	741	148	0.02
2012 Reported Results	\$ 48,159	\$ 28,863	\$ 2.99

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Our results for 2012 reflected additional gross margin generated by: (a) the natural gas transmission and distribution operations as a result of major expansion initiatives in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Nassau County, Florida; (b) additional customer growth; and (c) additional transmission services provided to an existing industrial customer. Higher retail propane margins per gallon, as a result of sustained retail prices and favorable supply costs, and increased product sales and consulting activities from BravePoint also generated additional gross margin. These increases in gross margin more than offset a reduction of \$3.6 million in gross margin due to significantly warmer temperatures in 2012, particularly during the first three months of the year. Also included in the 2012 results is the amortization expense of \$2.4 million related to the recovery of the FPU acquisition adjustment and merger-related costs, partially offset by an amortization credit of \$684,000 associated with FPU's pre-merger deferred income tax gain. Higher expenses associated with growth initiatives and capital investments to support growth and system integrity also offset the gross margin increases.

2011 compared to 2010

Our net income increased by approximately \$1.6 million, or \$0.14 per share (diluted) in 2011, compared to 2010. Key variances include:

(in thousands, except per share amounts)	Pre-tax Income	Net Income	Earnings Per Share
2010 Reported Results	\$ 42,979	\$ 26,056	\$ 2.73
Adjusting for unusual items:			
Lower energy consumption, due primarily to weather	(5,233)	(3,168)	(0.33)
Florida regulatory reserve recorded in 2010 and reversed in 2011	1,500	921	0.10
Severance and pension settlement charge in 2011	(1,284)	(777)	(0.08)
Sales tax reserves recorded in 2010 and reversed in 2011	959	589	0.06
Absence of merger-related costs in 2011	660	395	0.04
Litigation settlement with a major propane supplier in 2011	575	342	0.04
Gain from the sale of Internet Protocol asset in 2011	553	331	0.03
	(2,270)	(1,367)	(0.14)
Increased Margins:			
New natural gas transportation services	2,914	1,702	0.17
Growth in natural gas distribution customers	2,362	1,419	0.15
Higher propane retail margins per gallon	2,248	1,381	0.14
	7,524	4,502	0.46
Increased Other Operating Expenses:			
Increased depreciation and asset removal costs from regulated assets	(1,232)	(732)	(0.08)
BravePoint's decline in operating income due to a new product launch	(858)	(527)	(0.05)
Increased vehicle fuel costs	(621)	(376)	(0.04)
Additional legal costs as a result of an electric franchise dispute	(537)	(330)	(0.03)
	(3,248)	(1,965)	(0.20)
Net other changes	626	396	0.02
2011 Reported Results	\$ 45,611	\$ 27,622	\$ 2.87

Our results for 2011 reflected additional gross margin generated by: (a) new services initiated by the natural gas transmission operation; (b) customer growth in the natural gas distribution operations; and (c) higher retail propane margins per gallon, as a result of unusually low retail margins per gallon in 2010 due to high spot purchases to meet the high customer demands in the cold winter. These increases in gross margin more than offset a reduction of \$5.2 million in gross margin as a result of lower customer energy consumption due primarily to significantly warmer temperatures in 2011, compared to 2010. During 2011, we recorded \$1.3 million in non-recurring charges related to severance and pension settlements. Also included in the 2011 results are the impact of reversing the Florida regulatory reserve and sales tax reserve, both of which were recorded in 2010, and one-time gains related to proceeds from a litigation settlement with a major supplier and sale of a non-operating asset. BravePoint's operating income declined by \$858,000 in 2011, compared to 2010, as a result of the launch of ProfitZoom™. We also incurred additional legal costs of \$537,000 as a result of an electric franchise dispute.

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

Regulated Energy

For the Years Ended December 31, (in thousands)	2012	2011	Increase (decrease)	2011	2010	Increase (decrease)
Revenue	\$ 246,208	\$ 256,226	(\$10,018)	\$ 256,226	\$ 269,438	(\$13,212)
Cost of sales	111,402	128,111	(16,709)	128,111	145,207	(17,096)
Gross margin	134,806	128,115	6,691	128,115	124,231	3,884
Operations & maintenance	61,113	59,816	1,297	59,816	57,464	2,352
Depreciation & amortization	18,653	16,512	2,141	16,512	14,680	1,832
Other taxes	8,041	7,876	165	7,876	8,820	(944)
Other operating expenses	87,807	84,204	3,603	84,204	80,964	3,240
Operating Income	\$ 46,999	\$ 43,911	\$ 3,088	\$ 43,911	\$ 43,267	\$ 644

Weather and Customer Analysis

For the Years Ended December 31, Delmarva Peninsula	2012	2011	Increase (decrease)	2011	2010	Increase (decrease)
Actual HDD	3,936	4,221	(285)	4,221	4,831	(610)
10-year average HDD	4,491	4,499	(8)	4,499	4,528	(29)
Estimated gross margin per HDD	\$ 1,712	\$ 2,064	(\$352)	\$ 2,064	\$ 1,995	\$ 69
Per residential customer added:						
Estimated gross margin	\$ 375	\$ 375	\$ 0	\$ 375	\$ 375	\$ 0
Estimated other operating expenses	\$ 113	\$ 111	\$ 2	\$ 111	\$ 105	\$ 6

Florida

Actual HDD	633	753	(120)	753	1,501	(748)
10-year average HDD	915	920	(5)	920	863	57
Actual CDD	2,871	2,858	13	2,858	2,859	(1)
10-year average CDD	2,756	2,718	38	2,718	2,695	23

Average number of residential customers

Delmarva natural gas distribution	49,639	48,680	959	48,680	47,638	1,042
Florida natural gas distribution	62,386	61,525	861	61,525	61,053	472
Florida electric distribution	23,670	23,598	72	23,598	23,589	9
Total	135,695	133,803	1,892	133,803	132,280	1,523

2012 Compared to 2011

Operating income for our regulated energy segment for 2012 was \$47.0 million, an increase of \$3.1 million, or seven percent, compared to 2011. An increase in gross margin of \$6.7 million was partially offset by an increase in other operating expenses of \$3.6 million.

Table of ContentsGross Margin

Gross margin for our regulated energy segment increased by \$6.7 million, or five percent, in 2012, compared to 2011. Items contributing to the year-over-year increase in gross margin are listed in the following table:

<i>(in thousands)</i>	
Gross margin for the year ended December 31, 2011	\$ 128,115
Factors contributing to the gross margin increase for the year ended December 31, 2012:	
Major expansion initiatives	3,475
Other customer growth natural gas distribution	2,073
Florida natural gas regulatory reserve	(750)
Eastern Shore rate case settlement	737
Other new services natural gas transmission	713
Decreased customer consumption weather and other	(230)
Other	673
Gross margin for the year ended December 31, 2012	\$ 134,806

Major Expansion Initiatives

Major expansion initiatives in Sussex County, Delaware; Worcester and Cecil Counties, Maryland; and Nassau County, Florida generated \$3.5 million in additional gross margin in 2012, compared to 2011. In Sussex County, Delaware, Eastern Shore initiated new transmission service and our Delmarva natural gas distribution operation initiated distribution service to two large industrial customers in Lewes, Delaware during the fourth quarter of 2011. These services generated \$779,000 and \$499,000, respectively, of additional gross margin in 2012. Eastern Shore also began new transmission service and our Delmarva natural gas distribution operation initiated distribution service to two industrial facilities of an existing customer in southeast Sussex County, Delaware generating \$334,000 and \$89,000, respectively, of additional gross margin during 2012. Eastern Shore also generated \$90,000 in additional transmission gross margin as a result of the Worcester County, Maryland expansion, and Eastern Shore commenced additional transmission service in Worcester County, Maryland during the first quarter of 2013. The Cecil County, Maryland expansion commenced during the fourth quarter of 2012 and generated \$147,000 of additional transmission gross margin. The Nassau County, Florida expansion generated \$1.5 million in additional transmission gross margin for Peninsula Pipeline.

Other Customer Growth Natural Gas Distribution

The Florida natural gas distribution operation generated \$986,000 of additional gross margin due primarily to a three-percent growth in commercial and industrial customers.

The Delmarva natural gas distribution operation generated \$1.1 million of additional gross margin in 2012, compared to 2011, due primarily to the addition of 12 new large commercial and industrial customers since the beginning of 2011 and two-percent growth in residential customers.

Florida Natural Gas Regulatory Reserve

In January 2012, the Florida PSC issued an order approving the recovery of \$34.2 million as an acquisition adjustment and \$2.2 million in merger-related costs in connection with the Company's acquisition of FPU in 2009. In the order, the Florida PSC also determined that no refund should be made to customers as a result of the 2010 earnings of our Florida natural gas distribution operations. Pursuant to this order, in the fourth quarter of 2011, we reversed the \$750,000 reserve, which was accrued in the third and fourth quarters of 2010 based on the contingent regulatory risks associated with the Florida natural gas earnings, merger benefits and recovery of the acquisition adjustment.

Eastern Shore Rate Case Settlement

Eastern Shore generated \$737,000 of additional gross margin in 2012, compared to 2011, as a result of new rates that became effective July 2011.

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Other New Services Natural Gas Transmission

Eastern Shore generated additional gross margin of \$713,000 in 2012, due primarily to a new transmission service agreement for an additional 9,514 Dts/d with an existing industrial customer for the period from November 2011 to October 2012.

Decreased Customer Consumption Weather and Other

Customer consumption of natural gas and electricity decreased, primarily on the Delmarva Peninsula, during 2012, compared to 2011. Consumption of energy is normally highest during the first and fourth quarters due to colder temperatures. The first quarter of 2012 was the warmest first quarter in the past 10 years, both on the Delmarva Peninsula and in Florida. We estimate that significantly warmer weather in 2012, primarily during the first three months of 2012, resulted in a period-over-period decrease of approximately \$926,000 in gross margin, most of which occurred during the first three months of the year. This decrease was partially offset by \$696,000 in higher gross margins due primarily to other volume increases in Florida.

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Table of Contents**Other Operating Expenses**

Other operating expenses for the regulated energy segment increased by \$3.6 million for 2012 due largely to: (a) \$2.4 million in increased amortization expense associated with the recovery of the FPU acquisition adjustment and merger-related costs, which was partially offset by an amortization credit of \$684,000 associated with FPU's pre-merger deferred income tax gain; (b) \$1.3 million in higher depreciation expense, asset removal and facilities costs associated with capital investments; (c) \$646,000 in increased costs associated with investing in growth; (d) \$379,000 in increased payroll and benefits cost for the Delmarva natural gas distribution operation due to increased staffing to support expansions; (e) \$325,000 in increased costs related to pipeline integrity requirements; (f) \$305,000 in higher legal costs associated with an electric franchise dispute in Marianna, Florida; and (g) \$254,000 in an increased accrual for general liability claim. These increases in expenses were partially offset by \$1.2 million in reduced payroll and benefits, primarily in Florida, because of a workforce reduction in 2011, and one-time charges totaling \$1.1 million in 2011 as a result of the voluntary workforce reduction in Florida and pension settlements.

2011 Compared to 2010

Operating income for our regulated energy segment increased by approximately \$644,000, or one percent, in 2011, compared to 2010, which was generated from a gross margin increase of \$3.9 million, offset by an other operating expense increase of \$3.2 million.

Gross Margin

Gross margin for our regulated energy segment increased by \$3.9 million, or three percent, in 2011, compared to 2010. Items contributing to the year-over-year increase in gross margin are listed in the following table:

(in thousands)

Gross margin for the year ended December 31, 2010	\$ 124,231
Factors contributing to the gross margin increase for the year ended December 31, 2011:	
Decreased customer consumption, due primarily to weather	(3,753)
New transportation services	2,914
Net customer growth in distribution services	2,739
Florida natural gas regulatory reserve	1,500
Change in rates	409
Other	75
Gross margin for the year ended December 31, 2011	\$ 128,115

Decreased Customer Consumption, Due Primarily to Weather

Customer consumption of natural gas and electricity decreased, both on the Delmarva Peninsula and in Florida, during 2011, compared to 2010. The decline in consumption was due primarily to significantly warmer weather during the heating season, resulting in a year-over-year decrease of approximately \$3.8 million in gross margin. In 2011, HDD decreased by 13 percent, or 610 HDD, on the Delmarva Peninsula and by 50 percent, or 748 HDD, in Florida, compared to 2010. Measured against normal HDD (10-year historical average) in 2011, the weather on the Delmarva Peninsula was six percent, or 278 HDD, warmer than normal, and the weather in Florida was 18 percent, or 167 HDD, warmer than normal. We estimate that this warmer-than-normal weather reduced gross margin of the regulated energy segment by approximately \$2.1 million in 2011.

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New Transportation Services

In January 2011, Eastern Shore commenced new transportation service for 20,000 Dts/d of capacity associated with its eight-mile mainline extension to interconnect with TETLP's pipeline system, which generated gross margin of \$2.0 million in 2011.

Other additional transportation services that commenced in May 2010, November 2010 and November 2011, as a result of Eastern Shore's system expansion projects, generated additional gross margin of \$542,000 in 2011.

Eastern Shore entered into two additional transportation services agreements with an existing industrial customer, one for the period from May 2011 to April 2021 for an additional 3,405 Dts/d and the second for the period from November 2011 to October 2012 for an additional 9,514 Dts/d. These additional services generated additional gross margin of \$243,000 and \$168,000, respectively, in 2011.

Partially offsetting these gross margin increases was a gross margin decrease of \$66,000 due to the expiration in April 2010 of two transportation service contracts.

Net Customer Growth in Distribution Services

The Delmarva natural gas distribution operation generated \$1.6 million of additional gross margin due to net customer growth. Gross margin from commercial and industrial customers for the Delmarva natural gas distribution operation increased by \$1.2 million in 2011, due primarily to the addition of 20 large commercial and industrial customers since June 2010. Two-percent growth in residential customers generated an additional \$429,000 of gross margin for the Delmarva natural gas distribution operation.

The Florida natural gas distribution operations generated \$771,000 of additional gross margin primarily as a result of a two-percent growth in commercial and industrial customers. In addition, 700 new customers, added as a result of our purchase of the operating assets of Indiantown Gas Company (IGC) in August 2010, generated \$377,000 of additional gross margin during 2011 due to the inclusion of a full year of results.

Florida Natural Gas Regulatory Reserve

In January 2012, the Florida PSC issued an order, approving the recovery of \$34.2 million as an acquisition adjustment and \$2.2 million in merger-related costs in connection with our acquisition of FPU in 2009. In the order, the Florida PSC also determined that no refund should be made to customers as a result of the 2010 earnings of our Florida natural gas distribution operations. Pursuant to this order, in the fourth quarter of 2011, we reversed the \$750,000 reserve, which was accrued in the third and fourth quarters of 2010 based on the contingent regulatory risks associated with the Florida natural gas earnings, merger benefits and recovery of the acquisition adjustment.

Change in Rates

On January 24, 2012, the FERC approved a rate case settlement for Eastern Shore. In 2011, we recorded \$409,000 of additional gross margin as a result of implementing the new rates pursuant to the settlement.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by \$3.2 million for 2011 due largely to the following factors: (a) \$1.2 million in higher depreciation expense and asset removal costs associated with capital investments; (b) \$1.1 million in non-recurring severance and pension settlement charges; (c) \$537,000 in increased legal costs associated with the electric franchise dispute in Marianna, Florida; (d) \$403,000 in additional expenses related to pipeline integrity projects for Eastern Shore to comply with increased pipeline regulatory requirements; (e) \$375,000 in increased amortization expense related to the change in the recovery period of certain specific project costs; (f) \$355,000 in higher vehicle fuel costs; and (g) \$896,000 in lower taxes other than income taxes, due to an accrual in 2010 for potential additional sales taxes and gross receipts taxes and the reversal of a portion of the accrual in 2011 as a result of the collection and remittance of those taxes.

Table of Contents**Unregulated Energy**

For the Years Ended December 31, (in thousands)	2012	2011	Increase (decrease)	2011	2010	Increase (decrease)
Revenue	\$ 133,049	\$ 149,586	(\$16,537)	\$ 149,586	\$ 146,793	\$ 2,793
Cost of sales	97,137	112,415	(15,278)	112,415	110,679	1,736
Gross margin	35,912	37,171	(1,259)	37,171	36,114	1,057
Operations & maintenance	22,804	22,863	(59)	22,863	22,751	112
Depreciation & amortization	3,420	3,229	191	3,229	3,569	(340)
Other taxes	1,333	1,460	(127)	1,460	1,644	(184)
Other operating expenses	27,557	27,552	5	27,552	27,964	(412)
Operating Income	\$ 8,355	\$ 9,619	(\$1,264)	\$ 9,619	\$ 8,150	\$ 1,469

Weather Analysis Delmarva

For the Years Ended December 31,	2012	2011	Increase (decrease)	2011	2010	Increase (decrease)
Actual HDD	3,936	4,221	(285)	4,221	4,831	(610)
10-year average HDD	4,491	4,499	(8)	4,499	4,528	(29)
Estimated gross margin per HDD	\$ 2,882	\$ 2,869	\$ 13	\$ 2,869	\$ 2,611	\$ 258

2012 Compared to 2011

Operating income for our unregulated energy segment for 2012 was \$8.4 million, a decrease of \$1.3 million, or 13 percent, compared to 2011, due primarily to a decrease in gross margin of \$1.3 million. Other operating expenses for 2012 remained unchanged from 2011.

Gross Margin

Gross margin for our unregulated energy segment decreased by \$1.3 million, or three percent, in 2012, compared to 2011. Items contributing to the year-over-year decrease in gross margin are listed in the following table:

(in thousands)

Gross margin for the year ended December 31, 2011	\$ 37,171
Factors contributing to the gross margin decrease for the year ended December 31, 2012:	
Decreased customer consumption weather and other	(3,259)
Increase in retail margins per gallon	2,724
Gain from litigation settlement recorded in 2011	(575)
Other	(149)
Gross margin for the year ended December 31, 2012	\$ 35,912

Decreased Customer Consumption Weather and Other

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Significantly warmer weather, particularly during the first three months of 2012 when propane demand for heating is typically at its highest, resulted in decreased gross margin of \$2.7 million in 2012, compared to 2011. Additionally, both our Delmarva and Florida propane distribution operations experienced a decline in sales volume beyond the estimated weather impact in 2012, compared to 2011, due to the timing of deliveries to bulk-delivery customers, conservation and other factors. This additional decline in sales volume was partially offset by additional gross margin generated from 1,180 customers acquired in late 2011 and early 2012, following the purchase of the operating assets of several small propane distribution companies in Florida. These factors resulted in a net decrease in propane gross margin of \$515,000 in 2012, compared to 2011.

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Table of Contents*Increase in Retail Margins per Gallon*

Higher retail margins per gallon in the Delmarva and Florida propane distribution operation generated \$631,000 and \$2.1 million, respectively, of additional gross margin in 2012, compared to 2011. Sustained retail pricing in response to local market conditions and lower average propane inventory cost contributed to the higher retail margins per gallon.

Gain from Litigation Settlement Recorded in 2011

A non-recurring gain of \$575,000 was recorded in 2011 related to our share of proceeds received from an antitrust litigation settlement with a major propane supplier and is reflected as a period-over-period decrease in gross margin.

Other

PESCO's gross margin decreased by \$310,000 in 2012, compared to 2011. PESCO's gross margin in 2011 benefited from unusually large favorable imbalance resolutions with third-party intrastate pipelines, with which PESCO contracts for supply. Imbalance resolutions are not predictable and, therefore, are not included in our long-term financial plans or forecasts. Lower gross margin from imbalance resolutions was partially offset by additional gross margin generated by new customers and contracts.

Partially offsetting the decrease in PESCO's gross margin was the increase in gross margin of Xeron, which increased by \$225,000 in 2012, compared to 2011, as a result of higher margins from its trading activity. Xeron executed trades with higher margins in 2012 as the market presented opportunities from fluctuations in wholesale propane prices.

Other Operating Expenses

Other operating expenses for the unregulated energy segment were \$27.6 million for both 2012 and 2011.

2011 Compared to 2010

Operating income for our unregulated energy segment increased by approximately \$1.5 million, or 18 percent, in 2011 compared to 2010, which was attributable to an increase in gross margin of \$1.1 million and a decrease in other operating expenses of \$412,000.

Gross Margin

Gross margin for our unregulated energy segment increased by \$1.1 million, or three percent in 2011 compared to 2010. Items contributing to the year-over-year decrease in gross margin are listed in the following table:

(in thousands)

Gross margin for the year ended December 31, 2010	\$ 36,114
Factors contributing to the gross margin increase for the year ended December 31, 2011:	
Volume decrease weather and other	(2,759)
Increase in retail margin per gallon	2,248
Gain from litigation settlement	575
Propane wholesale marketing	431
Natural gas marketing	362
Miscellaneous fees and other	200
Gross margin for the year ended December 31, 2011	\$ 37,171

Volume Decrease Weather and Other

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A decline in customer consumption, due primarily to a decrease in HDD, resulted in decreased gross margin of \$1.5 million in 2011, compared to 2010, for the Delmarva propane distribution operation. A decrease in propane deliveries to bulk customers, due to lower non-weather-related consumption and the timing of deliveries, also decreased gross margin by \$1.3 million.

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Table of Contents*Increase in Retail Margin per Gallon*

The propane distribution operations generated additional gross margin of \$2.2 million due to higher margins per gallon for 2011, compared to 2010. Propane retail margins per gallon on the Delmarva Peninsula during 2011 returned to more normal levels, compared to retail margins per gallon during 2010. The lower margins in 2010 were caused by colder temperatures and higher cost spot purchases during the first quarter when customer demand was the highest. Also contributing to the gross margin increase were higher margins per gallon in Florida as the propane distribution operation continued to adjust its retail pricing in response to market conditions.

Gain from Litigation Settlement

We recorded a one-time gain of \$575,000 in the first quarter of 2011 related to our share of proceeds received from an antitrust litigation settlement with a major propane supplier.

Propane Wholesale Marketing

Xeron generated \$431,000 of additional gross margin in 2011, compared to 2010, due primarily to a 22-percent increase in trading activity.

Natural Gas Marketing

PESCO generated higher gross margin of \$362,000 in 2011, compared to 2010. Favorable imbalance resolutions with third-party pipelines, with which PESCO contracts for natural gas supply, generated this increase. Such imbalance resolutions are not predictable and therefore, are not included in our long-term financial plans or forecasts.

Other Operating Expenses

Other operating expenses for the unregulated energy segment decreased by \$412,000 in 2011, compared to 2010. In 2010, we expensed \$370,000 related to the settlement of a propane class action litigation and recorded \$351,000 in amortization expense associated with the favorable propane supply contracts acquired in the merger with FPU, which was recorded as an intangible asset. The absence of these expenses in 2011 resulted in a decrease in other operating expenses in 2011, compared to 2010. These decreases were partially offset by a \$265,000 increase in vehicle fuel costs in 2011.

Other

For the Years Ended December 31, (in thousands)	2012	2011	Increase (decrease)	2011	2010	Increase (decrease)
Revenue	\$ 18,357	\$ 13,829	\$ 4,528	\$ 13,829	\$ 13,142	\$ 687
Cost of sales	8,872	7,051	1,821	7,051	6,316	735
Gross margin	9,485	6,778	2,707	6,778	6,826	(48)
Operations & maintenance	6,953	5,515	1,438	5,515	5,426	89
Depreciation & amortization	438	413	25	413	289	124
Other taxes	814	676	138	676	600	76
Other operating expenses	8,205	6,604	1,601	6,604	6,315	289
Operating Income Other	1,280	174	1,106	174	511	(337)
Operating Income Eliminations	1	1		1	2	(1)
Operating Income	\$ 1,281	\$ 175	\$ 1,106	\$ 175	\$ 513	(\$338)

2012 Compared to 2011

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Operating income for our Other segment for 2012 was \$1.3 million, an increase of \$1.1 million, compared to 2011. The increase was attributable to higher operating income from BravePoint.

BravePoint, which reported operating income of \$828,000 in 2012, compared to an operating loss of \$270,000 for 2011, generated increased gross margin of \$2.6 million, \$852,000 of which represents increased margin from ProfitZoom and Application Evolution sales and related services. The remaining increase in gross margin was generated from higher consulting revenues and other product sales. This increase in gross margin was partially offset by \$1.5 million of increased other operating expenses as a result of resources added to support these services.

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2011 Compared to 2010

Operating income for our Other segment for 2011 was \$175,000, representing a decrease of \$338,000 from operating income of \$513,000 for 2010. The decrease was attributable to lower operating income of \$1.0 million from BravePoint, offset partially by the absence in 2011 of \$660,000 in merger-related costs expensed in 2010.

BravePoint reported an operating loss of \$270,000 in 2011, compared to operating income of \$759,000 in 2010. During 2011, BravePoint incurred \$1.1 million in additional costs associated with the product development and release of ProfitZoom™. BravePoint recorded \$572,000 in revenue in 2011 from these new contracts.

Other Income

Other income for 2012, 2011 and 2010 was \$271,000, \$906,000 and \$195,000, respectively. Included in other income for 2011 was a \$553,000 gain from the sale of a non-operating Internet Protocol address asset. The remaining balance in other income includes non-operating investment income, interest income, late fees charged to customers and gains or losses from the sale of assets.

Interest Expense

2012 Compared to 2011

Total interest expense for 2012 decreased by approximately \$253,000, or three percent, compared to 2011. The decrease in interest expense is attributable primarily to decreases of \$699,000 in other long-term interest expense due to scheduled repayments and \$337,000 in interest on deposits from FPU's customers due to a lower interest rate on those deposits. Additionally contributing to the decrease, is a reduction of \$41,000 in short-term interest expense due to slightly lower borrowings and rates in 2012, compared to 2011. Offsetting the decrease in interest expense was additional interest expense of \$824,000 related to the \$29 million long-term debt issuance of 5.68 percent unsecured senior notes on June 23, 2011. We used the proceeds from these notes to repay a portion of Chesapeake's short-term loan credit facilities, which had been used to redeem two series of FPU first mortgage bonds.

2011 Compared to 2010

Total interest expense for 2011 decreased by \$146,000, or two percent, compared to 2010. The decrease in interest expense is attributable primarily to a decrease of \$651,000 in long-term interest expense as scheduled repayments decreased the outstanding principal balances. Offsetting this decrease was additional interest expense of \$505,000 related to the \$29 million long-term debt issuance of 5.68 percent unsecured senior notes on June 23, 2011. We used the proceeds to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU first mortgage bonds. These redemptions occurred in January 2010 and were previously financed by Chesapeake's short-term loan facilities.

Income Taxes

2012 Compared to 2011

Income tax expense was \$19.3 million in 2012, compared to \$18.0 million in 2011. Our effective tax rate was 40.1 percent in 2012, compared to 39.4 percent in 2011. The increase in our effective tax rate in 2012 is due primarily to a \$300,000 tax contingency accrual associated with a state tax audit recorded during 2012.

2011 Compared to 2010

Income tax expense was \$18.0 million in 2011, compared to \$16.9 million in 2010. Our effective income tax rate for 2011 and 2010 remained unchanged at 39.4 percent.

Table of Contents**(e) Liquidity and Capital Resources**

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

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

Capital expenditures, which are our investments in new or acquired plant and equipment, are our largest capital requirements. Our capital expenditures during 2012, 2011 and 2010 were \$78.2 million, \$44.4 million and \$47.0 million, respectively. We experienced a significant increase in our capital expenditures in 2012, compared to 2011 and 2010, as a result of continued expansions of our natural gas distribution and transmission systems on the Delmarva Peninsula and in Florida as well as a natural gas infrastructure replacement program in Florida, electric infrastructure improvements in Florida to increase the distribution system reliability, and various customer billing system and other initiatives.

We have budgeted \$112.3 million for capital expenditures during 2013. The following table shows the 2013 capital expenditure budget by segment:

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

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

In addition, we recently entered into an agreement with ESG to purchase its propane distribution assets that serve approximately 11,000 residential and commercial customers in Worcester County, Maryland, primarily through underground propane gas distribution systems. The purchase price is approximately \$16.5 million, which is subject to certain adjustments as specified in the agreement. We expect to finance the purchase of these assets using unsecured short-term debt. The transaction is expected to be completed in 2013.

Table of Contents**Capital Structure**

We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors. The following presents our capitalization, excluding and including short-term borrowings, as of December 31, 2012 and 2011:

	December 31, 2012		December 31, 2011	
<i>(in thousands)</i>				
Long-term debt, net of current maturities	\$ 101,907	28%	\$ 110,285	31%
Stockholders' equity	256,598	72%	240,780	69%
Total capitalization, excluding short-term debt	\$ 358,505	100%	\$ 351,065	100%

	December 31, 2012		December 31, 2011	
<i>(in thousands)</i>				
Short-term debt	\$ 61,199	14%	\$ 34,707	9%
Long-term debt, including current maturities	110,103	26%	118,481	30%
Stockholders' equity	256,598	60%	240,780	61%
Total capitalization, including short-term debt	\$ 427,900	100%	\$ 393,968	100%

As of December 31, 2012, we did not have any restrictions on our cash balances. Both Chesapeake's senior notes and FPU's first mortgage bonds contain a restriction that limits the payment of dividends or other restricted payments in excess of certain pre-determined thresholds. As of December 31, 2012, \$82.3 million of Chesapeake's cumulative consolidated net income and \$47.5 million of FPU's cumulative net income were free of such restrictions.

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Short-term Borrowings

Our outstanding short-term borrowings at December 31, 2012 and 2011 were \$61.2 million and \$34.7 million, respectively, at the weighted average interest rates of 1.48 percent and 1.53 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. As of December 31, 2012, we had four unsecured bank lines of credit with two financial institutions for a total of \$100.0 million. Two of these unsecured bank lines, totaling \$60.0 million, are available under committed lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to \$100.0 million of short-term debt, as required, from these unsecured bank lines of credit.

In addition to the four unsecured bank lines of credit, we entered into a new, unsecured short-term credit facility for \$40 million with an existing lender on June 22, 2012. Short-term borrowings under this new facility bear interest at LIBOR plus 80 basis points or, at our discretion, the lender's base rate plus 80 basis points. This facility, which is structured in the form of a revolving credit note, matures on October 31, 2013.

Our outstanding borrowings under these unsecured bank lines of credit at December 31, 2012 and 2011 were \$56.4 million and \$30.5 million, respectively. During 2012, 2011 and 2010, the average borrowings from these unsecured bank lines of credit were \$23.4 million, \$11.0 million and \$10.5 million, respectively, at weighted average interest rates of 1.79 percent, 2.35 percent and 2.40 percent, respectively. The maximum month-end borrowings from these unsecured bank lines of credit during 2012, 2011 and 2010 were \$56.4 million, \$35.4 million and \$64.0 million, respectively, which occurred during the fall and winter months when our working capital requirements were at the highest level. Also included in our outstanding short-term borrowings at December 31, 2012 and 2011 were \$4.8 million and \$4.2 million, respectively, in book overdrafts, which if presented would be funded through the bank lines of credit.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the years ended December 31, 2012, 2011 and 2010:

For the Years Ended December 31, <i>(in thousands)</i>	2012	2011	2010
Net cash provided by (used in):			
Operating activities	\$ 65,872	\$ 71,121	\$ 61,118
Investing activities	(69,829)	(47,836)	(48,922)
Financing activities	4,681	(22,291)	(13,371)
Net increase (decrease) in cash and cash equivalents	724	994	(1,175)
Cash and cash equivalents beginning of period	2,637	1,643	2,818
Cash and cash equivalents end of period	\$ 3,361	\$2,637	\$ 1,643

Cash Flows Provided by Operating Activities

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

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

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In 2012, our net cash flow provided by operating activities was \$65.9 million, a decrease of \$5.2 million, compared to 2011. The decrease was due primarily to the following:

Net cash flows from customer deposits decreased by \$6.7 million due primarily to the absence in 2012 of a large deposit made by an industrial customer in 2011. During 2012, we refunded approximately \$1.3 million of the deposit to this customer.

Net cash flows from the changes in regulatory assets and liabilities decreased by approximately \$2.5 million, primarily as a result of a reduction in fuel costs due and collected from regulated customers.

Net cash flows from propane inventory, storage gas and other inventory increased by \$3.1 million as a result of lower commodity prices. An increase in the pipes and other construction inventory purchased during 2012 offset this increase.

In 2011, our net cash flow provided by operating activities was \$71.1 million, an increase of \$10.0 million, compared to 2010. The increase was due primarily to the following:

Net cash flows related to income taxes, which include deferred income taxes in non-cash adjustments to net income and the change in income taxes receivable, increased by \$7.6 million during 2011, compared to 2010, due primarily to the 100-percent bonus depreciation deduction allowed in 2011, which reduced our income tax payments in 2011.

Net cash flows from trading receivables and payables increased by \$6.0 million, due primarily to the timing of collections and payments of trading contracts entered into by our propane wholesale marketing operation and an increase in net cash flows from receivables and payables in various other operations.

Net cash flows from customer deposits increased by \$3.1 million, due primarily to a large deposit received in 2011 from an industrial customer on the Delmarva Peninsula.

Net cash flows from propane inventory, storage gas and other inventory decreased by \$2.6 million, due primarily to additional pipes and other construction inventory purchased during 2011. Also contributing to this cash flow decrease is the period-over-period changes in the storage gas balance, which reduced our cash flows.

Net cash flows from the changes in regulatory assets and liabilities decreased by approximately \$4.9 million, primarily as a result of a reduction in fuel costs due and collected from regulated customers.

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Cash Flows Used in Investing Activities

In 2012, net cash flows used in investing activities totaled \$69.8 million, representing an increase of \$22.0 million, compared to 2011. In 2011, net cash flows used by investing activities totaled \$47.8 million, a decrease of \$1.1 million, compared to 2010.

Cash utilized for capital expenditures was \$72.0 million, \$47.0 million and \$45.6 million for 2012, 2011, and 2010, respectively.

In 2012, we received \$630,000 from the sale of equity securities and we paid \$124,000 to acquire certain Florida propane assets. In 2011, we invested \$300,000 in equity securities and paid \$790,000 to acquire certain Florida propane assets. In 2010, we invested \$1.6 million in equity securities and paid \$1.2 million and \$310,000 for certain natural gas distribution assets in Florida and propane distribution assets in Virginia.

Environmental expenditures exceeded amounts recovered through rates charged to customers in 2012, 2011 and 2010 by \$607,000, \$645,000 and \$290,000, respectively.

In 2012, we received \$2.2 million from the sale of FPU's office building in West Palm Beach, Florida. In 2011, we received \$553,000 in connection with the sale of a non-operating Internet Protocol address asset.

Cash Flows Provided by/Used in Financing Activities

In 2012, net cash flows provided by financing activities totaled \$4.7 million compared to net cash flows used by financing activities in 2011 and 2010, of \$22.3 million and \$13.4 million, respectively. Significant financing activities included the following:

We repaid \$8.2 million, \$9.1 million and \$36.9 million of long-term debt in 2012, 2011 and 2010, respectively. Included in the long-term debt repayment during 2010 was the redemption of the 6.85 percent and 4.90 percent series of FPU's secured first mortgage bonds prior to their respective maturities by using the proceeds from a new short-term credit facility with an existing lender. During 2011, we issued \$29.0 million of Chesapeake's 5.68 percent unsecured senior notes and used the proceeds to repay the new short-term credit facility and permanently finance the redemption of the FPU bonds.

During 2012 and 2010, we increased our short-term borrowing by \$25.9 million and \$1.6 million, respectively. In 2011 we reduced our short-term borrowing by \$241,000.

We paid \$12.3 million, \$11.7 million and \$11.0 million in cash dividends in 2012, 2011 and 2010, respectively. The increase in cash dividends paid in each year reflects the growth in the annualized dividend rate and increases in the number of shares outstanding in each of the three years.

Table of Contents**Contractual Obligations**

We have the following contractual obligations and other commercial commitments as of December 31, 2012:

Contractual Obligations (in thousands)	Payments Due by Period					Total
	Less than 1 year	1 3 years	3 5 years	5 years	More than 5 years	
Long-term debt ⁽¹⁾	\$ 8,196	\$ 21,280	\$ 21,173	\$ 59,510	\$ 110,159	
Operating leases ⁽²⁾	1,202	1,961	1,214	3,130	7,507	
Purchase obligations ⁽³⁾						
Transmission capacity	26,038	66,936	48,398	150,531	291,903	
Storage Natural Gas	2,189	3,192	2,134	2,290	9,805	
Commodities	25,195	166			25,361	
Electric supply	13,647	29,043	31,499	27,355	101,544	
Forward purchase contracts Propane ⁽⁴⁾	2,460				2,460	
Unfunded benefits ⁽⁵⁾	466	932	857	3,409	5,664	
Funded benefits ⁽⁶⁾	1,080	132	2	1,915	3,129	
Total Contractual Obligations	\$ 80,473	\$ 123,642	\$ 105,277	\$ 248,140	\$ 557,532	

- (1) Principal payments on long-term debt, see Item 8 under the heading Notes to the Consolidated Financial Statements Note 12, Long-Term Debt, for additional discussion of this item. The expected interest payments on long-term debt are \$7.0 million, \$11.9 million, \$9.1 million and \$14.1 million, respectively, for the periods indicated above. Expected interest payments for all periods total \$42.1 million.
- (2) See Item 8 under the heading Notes to the Consolidated Financial Statements Note 14, Lease Obligations, for additional discussion of this item.
- (3) See Item 8 under the heading Notes to the Consolidated Financial Statements Note 19, Other Commitments and Contingencies, for further information.
- (4) The Company has also entered into forward sale contracts. See Market Risk of the Management's Discussion and Analysis for further information.
- (5) We have recorded long-term liabilities of \$5.7 million at December 31, 2012 for unfunded post-employment and post-retirement benefit plans. The amounts specified in the table are based on expected payments to current retirees and assumes a retirement age of 62 for currently active employees. There are many factors that would cause actual payments to differ from these amounts, including early retirement, future health care costs that differ from past experience and discount rates implicit in calculations.
- (6) We have recorded long-term liabilities of \$26.1 million at December 31, 2012 for two qualified, defined benefit pension plans. The assets funding these plans are in a separate trust and are not considered assets of the Company or included in the Company's balance sheets. The Contractual Obligations table above includes \$975,000, reflecting the expected payments we will make to the trust funds in 2013. Additional contributions may be required in future years based on the actual return earned by the plan assets and other actuarial assumptions, such as the discount rate and long-term expected rate of return on plan assets. See Item 8 under the heading Notes to the Consolidated Financial Statements Note 15, Employee Benefit Plans, for further information on the plans. Additionally, the Contractual Obligations table includes deferred compensation obligations totaling \$2.2 million funded with Rabbi Trust assets in the same amount. The Rabbi Trust assets are recorded under Investments on the Balance Sheet. We assume a retirement age of 65 for purposes of distribution from this account.

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. Neither of these subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at December 31, 2012 was \$29.7 million, with the guarantees expiring on various dates through December 2013.

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In addition to the corporate guarantees, we have issued a letter of credit for \$1.0 million, which expires on September 12, 2013, related to the electric transmission services for FPU's northwest electric division. We have also issued a letter of credit to our current primary insurance company for \$656,000, which expires on December 2, 2013, as security to satisfy the deductibles under our various insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for \$304,000 to our former primary insurance company, which will expire on June 1, 2013. There have been no draws on these letters of credit as of December 31, 2012. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

We provided a letter of credit for \$2.3 million to TETLP related to the precedent agreement, which is further described in Item 8 under the heading, Notes to the Consolidated Financial Statements Note 19, Other Commitments and Contingencies.

(f) Rate Filings and Other Regulatory Activities

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by the PSC in their respective states; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At December 31, 2012, Chesapeake was involved in rate filings and/or regulatory matters in each of the jurisdictions in which it operates. Each of these rate filings or regulatory matters is fully described in Item 8 under the heading Notes to the Consolidated Financial Statements Note 17, Rates and Other Regulatory Activities.

(g) Environmental Matters

We continue to work with federal and state environmental agencies to assess the environmental impact and explore corrective action at seven environmental sites (see Item 8 under the heading Notes to the Consolidated Financial Statements Note 18, Environmental Commitments and Contingencies for further detail on each site). 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.

Table of Contents**(h) Market Risk**

Market risk represents the potential loss arising from adverse changes in market rates and prices. Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt consists of fixed-rate senior notes, secured debt and convertible debentures. All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities, was \$110.1 million at December 31, 2012, as compared to a fair value of \$133.2 million, using a discounted cash flow methodology that incorporates a market interest rate is based on published corporate borrowing rates for debt instruments with similar terms and average maturities with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

Our propane distribution business is exposed to market risk as a result of propane storage activities and entering into fixed price contracts for supply. We can store up to approximately 5.4 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline. To mitigate the impact of price fluctuations, we have adopted a Risk Management Policy that allows the propane distribution operation to enter into fair value hedges or other economic hedges of our inventory.

In May 2012, our propane distribution operation entered into call options to protect against an increase in propane prices associated with 1,260,000 gallons purchased for the propane price cap program from December 2012 through March 2013. The call options are exercised if the propane prices rise above the strike prices, which range from \$0.905 per gallon to \$0.99 per gallon during this four-month period. We will receive the difference between the market price and the strike price during those months. We paid \$139,000 to purchase the call options, and we accounted for the call options as a fair value hedge. As of December 31, 2012, the call options had a fair value of \$28,000. There was no ineffective portion of this fair value hedge in 2012.

In August 2011, our propane distribution operation entered into a put option to protect against the decline in propane prices and related potential inventory losses associated with 630,000 gallons purchased for the propane price cap program for the upcoming heating season. This put option was exercised as the propane prices fell below the strike price of \$1.445 per gallon in January through March 2012. We received \$118,000, representing the difference between the market price and the strike price during those months. We had paid \$91,000 to purchase the put option, and we accounted for it as a fair value hedge.

Our propane wholesale marketing operation is a party to natural gas liquids forward contracts, primarily propane contracts, with various third parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are typically settled financially without taking physical delivery of propane. The propane wholesale marketing operation also enters into futures contracts that are traded on the IntercontinentalExchange. In certain cases, the futures contracts are settled by the payment or receipt of a net amount equal to the difference between the current market price of the futures contract and the original contract price; however, they may also be settled by physical receipt or delivery of propane.

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

Quantitative information on forward, futures and other contracts at December 31, 2012 and 2011 is presented in the following tables:

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At December 31, 2012	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	1,262,000	\$ 0.7550	\$1.3650	\$ 0.9214
Purchase	2,648,000	\$ 0.7550	\$1.3300	\$ 0.9291

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

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

At December 31, 2011	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	12,075,000	\$ 1.3100	\$1.6063	\$ 1.4785
Purchase	11,928,000	\$ 1.3050	\$1.6000	\$ 1.4630

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

All contracts expire by the end of the second quarter of 2012.

At December 31, 2012 and 2011, we marked these forward and other contracts to market, using market transactions in either the listed or over-the-counter (OTC) markets, which resulted in the following assets and liabilities:

<i>(in thousands)</i>	2012	2011
Mark-to-market energy assets, including put option	\$ 210	\$ 1,754
Mark-to-market energy liabilities	\$ 331	\$ 1,496

Our natural gas distribution, electric distribution and natural gas marketing operations have entered into agreements with various suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered normal purchases and sales and are accounted for on an accrual basis.

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(i) Competition

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

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

Our propane distribution operations compete with several other propane distributors in their respective geographic markets, primarily on the basis of service and price. We emphasize 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 unit of heat value. Propane also competes with home heating oil as an energy source. Since natural gas has historically been less expensive than propane, propane is generally not distributed in geographic areas served by natural gas pipeline or distribution systems.

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

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

Table of Contents**(j) 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.

(k) Marianna Franchise

On March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida. In the complaint, the City of Marianna alleged three breaches of the franchise agreement by FPU: (i) FPU failed to develop and implement time-of-use (TOU) and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) mutually agreed upon TOU and interruptible rates by FPU were not effective or in effect by February 17, 2011; and (iii) FPU did not have such rates available to all of FPU s customers located within and without the corporate limits of the City of Marianna. The City of Marianna is seeking a declaratory judgment allowing it to exercise its option under the franchise agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the City Commission of Marianna, Florida (the Marianna Commission), which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum is approved by the voters, the closing of the purchase must occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. On August 3, 2011, the City of Marianna notified FPU that it was formally exercising its option to purchase FPU s property. On August 31, 2011, FPU advised the City of Marianna that it has no right to exercise the purchase option under the franchise agreement and that FPU would continue to oppose the effort by the City of Marianna to purchase FPU s property. In December 2011, the City of Marianna filed a motion for summary judgment. FPU opposed the motion. On April 3, 2012, the court conducted a hearing on the City of Marianna s motion for summary judgment. The court subsequently denied in part and granted in part the City of Marianna s motion after concluding that issues of fact remained with respect to each of the three alleged breaches of the franchise agreement. Mediation was conducted on May 11, 2012, and again on July 6, 2012, but no resolution was reached. The case was originally scheduled for trial in October 2012; however, due to a scheduling conflict, the trial has been rescheduled to February 11, 2013. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. The agreement in principle requires the City of Marianna and FPU to negotiate and prepare a formal settlement agreement that is subject to approval by FPU s Board of Directors and the Marianna Commission. The settlement agreement would contemplate, in pertinent part, the sale of FPU s facilities within the City of Marianna s corporate limits to the City of Marianna and, in connection therewith, require the City of Marianna to enter into an operating agreement with FPU pursuant to which FPU will operate and maintain the facilities sold to the City of Marianna. The agreement in principle requires FPU and the City of Marianna to submit the formal settlement agreement to the FPU Board of Directors and Marianna Commission for approval by March 15, 2013. If the settlement agreement is approved by both the FPU Board of Directors and the Marianna Commission, the agreement in principle requires the City of Marianna to proceed with a referendum on the acquisition of FPU s facilities in April 2013 or as soon as practicable thereafter and prohibits FPU from opposing or interfering with that referendum. If the settlement agreement is not approved by either the FPU Board of Directors or the Marianna Commission, the agreement in principle permits the City of Marianna to proceed immediately with a referendum on the acquisition of FPU s facilities and permits FPU to contest that referendum. The agreement in principle further provides that (i) if the contested referendum fails, FPU s franchise with the City of Marianna shall be extended 10 years from the current expiration date in 2020; and (ii) if the contested referendum passes, the terms of the City of Marianna s purchase of FPU s facilities within the City of Marianna will be set pursuant to the procedures in the current franchise agreement. FPU and the City of Marianna are presently negotiating the terms of the formal settlement agreement and related operating agreement. Total litigation expense associated with the City of Marianna litigation is approximately \$1.4 million as of December 31, 2012. These costs have been expensed as incurred, however, the Florida PSC has permitted FPU to seek recovery in a future rate proceeding.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Information concerning quantitative and qualitative disclosure about market risk is included in Item 7 under the heading Management's Discussion and Analysis of Financial Condition and Results of Operations - Market Risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of

Chesapeake Utilities Corporation

We have audited the accompanying consolidated balance sheets of Chesapeake Utilities Corporation (the Company) as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2012. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Chesapeake Utilities Corporation as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Chesapeake Utilities Corporation's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 8, 2013 expressed an unqualified opinion.

/s/ ParenteBeard LLC

ParenteBeard LLC

Philadelphia, Pennsylvania

March 8, 2013

Table of Contents**Consolidated Statements of Income**

For the Years Ended December 31, <i>(in thousands, except shares and per share data)</i>	2012	2011	2010
Operating Revenues			
Regulated Energy	\$ 246,208	\$ 256,226	\$ 269,438
Unregulated Energy	133,049	149,586	146,793
Other	13,245	12,215	11,315
Total operating revenues	392,502	418,027	427,546
Operating Expenses			
Regulated energy cost of sales	111,402	128,111	145,207
Unregulated energy and other cost of sales	101,957	118,787	116,098
Operations	82,387	79,810	77,227
Maintenance	7,423	7,449	7,484
Depreciation and amortization	22,510	20,153	18,536
Other taxes	10,188	10,012	11,064
Total operating expenses	335,867	364,322	375,616
Operating Income	56,635	53,705	51,930
Other income, net of other expenses	271	906	195
Interest charges	8,747	9,000	9,146
Income Before Income Taxes	48,159	45,611	42,979
Income taxes	19,296	17,989	16,923
Net Income	\$ 28,863	\$ 27,622	\$ 26,056
Weighted Average Common Shares Outstanding:			
Basic	9,586,144	9,555,799	9,474,554
Diluted	9,671,507	9,651,058	9,582,374
Earnings Per Share of Common Stock:			
Basic	\$ 3.01	\$ 2.89	\$ 2.75
Diluted	\$ 2.99	\$ 2.87	\$ 2.73
Cash Dividends Declared Per Share of Common Stock	\$ 1.440	\$ 1.365	\$ 1.305

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

Table of Contents**Consolidated Statements of Comprehensive Income**

For the Years Ended December 31, (in thousands)	2012	2011	2010
Net Income	\$ 28,863	\$ 27,622	\$ 26,056
Other Comprehensive Loss, net of tax:			
Employee Benefits, net of tax:			
Amortization of prior service cost, net of tax of (\$26), \$432 and \$5, respectively	(37)	645	8
Net Gain, net of tax of (\$331), (\$1,164) and (\$541), respectively	(498)	(1,812)	(844)
Total other comprehensive loss	(535)	(1,167)	(836)
Comprehensive Income	\$ 28,328	\$ 26,455	\$ 25,220

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

Table of Contents**Consolidated Statements of Cash Flows**

For the Years Ended December 31, <i>(in thousands)</i>	2012	2011	2010
<i>Operating Activities</i>			
Net Income	\$ 28,863	\$ 27,622	\$ 26,056
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	22,510	20,153	18,536
Depreciation and accretion included in other costs	5,547	5,116	4,365
Deferred income taxes, net	13,881	17,320	13,332
(Gain) loss on sale of assets	93	(453)	113
Unrealized (gain) loss on commodity contracts	339	(41)	(116)
Unrealized gain on investments	(451)	(282)	(181)
Realized gain on sale of investments, net	(88)		
Employee benefits and compensation	576	1,457	1,801
Share based compensation	1,419	1,450	1,155
Other, net	(27)	(50)	(17)
Changes in assets and liabilities:			
Sale (purchase) of investments	(301)	660	(297)
Accounts receivable and accrued revenue	21,549	14,979	(20,467)
Propane inventory, storage gas and other inventory	603	(2,484)	151
Regulatory assets	252	(18)	1,659
Prepaid expenses and other current assets	(713)	(345)	1,157
Other deferred charges	26	179	(156)
Long-term receivables	(290)	76	286
Accounts payable and other accrued liabilities	(19,936)	(13,612)	15,853
Income taxes receivable	2,223	(185)	(3,761)
Accrued interest	(200)	(152)	(97)
Customer deposits and refunds	(1,647)	5,096	2,038
Accrued compensation	437	19	1,339
Regulatory liabilities	(5,220)	(2,527)	740
Other liabilities	(3,573)	(2,893)	(2,371)
Net cash provided by operating activities	65,872	71,121	61,118
<i>Investing Activities</i>			
Property, plant and equipment expenditures	(72,007)	(47,037)	(45,637)
Proceeds from sale of assets	2,279	937	113
Sale (Purchase) of investments	506	(1,091)	(3,108)
Environmental expenditures	(607)	(645)	(290)
Net cash used by investing activities	(69,829)	(47,836)	(48,922)
<i>Financing Activities</i>			
Common stock dividends	(12,335)	(11,663)	(11,013)
(Purchase) issuance of stock for Dividend Reinvestment Plan	(1,273)	(1,244)	568
Change in cash overdrafts due to outstanding checks	597	91	3,255
Net borrowing (repayment) under line of credit agreements	25,894	(241)	1,579
Other short-term borrowing		(29,100)	29,100
Proceeds from issuance of long-term debt		29,000	
Repayment of long-term debt	(8,202)	(9,134)	(36,860)
Net cash provided (used) by financing activities	4,681	(22,291)	(13,371)

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<i>Net Increase (Decrease) in Cash and Cash Equivalents</i>	724	994	(1,175)
<i>Cash and Cash Equivalents Beginning of Period</i>	2,637	1,643	2,818
<i>Cash and Cash Equivalents End of Period</i>	\$ 3,361	\$ 2,637	\$ 1,643

Supplemental Cash Flow Disclosures (see Note 6)

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

Table of Contents**Consolidated Balance Sheets**

	December 31, 2012	December 31, 2011
Assets		
<i>(in thousands, except shares and per share data)</i>		
Property, Plant and Equipment		
Regulated energy	\$ 585,429	\$ 528,790
Unregulated energy	70,218	67,327
Other	20,067	19,988
Total property, plant and equipment	675,714	616,105
Less: Accumulated depreciation and amortization	(155,378)	(137,784)
Plus: Construction work in progress	21,445	9,383
Net property, plant and equipment	541,781	487,704
Current Assets		
Cash and cash equivalents	3,361	2,637
Accounts receivable (less allowance for uncollectible accounts of \$826 and \$1,090, respectively)	53,787	76,605
Accrued revenue	11,688	10,403
Propane inventory, at average cost	7,612	9,726
Other inventory, at average cost	5,841	4,785
Regulatory assets	2,736	1,846
Storage gas prepayments	3,716	5,003
Income taxes receivable	4,703	6,998
Deferred income taxes	791	2,712
Prepaid expenses	6,020	5,072
Mark-to-market energy assets	210	1,754
Other current assets	132	219
Total current assets	100,597	127,760
Deferred Charges and Other Assets		
Goodwill	4,090	4,090
Other intangible assets, net	2,798	3,127
Investments, at fair value	4,168	3,918
Regulatory assets	77,408	79,256
Receivables and other deferred charges	2,904	3,211
Total deferred charges and other assets	91,368	93,602
Total Assets	\$ 733,746	\$ 709,066

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

Table of Contents**Consolidated Balance Sheets**

	December 31, 2012	December 31, 2011
Capitalization and Liabilities		
<i>(in thousands, except shares and per share data)</i>		
Capitalization		
Stockholders' equity		
Common stock, par value \$0.4867 per share (authorized 25,000,000)	\$ 4,671	\$ 4,656
Additional paid-in capital	150,750	149,403
Retained earnings	106,239	91,248
Accumulated other comprehensive loss	(5,062)	(4,527)
Deferred compensation obligation	982	817
Treasury stock	(982)	(817)
Total stockholders' equity	256,598	240,780
Long-term debt, net of current maturities	101,907	110,285
Total capitalization	358,505	351,065
Current Liabilities		
Current portion of long-term debt	8,196	8,196
Short-term borrowing	61,199	34,707
Accounts payable	41,992	55,581
Customer deposits and refunds	29,271	30,918
Accrued interest	1,437	1,637
Dividends payable	3,502	3,300
Accrued compensation	7,435	6,932
Regulatory liabilities	1,577	6,653
Mark-to-market energy liabilities	331	1,496
Other accrued liabilities	7,226	8,079
Total current liabilities	162,166	157,499
Deferred Credits and Other Liabilities		
Deferred income taxes	125,205	115,624
Deferred investment tax credits	113	171
Regulatory liabilities	5,454	3,564
Environmental liabilities	9,114	9,492
Other pension and benefit costs	33,535	33,798
Accrued asset removal cost	38,096	36,584
Other liabilities	1,558	1,269
Total deferred credits and other liabilities	213,075	200,502
Other commitments and contingencies (Note 18 and 19)		
Total Capitalization and Liabilities	\$ 733,746	\$ 709,066

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

Table of Contents**Consolidated Statements of Stockholders Equity**

	Common Stock			Accumulated Other				Total
	Number of Shares ⁽¹⁾	Par Value	Additional Paid-In Capital	Retained Earnings	Comprehensive Loss	Deferred Compensation	Treasury Stock	
<i>(in thousands, except shares and per share data)</i>								
Balances at December 31, 2009	9,394,314	\$ 4,572	\$ 144,502	\$ 63,231	(\$2,524)	\$ 739	(\$739)	209,781
Net Income				26,056				26,056
Other comprehensive loss					(836)			(836)
Dividend Reinvestment Plan	53,806	26	1,699					1,725
Retirement Savings Plan	27,795	14	889					903
Conversion of debentures	11,865	6	196					202
Share-based compensation ^{(2) (3)}	36,415	17	620					637
Tax benefit on share-based compensation			253					253
Deferred Compensation Plan						38	(38)	
Purchase of treasury stock	(1,144)						(38)	(38)
Sale and distribution of treasury stock	1,144						38	38
Dividends on share-based compensation				(104)				(104)
Cash dividends ⁽⁴⁾				(12,378)				(12,378)
Balances at December 31, 2010	9,524,195	4,635	148,159	76,805	(3,360)	777	(777)	226,239
Net Income				27,622				27,622
Other comprehensive loss					(1,167)			(1,167)
Dividend Reinvestment Plan			(22)					(22)
Retirement Savings Plan	2,002	1	79					80
Conversion of debentures	10,680	5	176					181
Share-based compensation ^{(2) (3)}	30,430	15	998					1,013
Tax benefit on share-based compensation			13					13
Deferred Compensation Plan						40	(40)	
Purchase of treasury stock	(993)						(40)	(40)
Sale and distribution of treasury stock	993						40	40
Dividends on share-based compensation				(129)				(129)
Cash dividends ⁽⁴⁾				(13,050)				(13,050)
Balances at December 31, 2011	9,567,307	4,656	149,403	91,248	(4,527)	817	(817)	240,780
Net Income				28,863				28,863
Other comprehensive loss					(535)			(535)
Dividend Reinvestment Plan			(7)					(7)
Conversion of debentures	10,975	5	181					186
Share-based compensation ^{(2) (3)}	19,217	10	1,001					1,011
Tax benefit on share-based compensation			172					172
Deferred Compensation Plan						165	(165)	
Purchase of treasury stock	(1,019)						(45)	(45)
Sale and distribution of treasury stock	1,019						45	45
Dividends on share-based compensation				(64)				(64)
Cash dividends ⁽⁴⁾				(13,808)				(13,808)
Balances at December 31, 2012	9,597,499	\$ 4,671	\$ 150,750	\$ 106,239	(\$5,062)	\$ 982	(\$982)	\$ 256,598

(1) Includes 33,461, 30,597 and 29,596, shares at December 31, 2012, 2011 and 2010, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

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

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For 2012, 2011 and 2010, the Company withheld 5,670, 12,234 and 17,695 shares, respectively, for taxes.

(4) Cash dividends per share for the periods ended December 31, 2012, 2011 and 2010 were \$1.440, \$1.365, and \$1.305 respectively.

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

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Notes to the Consolidated Financial Statements

1. ORGANIZATION AND BASIS OF PRESENTATION

Chesapeake, incorporated in 1947 in Delaware, is a diversified utility company engaged in regulated energy, unregulated energy and other unregulated businesses. Our regulated energy businesses consist of: (a) regulated natural gas distribution operations in central and southern Delaware, Maryland's eastern shore and Florida; (b) regulated natural gas transmission operations on the Delmarva Peninsula, in Pennsylvania and in Florida; and (c) regulated electric distribution operation serving customers in northeast and northwest Florida. Our unregulated energy businesses include: (a) propane distribution operations in Delaware, the eastern shore of Maryland and Virginia, southeastern Pennsylvania and Florida; (b) propane wholesale marketing operation, which markets propane to major independent oil and petrochemical companies, wholesale resellers and retail propane companies located primarily in the southeastern United States; and (c) natural gas marketing operation providing natural gas supplies directly to commercial and industrial customers in Florida, Delaware and Maryland. We also engage in non-energy businesses, primarily through our advanced information services subsidiary, which provides information-technology-related business services and solutions for both enterprise and e-business applications.

Our consolidated financial statements as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 have been prepared in compliance with the rules and regulations of the SEC and GAAP. Our consolidated financial statements include the accounts of Chesapeake and its wholly owned subsidiaries. We do not have any ownership interests in investments accounted for using the equity method or any variable interests in a variable interest entity. All intercompany transactions have been eliminated in consolidation. We have assessed and reported on subsequent events through the date of issuance of these consolidated financial statements.

We reclassified certain amounts in the consolidated statements of income and consolidated statements of cash flows for the years ended December 31, 2011 and 2010 and in the consolidated balance sheet as of December 31, 2011, to conform to the current year's presentation. We also reclassified certain segment information as of December 31, 2011, and for the years ended December 31, 2011 and 2010, to conform to the current year's presentation. These reclassifications are considered immaterial to the overall presentation of our consolidated financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates in measuring assets and liabilities and related revenues and expenses. These estimates involve judgments with respect to, among other things, various future economic factors that are difficult to predict and are beyond our control; therefore, actual results could differ from these estimates.

Table of Contents**Notes to the Consolidated Financial Statements*****Property, Plant and Equipment***

Property, plant and equipment are stated at original cost less accumulated depreciation or fair value, if impaired. Costs include direct labor, materials and third-party construction contractor costs, allowance for funds used during construction (AFUDC), and certain indirect costs related to equipment and employees engaged in construction. The costs of repairs and minor replacements are charged against income as incurred, and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of property owned by the unregulated businesses, the gain or loss, net of salvage value, is charged to income. Upon retirement or disposition of property within the regulated businesses, the gain or loss, net of salvage value, is charged to accumulated depreciation. A summary of property, plant and equipment by classification as of December 31, 2012 and 2011 is provided in the following table:

<i>(in thousands)</i>	December 31, 2012	December 31, 2011
Property, plant and equipment		
Regulated Energy		
Natural gas distribution Delmarva	\$ 149,558	\$ 140,800
Natural gas distribution Florida	170,943	158,341
Natural gas transmission	202,968	173,810
Electric distribution Florida	61,960	55,839
Unregulated Energy		
Propane distribution Delmarva	53,156	51,250
Propane distribution Florida	16,823	15,839
Other unregulated energy	239	238
Other	20,067	19,988
Total property, plant and equipment	675,714	616,105
Less: Accumulated depreciation and amortization	(155,378)	(137,784)
Plus: Construction work in progress	21,445	9,383
Net property, plant and equipment	\$ 541,781	\$ 487,704

Contributions or Advances in Aid of Construction

Customer contributions or advances in aid of construction reduce property, plant and equipment unless the amounts are refundable to customers. Contributions or advances may be refundable to customers after a number of years based on the amount of revenues generated from the customers or the duration of the service provided to the customers. Refundable contributions or advances are recorded initially as liabilities. The amounts that are determined to be non-refundable reduce property, plant and equipment at the time of such determination. During the years ended December 31, 2012 and 2011, there were \$1.1 million and \$286,000, respectively, of non-refunded contributions or advances reducing property, plant and equipment.

Allowed Funds Used During Construction

Some of the additions to our regulated property, plant and equipment include AFUDC, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects. AFUDC is capitalized in rate base for rate making purposes when the completed projects are placed in service. During the years ended December 31, 2012 and 2011, we recorded \$111,000 and \$25,000, respectively, of AFUDC, all of which were related to short-term debt and reflected as a reduction of interest charges.

Asset Used in Leases

Property, plant and equipment for the natural gas transmission operation includes \$1.4 million of assets, consisting primarily of mains, measuring equipment and regulation station equipment used by Peninsula Pipeline to provide natural gas transmission service pursuant to a

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contract with a third party. This contract is accounted for as an operating lease due to the exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and generates \$264,000 in annual revenue for a term of 20 years. Accumulated depreciation for these assets totaled \$291,000 and \$218,000 at December 31, 2012 and 2011, respectively.

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Table of Contents**Notes to the Consolidated Financial Statements**

Property, plant and equipment for the natural gas transmission operation also includes \$6.7 million of assets, which consists of the 16-mile pipeline from the Duval/Nassau County line to Amelia Island in Nassau County, Florida, jointly owned by Peninsula Pipeline and Peoples Gas. The amount included in property, plant and equipment represents Peninsula Pipeline's 45-percent ownership of this pipeline. This 16-mile pipeline was placed in service in December 2012. Accumulated depreciation for this pipeline totaled \$28,000 at December 31, 2012.

In July 2011, we sold an Internet Protocol address asset to an unaffiliated entity for approximately \$553,000. This particular Internet Protocol address was not used by us and did not have any net carrying value at the time of the sale. We recognized a non-operating pre-tax gain of \$553,000 from this sale, which is included in other income in the accompanying consolidated statements of income.

In September 2011, FPU entered into an agreement with an unaffiliated entity to sell its office building located in West Palm Beach, Florida for \$2.2 million, which was finalized in February 2012 and did not result in a material gain. We treated the West Palm Beach office building as an asset held for sale, and it was included in other property, plant and equipment at December 31, 2011 in the accompanying consolidated balance sheet.

In June and July 2012, FPU entered into contracts to exchange land located in West Palm Beach, Florida for a different parcel of land located in the same city. Under the same contracts, FPU also agreed to purchase a second parcel of land located in the same city for approximately \$600,000. In early 2013, FPU terminated these contracts.

Depreciation and Accretion Included in Operations Expenses

We compute depreciation expense for our regulated operations by applying composite, annual rates, as approved by the regulators. The following table shows the average depreciation rates used during the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2010
Natural gas distribution Delmarva	2.6%	2.5%	2.5%
Natural gas distribution Florida	3.5%	3.5%	3.2%
Natural gas transmission	2.5%	2.6%	2.7%
Electric distribution Florida	4.2%	4.2%	3.8%

For our unregulated operations, we compute depreciation expense on a straight line basis over the following estimated useful lives of the assets:

Asset Description	Useful Life
Propane distribution mains	10-37 years
Propane bulk plants and tanks	7-40 years
Liquified petroleum gas equipment	5-40 years
Meters and meter installations	5-33 years
Measuring and regulating station equipment	5-37 years
Office furniture and equipment	3-10 years
Transportation equipment	3-20 years
Structures and improvements	3-45 years
Other	Various

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Notes to the Consolidated Financial Statements

We report certain depreciation and accretion in operations expense rather than depreciation and amortization expense in the accompanying consolidated statements of income in accordance with industry practice and regulatory requirements. Depreciation and accretion included in operations expense consists of the accretion of the costs of removal for future retirements of utility assets, vehicle depreciation, computer software and hardware depreciation, and other minor amounts of depreciation expense. For the years ended December 31, 2012, 2011 and 2010, \$5.5 million, \$5.1 million and \$4.4 million, respectively, of depreciation and accretion were reported in operations expenses.

Table of Contents**Notes to the Consolidated Financial Statements****Regulated Operations**

We account for our regulated operations in accordance with ASC Topic 980, Regulated Operations. This Topic includes accounting principles for companies whose rates are determined by independent third-party regulators. When setting rates, regulators often make decisions, the economics of which require companies to defer costs or revenues in different periods than may be appropriate for unregulated enterprises. When this situation occurs, a regulated company defers the associated costs as regulatory assets on the balance sheet and records them as expense on the income statement as it collects revenues. Further, regulators can also impose liabilities upon a regulated company for amounts previously collected from customers, and for recovery of costs that are expected to be incurred in the future as regulatory liabilities. If we were required to terminate the application of these regulatory provisions to our regulated operations, all such deferred amounts would be recognized in the statement of income at that time, which could have a material impact on our financial position, results of operations and cash flows.

At December 31, 2012 and 2011, the regulated utility operations had recorded the following regulatory assets and liabilities included in our consolidated balance sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers' rates.

	December 31, 2012	December 31, 2011
<i>(in thousands)</i>		
Regulatory Assets		
Underrecovered purchased fuel costs ⁽¹⁾	\$ 2,219	\$ 911
Deferred post retirement benefits ⁽²⁾	17,755	15,640
Deferred transaction and transition costs ⁽³⁾	1,035	1,600
Deferred conversion and development costs ⁽¹⁾	842	1,143
Environmental regulatory assets and expenditures ⁽⁴⁾	5,432	6,131
Acquisition adjustment ⁽⁵⁾	48,724	50,546
Loss on reacquired debt ⁽⁶⁾	1,484	1,576
Other	2,653	3,555
Total Regulatory Assets	\$ 80,144	\$ 81,102
Regulatory Liabilities		
Self insurance ⁽¹⁰⁾	\$ 1,212	\$ 1,010
Overrecovered purchased fuel costs ⁽¹⁾	218	4,664
Conservation cost recovery ⁽¹⁾	356	12
Rate Refund ⁽⁷⁾		1,250
Storm reserve ⁽¹⁰⁾	2,742	2,812
Accrued asset removal cost ⁽⁹⁾	38,096	36,584
Deferred gains ⁽⁸⁾	1,977	
Other	526	469
Total Regulatory Liabilities	\$ 45,127	\$ 46,801

⁽¹⁾ We are allowed to recover the asset or are required to pay the liability in rates. We do not earn an overall rate of return on these assets.

⁽²⁾ The Florida PSC allowed FPU to treat as a regulatory asset the portion of the unrecognized costs pursuant to ASC Topic 715 related to its regulated operations. See Note 15, Employee Benefit Plans, for additional information.

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- (3) The Florida PSC approved the inclusion of the FPU merger-related costs in our rate base and the recovery of those costs in rates. The balances at December 31, 2012 and 2011 include the gross-up of this regulatory asset for income tax because a portion of the merger-related costs is not tax-deductible.
- (4) All of our environmental expenditures incurred to date and current estimate of future environmental expenditures have been approved by various PSCs for recovery. See Note 18, Environmental Commitments and Contingencies, for additional information on our environmental contingencies.

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Notes to the Consolidated Financial Statements

- (5) The Florida PSC approved the inclusion of approximately \$1.3 million of the premium paid by FPU for an acquisition of another natural gas utility in 2002 (prior to Chesapeake's acquisition of FPU) in its rate base and the recovery of it in rates. The Florida PSC also approved the inclusion of approximately \$34.2 million of the premium paid by Chesapeake in its acquisition of FPU in the rate base and the recovery of it in rates. During 2012, we reclassified to a regulatory asset that portion of the goodwill related to the FPU acquisition, which was approved for recovery in future rates, along with the related gross-up for income taxes. See Note 17, Rates and Other Regulatory Activities, for additional information.
- (6) Gains and losses resulting from the reacquisition of long-term debt are amortized over future periods as adjustments to interest expense in accordance with established regulatory practice.
- (7) Eastern Shore refunded this amount to customers in February 2012 as a result of a rate case settlement. See Note 17, Rates and Other Regulatory Activities, for additional information.
- (8) Deferred gains represent: (i) a one-time contingency gain and a tax gross-up related to FPU's income tax liability, which originated prior to the acquisition by Chesapeake from excess tax depreciation on vehicles (see Note 17, Rates and Other Regulatory Activities, for additional information); and (ii) a deferral of a curtailment gain related to FPU's postretirement medical benefit associated with a change in plan provisions that became effective January 1, 2012 (see Note 15, Employee Benefit Plans, for additional information).
- (9) In accordance with regulatory treatment our depreciation rates are comprised of two components—historical cost and the estimated cost of removal, net of estimated salvage, of certain regulated properties. We collect these costs in base rates through depreciation expense with a corresponding credit to accumulated depreciation. Because the accumulated estimated removal costs meet the requirements of authoritative guidance related to regulated operations, we have accounted for them as a regulatory liability and have reclassified them from accumulated depreciation to accumulated removal costs in our consolidated balance sheets.
- (10) We have self insurance and storm reserves that allow us to collect through rates amounts to be used against general claims, storm restoration costs and other losses as they are incurred.

We monitor our regulatory and competitive environments to determine whether the recovery of our regulatory assets continues to be probable. If we were to determine that recovery of these assets is no longer probable, we would write off the assets against earnings. We believe that provisions of ASC Topic 980, Regulated Operations, continue to apply to our regulated operations and that the recovery of our regulatory assets is probable.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSC in each state in which they operate. Eastern Shore's revenues are based on rates approved by the FERC. Customers' base rates may not be changed without formal approval by these commissions. The PSCs, however, have authorized our regulated operations to negotiate rates, based on approved methodologies, with customers that have competitive alternatives. The FERC has also authorized Eastern Shore to negotiate rates above or below the FERC-approved maximum rates, which customers can elect as an alternative to negotiated rates.

For regulated deliveries of natural gas and electricity, we read meters and bill customers on monthly cycles that do not coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas and electricity that have been delivered, but not yet billed, at the end of an accounting period to the extent that they do not coincide. We estimate the amount of the unbilled revenue by jurisdiction and customer class. A similar computation is made to accrue unbilled revenues for propane customers with meters, such as community gas system customers, and natural gas marketing customers, whose billing cycles do not coincide with our accounting periods.

The propane wholesale marketing operation records trading activity for open contracts on a net mark-to-market basis in our consolidated statement of income. For propane bulk delivery customers without meters and advanced information services customers, we record revenue in the period the products are delivered and/or services are rendered.

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Notes to the Consolidated Financial Statements

Each of our natural gas distribution operations in Delaware and Maryland, our FPU natural gas operation and our electric distribution operation in Florida has a fuel cost recovery mechanism. This mechanism provides a method of adjusting the billing rates to reflect changes in the cost of purchased fuel. The difference between the current cost of fuel purchased and the cost of fuel recovered in billed rates is deferred and accounted for as either unrecovered fuel cost or amounts payable to customers. Generally, these deferred amounts are recovered or refunded within one year. Chesapeake's Florida natural gas distribution division provides only unbundled delivery service to its customers, whereby the customers are permitted to purchase their gas requirements directly from competitive natural gas marketers.

We charge flexible rates to our natural gas distribution industrial interruptible customers to compete with prices of alternative fuels, which these customers are able to use. Neither we nor our interruptible customers are contractually obligated to deliver or receive natural gas on a firm service basis.

We report revenue taxes, such as gross receipts taxes, franchise taxes, and sales taxes, on a net basis.

Cost of Sales

Cost of sales includes the direct costs attributable to the products sold or services we provide for our regulated energy, unregulated energy and other segments. These costs include primarily the variable cost of natural gas, electricity and propane commodities, pipeline capacity costs needed to transport and store natural gas, transmission costs for electricity, transportation costs to transport propane purchases to our storage facilities, and the direct cost of labor for our advanced information services operation.

Operations and Maintenance Expenses

Operations and maintenance expenses are costs associated with the operation and maintenance of our regulated and unregulated operations. Major cost components include operation and maintenance salaries and benefits, materials and supplies, usage of vehicles, tools and equipment, payments to contractors, utility plant maintenance, customer service, professional fees and other outside services, insurance expense, minor amounts of depreciation, accretion of cost of removal for future retirements of utility assets, and other administrative expenses.

Cash and Cash Equivalents

Our policy is to invest cash in excess of operating requirements in overnight income-producing accounts. Such amounts are stated at cost, which approximates fair value. Investments with an original maturity of three months or less when purchased are considered cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable consist primarily of amounts due for distribution sales of natural gas, electricity and propane and transportation services to customers. An allowance for doubtful accounts is recorded against amounts due to reduce the net receivables balance to the amount we reasonably expect to collect based upon our collections experiences and management's assessment of our customers' inability or reluctance to pay. If circumstances change, our estimates of recoverable accounts receivable may also change. Circumstances which could affect such estimates include, but are not limited to, customer credit issues, the level of natural gas, electricity and propane prices and general economic conditions. Accounts are written off when they are deemed to be uncollectible.

Inventories

We use the average cost method to value propane, materials and supplies, and other merchandise inventory. If market prices drop below cost, inventory balances that are subject to price risk are adjusted to market values.

Goodwill and Other Intangible Assets

Goodwill is not amortized but is tested for impairment at least annually. In addition, goodwill of a reporting unit is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. Other intangible assets are amortized on a straight-line basis over their estimated economic useful lives. Please refer to Note

10, Goodwill and Other Intangible Assets, for additional discussion of this subject.

Other Deferred Charges

Other deferred charges include discount, premium and issuance costs associated with long-term debt. Debt issuance costs are deferred and then are amortized to interest expense over the original lives of the respective debt issuances.

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Pension and Other Postretirement Plans

Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected returns on plan assets, assumed discount rates, the level of contributions made to the plans, and current demographic and actuarial mortality data. Management annually reviews the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities with the assistance of third-party actuarial firms. The assumed discount rates and the expected returns on plan assets are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rates, health care cost trend rates and rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rates are utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When estimating our discount rates, we consider high quality corporate bond rates, such as Moody's Aa bond index and the Citigroup yield curve, changes in those rates from the prior year and other pertinent factors, including the expected life of each of our plans and their respective payment options.

The expected long-term rates of return on assets are utilized in calculating the expected returns on the plan assets component of our annual pension plan costs. We estimate the expected returns on plan assets of each of our plans by evaluating expected bond returns, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rates of return on assets.

We estimate the assumed health care cost trend rates used in determining our postretirement net expense based upon actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual reviews of participant census information as of the measurement date.

Actual changes in the fair value of plan assets and the differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension and postretirement benefit costs that we ultimately recognize. A 0.25 percent decrease in the discount rate could increase our annual pension and postretirement costs by approximately \$11,000, and a 0.25 percent increase could decrease our annual pension and postretirement costs by approximately \$13,000. A 0.25 percent change in the rate of return could change our annual pension cost by approximately \$124,000 and would not have an impact on the postretirement and supplemental executive retirement plans because these plans are not funded.

Income Taxes and Investment Tax Credit Adjustments

Deferred tax assets and liabilities are recorded for the tax effect of temporary differences between the financial statement bases and tax bases of assets and liabilities and are measured using the enacted tax rates in effect in the years in which the differences are expected to reverse. The portions of our deferred tax liabilities applicable to regulated energy operations, which have not been reflected in current service rates, represent income taxes recoverable through future rates. Deferred tax assets are recorded net of any valuation allowance when it is more likely than not that such tax benefits will be realized. Investment tax credits on utility property have been deferred and are allocated to income ratably over the lives of the subject property.

We account for uncertainty in income taxes in the financial statements only if it is more likely than not that an uncertain tax position is sustainable based on technical merits. Recognizable tax positions are then measured to determine the amount of benefit recognized in the financial statements. We recognize penalties and interest related to unrecognized tax benefits as a component of other income.

Financial Instruments

Xeron, our propane wholesale marketing subsidiary, engages in trading activities using forward and futures contracts, which have been accounted for using the mark-to-market method of accounting. Under mark-to-market accounting, our trading contracts are recorded at fair value. The changes in market price are recognized as gains or losses in revenues on the consolidated statements of income in the period of change. Trading liabilities are recorded as mark-to-market energy liabilities. Trading assets are recorded as mark-to-market energy assets.

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Our natural gas, electric and propane distribution operations and natural gas marketing operations enter into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered normal purchases and sales and are accounted for on an accrual basis.

Our propane distribution operation may enter into derivative transactions, such as swaps and puts, in order to mitigate the impact of wholesale price fluctuations on its inventory valuation. These transactions may be designated as fair value hedges if they meet all of the accounting requirements pursuant to ASC 815 and we elect to designate the instruments as fair value hedges. If designated as a fair value hedge, the value of the hedging instrument, such as a swap or put, is recorded at fair value with the effective portion of the gain or loss of the hedging instrument effectively reducing or increasing the value of propane inventory. The ineffective portion of the gain or loss is recorded in earnings. If the instrument is not designated as a fair value hedge or does not meet the accounting requirements of a fair value hedge, it is recorded at fair value with the gain or loss being recorded in earnings.

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Standards Yet to be Adopted

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

In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The FASB issued ASU 2013-01 in response to concerns raised by constituents regarding the potential broad scope of disclosure requirements upon adoption of ASU 2011-11. It limits the scope of the new balance sheet offsetting disclosures to derivatives, repurchase agreements and securities lending transactions to the extent that they are (1) offsetting in the financial statements or (2) subject to an enforceable master netting arrangement or similar agreement. ASU 2013-01 will be effective for us on January 1, 2013. We expect the adoption of this standard to have no material effect on our financial position and results of operations.

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

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Recently Adopted Accounting Standards

In September 2011, the FASB issued ASU 2011-08, *Intangibles – Goodwill and Other (Topic 350): Testing Goodwill for Impairment*, which allows an entity to assess qualitatively whether it is necessary to perform step one of the two-step annual goodwill impairment test. Step one would be required if it is more likely than not that a reporting unit's fair value is less than its carrying amount. This differs from previous guidance, which required entities to perform step one of the test, at least annually, by comparing the fair value of a reporting unit to its carrying amount. An entity may elect to bypass the qualitative assessment and proceed directly to step one, for any reporting unit, in any period. ASU 2011-08 does not change the guidance on when to test goodwill for impairment. The amendments in ASU 2011-08 are effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We adopted ASU 2011-08, effective January 1, 2012. The adoption of ASU 2011-08 had no material impact on our financial position and results of operations.

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*. ASU 2011-04 does not extend the use of fair value accounting but provides guidance on how fair value accounting should be applied where its use is already required or permitted by other standards within International Financial Accounting Standards (IFRS) or GAAP. ASU 2011-04 supersedes most of the guidance in Topic 820, although many of the changes are clarifications of existing guidance or changes in wording to align with IFRS. Certain amendments in ASU 2011-04 change a particular principle or requirement for measuring fair value or disclosing information about fair value measurements. The amendments in ASU 2011-04 are effective for public entities for interim and annual periods beginning after December 15, 2011, and should be applied prospectively. We adopted ASU 2011-04, effective January 1, 2012, and provided additional disclosures as required. The adoption of ASU 2011-04 had no material impact on our financial position and results of operations.

Table of Contents**Notes to the Consolidated Financial Statements****3. EARNINGS PER SHARE**

Basic earnings per share are computed by dividing income available for common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted earnings per share are computed by dividing income available for common stockholders by the weighted average number of shares of common stock outstanding during the period adjusted for the exercise and/or conversion of all potentially dilutive securities, such as convertible debt and share-based compensation. The calculations of both basic and diluted earnings per share are presented in the following table.

For the Years Ended December 31, <i>(in thousands, except shares and per share data)</i>	2012	2011	2010
Calculation of Basic Earnings Per Share:			
Net Income	\$ 28,863	\$ 27,622	\$ 26,056
Weighted average shares outstanding	9,586,144	9,555,799	9,474,554
Basic Earnings Per Share	\$ 3.01	\$ 2.89	\$ 2.75
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income	\$ 28,863	\$ 27,622	\$ 26,056
Effect of 8.25% Convertible debentures	53	61	73
Adjusted numerator Diluted	\$ 28,916	\$ 27,683	\$ 26,129
Reconciliation of Denominator:			
Weighted shares outstanding Basic	9,586,144	9,555,799	9,474,554
Effect of dilutive securities:			
Share-based Compensation	23,499	23,792	22,550
8.25% Convertible debentures	61,864	71,467	85,270
Adjusted denominator Diluted	9,671,507	9,651,058	9,582,374
Diluted Earnings Per Share	\$ 2.99	\$ 2.87	\$ 2.73

4. ACQUISITIONS***Pending Acquisition of Eastern Shore Gas Company***

On June 22, 2012, we entered into an agreement to purchase the operating assets of ESG. These assets are currently used to provide propane distribution service in Worcester County, Maryland to approximately 11,000 residential and commercial customers through underground propane gas distribution systems and to over 500 customers through bulk propane delivery service. The purchase price is approximately \$16.5 million, which is subject to certain adjustments as specified in the purchase agreement. At closing, we will enter into a capacity, supply and operating agreement with ESG for supply and storage of propane, which will be utilized to serve the ESG system customers. We are evaluating the potential conversion of some of the underground propane distribution systems to natural gas where it is both economical and feasible. The transaction is subject to approval by the Maryland PSC, the receipt of consents of certain local jurisdictions to the assignment of certain franchise agreements and satisfaction of other closing conditions. On September 7, 2012, we filed an application with the Maryland PSC for approval of the purchase (see Note 17, Rates and Other Regulatory Activities, for additional information). The transaction, which is a cash purchase of assets, is expected to be completed in 2013. We expect to finance the acquisition using unsecured short-term debt.

Natural Gas Acquisition

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On August 9, 2010, FPU purchased the natural gas operating assets of IGC, which provides natural gas distribution service to approximately 700 customers, including two large industrial customers in Indiantown, Florida. FPU paid approximately \$1.2 million for these assets. FPU recorded \$742,000 in goodwill in connection with this acquisition, all of which was deductible for income tax purposes. In December 2012, FPU filed a petition with the Florida PSC, requesting approval to include the \$742,000 premium paid in this acquisition in rate base and amortize it over a 15-year period (see Note 17, Rates and Other Regulatory Activities for additional information). There was no intangible asset recorded in connection with this acquisition. The revenue and net income from this acquisition, which are included in our consolidated statements of income, are not material.

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Propane Acquisitions

On February 4, 2010, Sharp, our propane distribution subsidiary, purchased the operating assets of Virginia LP Gas, Inc. (Virginia LP), a propane distributor serving approximately 1,000 retail customers in Northampton and Accomack Counties in Virginia. The total consideration for the purchase was \$600,000, \$300,000 of which was paid at the closing and the remaining \$300,000 is to be paid over 60 months. Based on our valuation, we allocated \$188,000 of the purchase price to intangible assets, which consist of customer lists and non-compete agreements. These intangible assets are being amortized over a seven-year period. There was no goodwill recorded in connection with this acquisition. The revenue and net income from this acquisition, which are included in our consolidated statements of income, are not material.

In December 2011 and January 2012, Flo-gas Corporation, the propane distribution subsidiary of FPU, purchased the operating assets of Crescent Propane, Inc. (Crescent) and Barefoot Bay Propane Gas Company for total consideration of approximately \$954,000. In connection with these acquisitions, we recorded \$200,000 in goodwill, all of which is deductible for income tax purposes. There was no intangible asset other than goodwill recorded in connection with these acquisitions. The revenue and net income from these acquisitions, which are included in our consolidated statements of income, are not material.

In February 2013, Flo-gas Corporation purchased the propane operating assets of Glades Gas Co., Inc. for approximately \$2.7 million. The purchased assets are used to provide propane distribution service to approximately 3,000 residential and commercial customers in Okeechobee, Glades and Hendry Counties, Florida.

5. SEGMENT INFORMATION

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

Regulated Energy. The regulated energy segment includes natural gas distribution, natural gas transmission operations and electric distribution operations. All operations in this segment are regulated, as to their rates and services, by the PSCs having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.

Unregulated Energy. The unregulated energy segment includes propane distribution and wholesale marketing operations, and natural gas marketing operations, which are unregulated as to their rates and services.

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

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The following table presents information about our reportable segments.

For the Years Ended December 31, (in thousands)	2012	2011	2010
Operating Revenues, Unaffiliated Customers			
Regulated Energy	\$ 245,042	\$ 255,405	\$ 268,830
Unregulated Energy	130,020	149,586	146,430
Other	17,440	13,036	12,286
Total operating revenues, unaffiliated customers	\$ 392,502	\$ 418,027	\$ 427,546
Intersegment Revenues ⁽¹⁾			
Regulated Energy	\$ 1,166	\$ 1,368	\$ 1,104
Unregulated Energy	3,029		363
Other	917	793	856
Total intersegment revenues	\$ 5,112	\$ 2,161	\$ 2,323
Operating Income			
Regulated Energy	\$ 46,999	\$ 43,911	\$ 43,267
Unregulated Energy	8,355	9,619	8,150
Other	1,281	175	513
Operating Income	56,635	53,705	51,930
Other income	271	906	195
Interest charges	8,747	9,000	9,146
Income Before Income taxes	48,159	45,611	42,979
Income taxes	19,296	17,989	16,923
Net Income	\$ 28,863	\$ 27,622	\$ 26,056
Depreciation and Amortization			
Regulated Energy	\$ 18,653	\$ 16,512	\$ 14,680
Unregulated Energy	3,420	3,229	3,569
Other and eliminations	437	412	287
Total depreciation and amortization	\$ 22,510	\$ 20,153	\$ 18,536
Capital Expenditures			
Regulated Energy	\$ 69,056	\$ 37,104	\$ 41,898
Unregulated Energy	3,969	2,432	2,764
Other	5,185	4,895	2,293
Total capital expenditures	\$ 78,210	\$ 44,431	\$ 46,955

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

At December 31,	2012	2011
Identifiable Assets		
Regulated Energy	\$ 615,438	\$ 565,563
Unregulated Energy	79,287	107,916
Other	39,021	35,587
Total identifiable assets	\$ 733,746	\$ 709,066

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

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Cash paid for interest and income taxes during the years ended December 31, 2012, 2011 and 2010 were as follows:

For the Years Ended December 31, <i>(in thousands)</i>	2012	2011	2010
Cash paid for interest	\$ 8,086	\$ 7,746	\$ 8,134
Cash paid for income taxes	\$ 3,809	\$ 2,327	\$ 10,168

Non-cash investing and financing activities during the years ended December 31, 2012, 2011, and 2010 were as follows:

For the Years Ended December 31, <i>(in thousands)</i>	2012	2011	2010
Capital property and equipment acquired on account, but not paid as of December 31	\$ 6,192	\$ 938	\$ 1,064
Merger/acquisitions	\$	\$	\$ 300
Retirement Savings Plan	\$	\$ 80	\$ 902
Dividend Reinvestment Plan	\$	\$	\$ 1,182
Conversion of Debentures	\$ 186	\$ 181	\$ 202
Performance Incentive Plan	\$ 427	\$ 280	\$ 719
Director Stock Compensation Plan	\$ 443	\$ 456	\$ 297

7. DERIVATIVE INSTRUMENTS

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered normal purchases and sales and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory in order to mitigate the impact of wholesale price fluctuations. As of December 31, 2012, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Xeron, our propane wholesale and marketing subsidiary, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, the trading contracts are recorded at fair value, and the changes in fair value of those contracts are recognized as unrealized gains or losses in the consolidated statements of income in the period of change. As of December 31, 2012, we had the following outstanding trading contracts, which we accounted for as derivatives:

At December 31, 2012	Quantity in Gallons	Estimated Market Prices		Weighted Average Contract Prices
Forward Contracts				
Sale	1,262,000	\$ 0.7550	\$ 1.3650	\$ 0.9214
Purchase	2,648,000	\$ 0.7550	\$ 1.3300	\$ 0.9291

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

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

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In May 2012, our propane distribution operation entered into call options to protect against an increase in propane prices associated with 1,260,000 gallons purchased for the propane price cap program for the months of December 2012 through March 2013. The call options are exercised if propane prices rise above the strike prices, which range from \$0.905 per gallon to \$0.990 per gallon during this four-month period. We will receive the difference between the market price and the strike price during those months. We paid \$139,000 to purchase the call options and we accounted for the call options as a fair value hedge. As of December 31, 2012, the call options had a fair value of \$28,000. There was no ineffective portion of this fair value hedge in 2012.

In August 2011, our propane distribution operation entered into a put option to protect against the decline in propane prices and related potential inventory losses associated with 630,000 gallons purchased for the propane price cap program for the months of January through March 2012. This put option was exercised as propane prices fell below the strike price of \$1.445 per gallon in January through March of 2012. We received \$118,000, representing the difference between the market price and the strike price during those months. We had paid \$91,000 to purchase the put option, and we accounted for it as a fair value hedge.

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

Fair values of the derivative contracts recorded in the consolidated balance sheets as of December 31, 2012 and 2011, are as follows:

<i>(in thousands)</i>	Balance Sheet Location	Asset Derivatives	
		December 31, 2012	Fair Value December 31, 2011
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy assets	\$ 182	\$ 1,686
Derivatives designated as fair value hedges			
Put option ⁽¹⁾	Mark-to-market energy assets		68
Call option ⁽²⁾	Mark-to-market energy assets	28	
Total asset derivatives		\$ 210	\$ 1,754
Liability Derivatives			
<i>(in thousands)</i>	Balance Sheet Location	December 31, 2012	Fair Value December 31, 2011
Derivatives not designated as hedging instruments			
Forward contracts	Mark-to-market energy liabilities	\$ 331	\$ 1,496
Total liability derivatives		\$ 331	\$ 1,496

(1) We purchased a put option for the propane price cap program in August 2011. The put option was exercised in January through March of 2012 as the propane prices fell below the strike price of \$1.445 per gallon during this period.

(2) As a fair value hedge with no ineffective portion, the unrealized gains and losses associated with this call option are recorded in cost of sales, offset by the corresponding change in the value of propane inventory (hedged item), which is also recorded in cost of sales. The amounts in cost of sales offset to zero and the unrealized gains and losses of this call option effectively changed the value of propane inventory.

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The effects of gains and losses from derivative instruments are as follows:

<i>(in thousands)</i>	Location of Gain (Loss) on Derivatives	Amount of Gain (Loss) on Derivatives: For the Years Ended December 31,		
		2012	2011	2010
Derivatives designated as fair value hedges:				
Put Option	Cost of Sales	\$ 27	\$	\$
Put/Call Option ⁽¹⁾	Propane Inventory	(40)	(23)	
Derivatives not designated as hedging instruments:				
Put Option	Cost of Sales			(168)
Unrealized gain (loss) on forward contracts	Revenue	(339)	41	284
Total		(\$352)	\$ 18	\$ 116

⁽¹⁾ As a fair value hedge with no ineffective portion, the unrealized gains and losses associated with this put option are recorded in cost of sales, offset by the corresponding change in the value of propane inventory (hedged item), which is also recorded in cost of sales. The amounts in cost of sales offset to zero and the unrealized gains and losses of this put option effectively changed the value of propane inventory.

The effects of trading activities on the consolidated statements of income are as follows:

<i>(in thousands)</i>	Location of Gain (Loss) on Derivatives	Amount of Trading Revenue For the Years Ended December 31,		
		2012	2011	2010
Realized gain on forward contracts/put option	Revenue	\$ 2,695	\$ 2,215	\$ 1,540
Unrealized gain (loss) on forward contracts	Revenue	(339)	41	284
Total		\$ 2,356	\$ 2,256	\$ 1,824

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are the following:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities;

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability; and

Level 3: Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity).

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The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2012:

<i>(in thousands)</i>	Fair Value	Fair Value Measurements Using:		
		Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments equity securities	\$ 2,007	\$ 2,007	\$	\$
Investments other	\$ 2,161	\$ 2,161	\$	\$
Mark-to-market energy assets, including put option	\$ 210	\$	\$ 210	\$
Liabilities:				
Mark-to-market energy liabilities	\$ 331	\$	\$ 331	\$

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, 2011:

<i>(in thousands)</i>	Fair Value	Fair Value Measurements Using:		
		Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments equity securities	\$ 2,224	\$ 2,224	\$	\$
Investments other ⁽¹⁾	\$ 1,734	\$ 1,734	\$	\$
Mark-to-market energy assets, including put option	\$ 1,754	\$	\$ 1,754	\$
Liabilities:				
Mark-to-market energy liabilities	\$ 1,496	\$	\$ 1,496	\$

⁽¹⁾ The current portion of this investment (\$40) is included in other current assets in the accompanying consolidated balance sheets.

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The following valuation techniques were used to measure fair value assets in the tables above on a recurring basis as of December 31, 2012 and 2011:

Level 1 Fair Value Measurements:

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

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

Level 2 Fair Value Measurements:

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

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

At December 31, 2012, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

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

At December 31, 2012, long-term debt, which includes the current maturities of long-term debt, had a carrying value of \$110.1 million, compared to a fair value of \$133.2 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, with adjustments for duration, optionality and risk profile. At December 31, 2011, long-term debt, which includes the current maturities of long-term debt, had a carrying value of \$118.5 million, compared to a fair value of \$142.3 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

Note 15, Employee Benefit Plans, provides the fair value measurement information of our pension plan assets.

9. INVESTMENTS

The investment balances at December 31, 2012 and 2011, consist of the following:

<i>(in thousands)</i>	December 31, 2012	December 31, 2011
Rabbi trust (associated with Supplemental Executive Retirement Savings Plan)	\$ 2,116	\$ 1,624
Rabbi trust (associated with stay bonus of a former executive) ⁽¹⁾		40
Rabbi trust (associated with certain director s compensation)	39	
Investments in equity securities	2,013	2,294

Total	\$	4,168	\$	3,958
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⁽¹⁾ This investment is included in other current assets in the accompanying consolidated balance sheet. We classify these investments as trading securities and report them at their fair value. For the years ended December 31, 2012, 2011 and 2010, we recorded net unrealized gain of \$451,000, \$282,000 and \$181,000, respectively, in other income in the consolidated statements of income related to these investments. We also have recorded an associated liability, which is included in other pension and benefit costs in the consolidated balance sheets and is adjusted each month for the gains and losses incurred by the Rabbi Trusts.

Table of Contents**Notes to the Consolidated Financial Statements****10. GOODWILL AND OTHER INTANGIBLE ASSETS**

The carrying value of goodwill as of December 31, 2012 and 2011 was as follows:

<i>(in thousands)</i>	December 31, 2012	December 31, 2011
Regulated Energy	\$ 3,216	\$ 3,216
Unregulated Energy	874	874
Total	\$ 4,090	\$ 4,090

Goodwill in the regulated energy segment is comprised of approximately \$2.5 million from the FPU merger in October 2009 and \$746,000 from the purchase of operating assets from IGC in August 2010. Goodwill in the unregulated energy segment is comprised of \$200,000 from the purchase of the operating assets from Crescent in December 2011, and \$674,000 related to the premium paid by Sharp in its acquisitions in the late 1980s and 1990s.

We test for impairment of goodwill at least annually. The testing for 2012 and 2011 indicated no impairment of goodwill.

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2012 and 2011 are as follows:

<i>(in thousands)</i>	December 31, 2012		December 31, 2011	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Customer list	\$ 3,500	\$ 922	\$ 3,500	\$ 631
Other	566	346	566	308
Total	\$ 4,066	\$ 1,268	\$ 4,066	\$ 939

The customer list is an intangible asset, which was acquired in the FPU merger in October 2009 and is being amortized over a 12-year period. Other intangible assets include customer lists and a non-compete agreement acquired in the purchase of the operating assets of Virginia LP in February 2010 and customer lists and acquisition costs from our propane distribution acquisitions in the late 1980s and 1990s. These intangible assets are being amortized over a period ranging from seven to 40 years.

For the years ended December 31, 2012, 2011 and 2010, amortization expense of intangible assets was \$329,000, \$332,000 and \$679,000, respectively. Amortization expense of intangible assets is expected to be: \$325,000 for 2013 to 2016 and \$301,000 for 2017.

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Notes to the Consolidated Financial Statements

11. INCOME TAXES

We file a consolidated federal income tax return. Income tax expense allocated to our subsidiaries is based upon their respective taxable incomes and tax credits. FPU has been included in our consolidated federal return since the completion of the merger on October 28, 2009. State income tax returns are filed on a separate company basis in most states where we have operations and/or are required to file. FPU continues to file a separate state income tax return in Florida.

The Internal Revenue Service (IRS) performed its examination of FPU s consolidated federal returns for 2008 and for the period from January 1, 2009 to October 28, 2009 (the pre-merger period in 2009, during which FPU was required to file a separate federal tax return) and proposed a disallowance of approximately \$135,000 and \$256,000, respectively, of the environmental expenditure deductions taken by FPU related to one of the environmental remediation sites. We disagreed with the IRS finding and filed an appeal, which is currently underway. The IRS finding is based on the failure of FPU to follow a technical requirement to label these environmental expenditures in a specific way on the returns. At our request, the IRS granted relief in 2012, which allowed us to correctly label such expenditures for 2008 and 2009. We believe that those deductions will likely be sustained during the appeal process based on the IRS grant of such relief. Accordingly, we did not record any accrual as of December 31, 2012 and 2011, related to the examination by the IRS of the FPU returns.

The IRS performed its examination of Chesapeake s consolidated federal return for 2009. The IRS completed its examination in 2012 without any findings.

The State of Florida performed its examination of Chesapeake s state return for 2008, 2009 and 2010. The State of Florida completed its examination in 2012 without any material findings.

The State of Texas is currently performing its examination of Chesapeake s amended state tax return for 2007. We amended the 2007 Texas state tax return due to a change in the methodology used to calculate the gross receipts used to determine the Texas apportionment. This new methodology was used in Chesapeake s Texas tax returns for all years after 2006. In 2012, we recorded a total liability of \$300,000 associated with the unrecognized tax benefit related to this change in methodology given the unknown outcome of this examination. We recorded this liability associated with the unrecognized tax benefit as an income tax payable, which reduced the income tax receivable in the accompanying balance sheet at December 31, 2012.

We generated net operating losses of \$2.0 million in 2011 for federal income tax purposes, primarily from increased book-to-tax timing differences authorized by The Tax Relief Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which allowed bonus depreciation for certain assets. The federal net operating losses from 2011 are expected to be fully utilized upon the filing of our 2012 federal income tax return. None of the federal net operating losses from 2011 remained at December 31, 2012. We had previously generated net operating losses in 2008 for federal income tax purposes, which were carried forward to fully offset our taxable income in 2009 and partially offset our taxable income in 2010. None of the federal net operating losses from 2008 remained at December 31, 2012. We also had state net operating losses of \$28.1 million in various states as of December 31, 2012, almost all of which will expire in 2030. We have recorded a deferred tax asset of \$1.6 million and \$2.4 million related to the net operating loss carry-forwards at December 31, 2012 and 2011, respectively. We have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will be fully utilized.

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The following tables provide: (a) the components of income tax expense in 2012, 2011, and 2010; (b) the reconciliation between the statutory federal income tax rate and the effective income tax rate for 2012, 2011, and 2010; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2012 and 2011.

For the Years Ended December 31, (in thousands)	2012	2011	2010
Current Income Tax Expense			
Federal	\$ 3,483	\$ 0	\$ 1,566
State	1,990	742	2,116
Investment tax credit adjustments, net	(58)	(73)	(91)
Total current income tax expense	5,415	669	3,591
Deferred Income Tax Expense ⁽¹⁾			
Property, plant and equipment	14,301	16,885	16,964
Deferred gas costs	515	591	(2,505)
Pensions and other employee benefits	553	786	(402)
FPU merger related premium cost and deferred gain	(509)		(13)
Amortization of intangibles	80	17	(211)
Environmental expenditures	(82)	(65)	32
Net operating loss carryforwards	740	(1,000)	99
Reserve for insurance deductibles		18	(419)
Other	(1,717)	88	(213)
Total deferred income tax expense	13,881	17,320	13,332
Total Income Tax Expense	\$ 19,296	\$ 17,989	\$ 16,923
Reconciliation of Effective Income Tax Rates			
Continuing Operations			
Federal income tax expense (2)	\$ 16,745	\$ 16,146	\$ 15,053
State income taxes, net of federal benefit	2,659	2,216	2,083
Merger related costs			70
ESOP dividend deduction	(235)	(236)	(266)
Other	127	(137)	(17)
Total income tax expense	\$ 19,296	\$ 17,989	\$ 16,923
Effective income tax rate	40.07%	39.44%	39.38%

At December 31, (in thousands)	2012	2011
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	\$ 118,212	\$ 105,850
Acquisition adjustment	17,440	18,090
Deferred gas costs	816	301
Loss on reacquired debt	572	608

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Other	2,784	3,872
Total deferred income tax liabilities	139,824	128,721
Deferred income tax assets:		
Pension and other employee benefits	7,382	7,796
Environmental costs	1,917	1,835
Net operating loss carryforwards	1,587	2,401
Self insurance	484	452
Storm reserve liability	1,058	1,085
Other	2,982	2,240
Total deferred income tax assets	15,410	15,809
Deferred Income Taxes Per Consolidated Balance Sheet	\$ 124,414	\$ 112,912

- (1) Includes \$1,934,000, \$2,280,000, and \$1,963,000 of deferred state income taxes for the years 2012, 2011 and 2010, respectively.
- (2) Federal income taxes were recorded at 35% for each year represented.

Table of Contents**Notes to the Consolidated Financial Statements****12. LONG-TERM DEBT**

Our outstanding long-term debt is as shown below.

<i>(in thousands)</i>	December 31, 2012	December 31, 2011
FPU secured first mortgage bonds:		
9.57% bond, due May 1, 2018	\$ 5,444	\$ 6,348
10.03% bond, due May 1, 2018	2,994	3,492
9.08% bond, due June 1, 2022	7,962	7,958
Uncollateralized senior notes:		
7.83% note, due January 1, 2015	4,000	6,000
6.64% note, due October 31, 2017	13,636	16,363
5.50% note, due October 12, 2020	16,000	18,000
5.93% note, due October 31, 2023	30,000	30,000
5.68% note, due June 30, 2026	29,000	29,000
Convertible debentures:		
8.25% due March 1, 2014	942	1,134
Promissory note	125	186
 Total long-term debt	 110,103	 118,481
Less: current maturities	(8,196)	(8,196)
 Total long-term debt, net of current maturities	 \$ 101,907	 \$ 110,285

Annual maturities of consolidated long-term debt are as follows: \$8,196 for 2013; \$12,139 for 2014; \$9,141 for 2015; \$9,136 for 2016; \$12,037 for 2017; and \$59,510 thereafter.

Secured First Mortgage Bonds

FPU's secured first mortgage bonds are guaranteed by Chesapeake and are secured by a lien covering all of FPU's property. The 9.57 percent bond and 10.03 percent bond require annual sinking fund payments of \$909,000 and \$500,000, respectively.

Uncollateralized Senior Notes

On June 23, 2011, we issued \$29.0 million of 5.68 percent unsecured senior notes to Metropolitan Life Insurance Company and New England Life Insurance Company, pursuant to an agreement we entered into with them on June 29, 2010. These notes require annual principal payments of \$2.9 million beginning in the sixth year after the issuance. We used the proceeds to permanently finance the redemption of the 6.85 percent and 4.90 percent series of FPU first mortgage bonds. These redemptions occurred in January 2010 and were previously financed by Chesapeake's short-term loan facilities. Under the same agreement, we may issue an additional \$7.0 million of unsecured senior notes prior to May 3, 2013, at a rate ranging from 5.28 percent to 6.43 percent based on the timing of the issuance. These notes, if issued, will have similar covenants and default provisions as the senior notes issued in June 2011.

Convertible Debentures

The convertible debentures may be converted, at the option of the holder, into shares of our common stock at a conversion price of \$17.01 per share. During 2012 and 2011, debentures totaling \$187,000 and \$181,000, respectively, were converted to stock. The debentures are also redeemable for cash at the option of the holder, subject to an annual non-cumulative maximum limitation of \$200,000. In 2012 and 2011, debentures totaling \$5,000 and \$2,000, respectively, were redeemed for cash.

Table of Contents**Notes to the Consolidated Financial Statements***Debt Covenants*

Indentures to our long-term debt contain various restrictions. The most stringent restrictions state that we must maintain equity of at least 40 percent of total capitalization, and the fixed charge coverage ratio must be at least 1.2 times. In connection with the merger, the uncollateralized senior notes were amended to include an additional covenant requiring us to maintain no more than a 20-percent ratio of secured and subsidiary long-term debt to consolidated tangible net worth by October 2011. Failure to comply with those covenants could result in accelerated due dates and/or termination of the uncollateralized senior note agreements. As of December 31, 2012, we are in compliance with all of our debt covenants. With the redemption of FPU's 6.85 percent and 4.90 percent secured first mortgage bonds in January 2010, the additional covenant requiring us to maintain no more than a 20-percent ratio of secured and subsidiary long-term debt to consolidated tangible net worth was met.

Each of Chesapeake's uncollateralized senior notes contains a Restricted Payments covenant as defined in the note agreements. The most restrictive covenants of this type are included within the 7.83 percent Unsecured Senior Notes, due January 1, 2015. The covenant provides that we cannot pay or declare any dividends or make any other Restricted Payments in excess of the sum of \$10.0 million, plus our consolidated net income accrued on and after January 1, 2001. As of December 31, 2012, the cumulative consolidated net income base was \$185.3 million, offset by Restricted Payments of \$103.0 million, leaving \$82.3 million of cumulative net income free of restrictions.

Each series of FPU's first mortgage bonds contains a similar restriction that limits the payment of dividends by FPU. The most restrictive covenants of this type are included within the series that is due in 2022, which provides that FPU cannot make dividend or other restricted payments in excess of the sum of \$2.5 million plus FPU's consolidated net income accrued on and after January 1, 1992. As of December 31, 2012, FPU's cumulative net income base was \$85.1 million, offset by restricted payments of \$37.6 million, leaving \$47.5 million of cumulative net income for FPU free of restrictions pursuant to this covenant.

The dividend restrictions by FPU's first mortgage bonds resulted in approximately \$54.2 million of the net assets of our consolidated subsidiaries being restricted at December 31, 2012. This represents approximately 21 percent of our consolidated net assets. Other than the dividend restrictions by FPU's first mortgage bonds, there are no legal, contractual or regulatory restrictions on the net assets of our subsidiaries for the purposes of determining the disclosure of parent-only financial statements.

13. SHORT-TERM BORROWING

At December 31, 2012 and 2011, we had \$61.2 million and \$34.7 million, respectively, of short-term borrowings outstanding. The annual weighted average interest rates on our short-term borrowings were 1.48 percent and 1.53 percent for 2012 and 2011, respectively. We incurred commitment fees of \$73,000 and \$85,000 in 2012 and 2011, respectively.

The outstanding short-term borrowings at December 31, 2012 were composed of \$56.4 million in borrowings from bank lines of credit and \$4.8 million in book overdrafts, which if presented, would be funded through the bank lines of credit. The outstanding short-term borrowings at December 31, 2011 included \$30.5 million in borrowings from the bank lines of credit, and \$4.2 million in book overdrafts.

As of December 31, 2012, we had five unsecured bank credit facilities with two financial institutions, totaling \$140.0 million, none of which requires compensating balances. One of these facilities, for \$40.0 million, is a revolving credit note maturing on October 31, 2013. These bank lines are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of our capital expenditures. We maintain both committed and uncommitted credit facilities. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to \$100.0 million of short-term debt, as required, from these short-term lines of credit.

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Notes to the Consolidated Financial Statements

Committed Credit Facilities

As of December 31, 2012, we had two committed revolving credit facilities totaling \$60.0 million. The first facility is an unsecured \$30.0 million revolving line of credit that bears interest at the respective LIBOR rate, plus 1.25 percent per annum. At December 31, 2012, there was no borrowing capacity available under this credit facility.

The second facility is a \$30.0 million committed revolving line of credit that bears interest at a base rate plus 1.25 percent, if requested and advanced on the same day, or LIBOR for the applicable period plus 1.25 percent if requested three days prior to the advance date. At December 31, 2012, there was \$13.6 million available under this credit facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal year:

a funded indebtedness ratio of no greater than 65 percent; and

a fixed charge coverage ratio of at least 1.20 to 1.0.

We are in compliance with all of our debt covenants.

Uncommitted Credit Facilities

As of December 31, 2012, we had two uncommitted line of credit facilities totaling \$40.0 million. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks.

The first facility is an uncommitted \$20.0 million line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. At December 31, 2012, the entire borrowing capacity of \$20.0 million was available under this credit facility.

The second facility is a \$20.0 million uncommitted line of credit that bears interest at a rate per annum as offered by the bank for the applicable period. We have issued \$4.3 million in letters of credit under this credit facility. There have been no draws on these letters of credit as of December 31, 2012. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future. At December 31, 2012, there was \$15.7 million available under this credit facility, which is net of \$4.3 million for letters of credit issued.

In addition to the four unsecured bank lines of credit, we entered into a new, unsecured short-term credit facility for \$40.0 million with an existing lender on June 22, 2012. Short-term borrowings under this new facility bear interest at LIBOR plus 80 basis points or, at our discretion, the lender's base rate plus 80 basis points. This facility, which is structured in the form of a revolving credit note, matures on October 31, 2013. Our total short-term borrowing capacity available under this facility at December 31, 2012 was \$30.0 million.

14. LEASE OBLIGATIONS

We have entered into several operating lease arrangements for office space, equipment and pipeline facilities. Rent expense related to these leases for 2012, 2011 and 2010 was \$1.4 million, \$1.1 million and \$1.1 million, respectively. Future minimum payments under our current lease agreements for the years 2013 through 2017 are \$1.2 million, \$1.2 million, \$794,000, \$793,000 and \$420,000, respectively; and approximately \$3.1 million thereafter, with an aggregate total of approximately \$7.5 million.

15. EMPLOYEE BENEFIT PLANS

Retirement Plans

We sponsor a defined benefit pension plan (Chesapeake Pension Plan), an unfunded pension supplemental executive retirement plan (Chesapeake SERP), and an unfunded postretirement health care and life insurance plan (Chesapeake Postretirement Plan). As a result of the merger with FPU in October 2009, we now also sponsor and maintain a separate defined benefit pension plan for FPU (FPU Pension Plan) and a separate unfunded postretirement medical plan for FPU (FPU Medical Plan).

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We measure the assets and obligations of the defined benefit pension plans and other postretirement benefits plans to determine the plans' funded status as of the end of the year as an asset or a liability on our consolidated balance sheets. We record as a component of other comprehensive income/loss or a regulatory asset the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit costs.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated other comprehensive income/loss or as a regulatory asset as of December 31, 2012:

<i>(in thousands)</i>	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	(\$ 1)	\$	\$ 46	(\$986)	\$	(\$941)
Net loss	4,379	15,517	858	1,144	18	21,916
Total	\$ 4,378	\$ 15,517	\$ 904	\$ 158	\$ 18	\$ 20,975
Accumulated other comprehensive loss pre-tax ⁽¹⁾	\$ 4,378	\$ 2,948	\$ 904	\$ 158	\$ 3	\$ 8,391
Post-merger regulatory asset		12,569			15	12,584
Subtotal	4,378	15,517	904	158	18	20,975
Pre-merger regulatory asset		5,109			62	5,171
Total unrecognized cost	\$ 4,378	\$ 20,626	\$ 904	\$ 158	\$ 80	\$ 26,146

⁽¹⁾ The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheet as of December 31, 2012 is net of income tax benefits of \$3.3 million.

The pre-merger regulatory asset of \$5.2 million at December 31, 2012 represents the portion attributable to FPU's regulated energy operations of the changes in the funded status in the FPU Pension Plan and FPU Medical Plan that occurred but were not recognized, as part of the net periodic benefit costs prior to the merger. This portion was deferred as a regulatory asset prior to the merger by FPU pursuant to a previous order by the Florida PSC and continues to be amortized over the remaining service period of the participants at the time of the merger.

During 2012 and 2011, we experienced a significant decline in interest and other corporate bond rates, and as a result, we used lower discount rates for our pension and other postretirement plans at December 31, 2012 and 2011 to estimate the benefit obligations of those plans. We also experienced a decline in plan asset values during 2011, which, in conjunction with the higher benefit obligations, resulted in higher unrecognized costs at December 31, 2012 and 2011. The total unrecognized cost of our pension and postretirement benefits plans was \$26.1 million and \$23.1 million at December 31, 2012 and 2011, respectively, compared to \$13.9 million at December 31, 2010.

The amounts in accumulated other comprehensive income/loss and regulatory asset for our pension and postretirement benefits plans that are expected to be recognized as a component of net benefit cost in 2013 are set forth in the following table:

<i>(in thousands)</i>	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	(\$1)	\$	\$ 19	(\$77)	\$	(\$59)
Net loss	\$ 308	\$ 332	\$ 64	\$ 74	\$	\$ 778
Amortization of pre-merger regulatory asset	\$	\$ 761	\$	\$	\$ 8	\$ 769

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In March 2011, new plan provisions for the FPU Medical Plan were adopted in a continuing effort to standardize FPU's benefits with those offered by Chesapeake. The new plan provisions, which became effective January 1, 2012, require eligible employees retiring in 2012 through 2014 to pay a portion of the total benefit costs based on the year they retire. Participants retiring in 2015 and after will be required to pay the full benefit costs associated with participation in the FPU Medical Plan. The change in the FPU Medical Plan resulted in a curtailment gain of \$892,000. We recorded \$170,000 of this curtailment gain, which was allocated to FPU's unregulated operations, in 2012. We deferred \$722,000 of this curtailment gain and included it as a regulatory liability at December 31, 2012. The deferred portion of our curtailment gain was associated with FPU's regulated operations. Since we determined that the non-recurring gain resulted from the FPU merger and the related integration, we determined that the appropriate accounting treatment prescribed deferral and amortization over a future period, as specified by the Florida PSC.

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In January 2011, a former executive officer retired and received lump-sum pension distributions of \$844,000 and \$765,000 from the Chesapeake Pension Plan and Chesapeake SERP, respectively. In connection with these lump-sum payment distributions, we recorded \$436,000 in pension settlement losses in addition to the net benefit cost in 2011. Based upon the current funding status of the Chesapeake Pension Plan, which does not meet or exceed 110 percent of the benefit obligation as required per the Department of Labor regulations, our former executive officer was required to deposit property equal to 125 percent of the restricted portion of his lump sum distribution into an escrow. Each year, an amount equal to the value of payments that would have been paid to him if he had elected the life annuity form of distribution will become unrestricted. Property equal to the life annuity amount will be returned to him from the escrow account. These same regulations will apply to the top 20 highest compensated employees taking distributions from the Pension Plan.

Defined Benefit Pension Plans

The Chesapeake Pension Plan was closed to new participants effective January 1, 1999, and was frozen with respect to additional years of service and additional compensation effective January 1, 2005. Benefits under the Chesapeake Pension Plan were based on each participant's years of service and highest average compensation, prior to the freezing of the plan.

The FPU Pension Plan covers eligible FPU non-union employees hired before January 1, 2005 and union employees hired before the respective union contract expiration dates in 2005 and 2006. Prior to the merger, the FPU Pension Plan was frozen with respect to additional years of service and additional compensation effective December 31, 2009.

Our funding policy provides that payments to the trustee of each plan shall be equal to at least the minimum funding requirements of the Employee Retirement Income Security Act of 1974. The following schedule summarizes the assets of the Chesapeake Pension Plan and the FPU Pension Plan, by investment type, at December 31, 2012, 2011 and 2010:

At December 31, Asset Category	Chesapeake Pension Plan			FPU Pension Plan		
	2012	2011	2010	2012	2011	2010
Equity securities	52.07%	51.75%	64.33%	52.81%	51.98%	60.00%
Debt securities	38.00%	37.88%	30.60%	38.04%	38.05%	35.00%
Other	9.93%	10.37%	5.07%	9.15%	9.97%	5.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

In December 2011, we changed the investments and investment asset allocation of our pension assets to better align them with the investment goals and objectives established for the Plans. This change also resulted in the pension assets of the Chesapeake Pension Plan and FPU Pension Plan being invested in similar investments. The investment policy of both the Chesapeake and FPU Pension Plans is designed to provide the capital assets necessary to meet the financial obligations of the plans. The investment goals and objectives are to achieve investment returns that together with contributions will provide funds adequate to pay promised benefits to present and future beneficiaries of the plans, earn a long-term investment return in excess of the growth of the Plans' retirement liabilities, minimize pension expense and cumulative contributions resulting from liability measurement and asset performance, and maintain a diversified portfolio to reduce the risk of large losses.

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On June 29, 2012, the United States Congress passed the Moving Ahead for Progress in the 21st Century Act (also known as the Transportation and Student Loan Bill). Included in this legislation was pension funding relief, which allows pension sponsors to use 25-year average corporate bond rates rather than current interest rates to measure pension obligations for pension funding purposes. Although this legislation does not affect the accounting treatment of pension plans, the allowed use of higher interest rates to measure pension plan obligations for funding purposes reduces the minimum pension plan contribution requirements. Despite the reduction in the minimum pension plan contribution requirements, we made 2012 pension plan contributions at levels similar to those we had initially estimated prior to the passage of the legislation. This represented minimum contribution payments using the current interest rates to measure pension plan obligations as well as additional contributions to achieve a certain level of funding in those plans.

The following allocation range of asset classes is intended to produce a rate of return sufficient to meet the Plans' goals and objectives:

Asset Class	Minimum Allocation Percentage	Maximum Allocation Percentage
Domestic Equities (Large Cap, Mid Cap and Small Cap)	14%	32%
Foreign Equities (Developed and Emerging Markets)	13%	25%
Fixed Income (Inflation Bond and Taxable Fixed)	26%	40%
Alternative Strategies (Long/Short Equity and Hedge Fund of Funds)	6%	14%
Diversifying Assets (High Yield Fixed Income, Commodities, and Real Estate)	7%	19%
Cash	0%	5%

Due to periodic contributions and different asset classes producing varying returns, the actual asset values may temporarily move outside of the intended ranges. The investments are monitored on a quarterly basis, at a minimum, for asset allocation and performance.

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At December 31, 2012, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

Asset Category (in thousands)	Fair Value Measurement Hierarchy			Total
	Level 1	Level 2	Level 3	
Equity securities				
U.S. Large Cap ⁽¹⁾	\$ 3,504	\$ 3,443	\$	\$ 6,947
U.S. Mid Cap ⁽¹⁾		3,078		3,078
U.S. Small Cap ⁽¹⁾		1,523		1,523
International ⁽²⁾	10,019			10,019
Alternative Strategies ⁽³⁾	4,978			4,978
	18,501	8,044		26,545
Debt securities				
Inflation Protected ⁽⁴⁾	2,507			2,507
Fixed income ⁽⁵⁾		14,109		14,109
High Yield ⁽⁵⁾		2,547		2,547
	2,507	16,656		19,163
Other				
Commodities ⁽⁶⁾	1,918			1,918
Real Estate ⁽⁷⁾	2,048			2,048
Guaranteed deposit ⁽⁸⁾			710	710
	3,966		710	4,676
Total Pension Plan Assets	\$ 24,974	\$ 24,700	\$ 710	\$ 50,384

(1) Includes funds that invest primarily in United States common stocks.

(2) Includes funds that invest primarily in foreign equities and emerging markets equities.

(3) Includes funds that actively invest in both equity and debt securities, funds that sell short securities and funds that provide long-term capital appreciation. The funds may invest in debt securities below investment grade.

(4) Includes funds that invest primarily in inflation-indexed bonds issued by the U.S. government.

(5) Includes funds that invest in investment grade and fixed income securities.

(6) Includes funds that invest primarily in commodity-linked derivative instruments and fixed income securities.

(7) Includes funds that invest primarily in real estate.

(8) Includes investment in a group annuity product issued by an insurance company.

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At December 31, 2011, the assets of the Chesapeake Pension Plan and the FPU Pension Plan were comprised of the following investments:

Asset Category (in thousands)	Fair Value Measurement Hierarchy			Total
	Level 1	Level 2	Level 3	
Equity securities				
U.S. Large Cap ⁽¹⁾	\$ 3,146	\$ 3,151	\$	\$ 6,297
U.S. Mid Cap ⁽¹⁾		2,683		2,683
U.S. Small Cap ⁽¹⁾		1,341		1,341
International ⁽²⁾	8,563			8,563
Alternative Strategies ⁽³⁾	4,489			4,489
	16,198	7,175		23,373
Debt securities				
Inflation Protected ⁽⁴⁾	2,237			2,237
Fixed income ⁽⁵⁾		12,617		12,617
High Yield ⁽⁵⁾		2,256		2,256
	2,237	14,873		17,110
Other				
Commodities ⁽⁶⁾	1,789			1,789
Real Estate ⁽⁷⁾	1,797			1,797
Guaranteed deposit ⁽⁸⁾			897	897
Other	32			32
	3,618		897	4,515
Total Pension Plan Assets	\$ 22,053	\$ 22,048	\$ 897	\$ 44,998

(1) Includes funds that invest primarily in United States common stocks.

(2) Includes funds that invest primarily in foreign equities and emerging markets equities.

(3) Includes funds that actively invest in both equity and debt securities, funds that sell short securities and funds that provide long-term capital appreciation. The funds may invest in debt securities below investment grade.

(4) Includes funds that invest primarily in inflation-indexed bonds issued by the U.S. government.

(5) Includes funds that invest in investment grade and fixed income securities.

(6) Includes funds that invest primarily in commodity-linked derivative instruments and fixed income securities.

(7) Includes funds that invest primarily in real estate.

(8) Includes investment in a group annuity product issued by an insurance company.

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At December 31, 2012 and 2011, all of the investments classified under Level 1 of the fair value measurement hierarchy were recorded at fair value based on unadjusted quoted prices in active markets for identical investments. The Level 2 investments were recorded at fair value based on net asset value per unit of the investments, which used significant observable inputs although those investments were not traded publicly and did not have quoted market prices in active markets. The Level 3 investments were guaranteed deposit accounts, which were valued based on the liquidation value of those accounts, including the effect of the balance and interest guarantee and liquidation restriction.

The following table sets forth the summary of the changes in the fair value of Level 3 investments for the years ended December 31, 2012 and 2011:

At December 31, <i>(in thousands)</i>	2012	2011
Balance, beginning of year	\$ 897	\$
Purchases	79	897
Transfers in	3,620	
Disbursements	(3,902)	
Investment Income	16	
Balance, end of year	\$ 710	\$ 897

Table of Contents**Notes to the Consolidated Financial Statements**

The following schedule sets forth the funded status at December 31, 2012 and 2011:

At December 31, (in thousands)	Chesapeake Pension Plan		FPU Pension Plan	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation beginning of year	\$ 11,672	\$ 11,760	\$ 57,999	\$ 52,478
Interest cost	458	520	2,577	2,695
Actuarial loss	726	941	6,915	5,403
Benefits paid	(923)	(705)	(2,979)	(2,577)
Effect of settlement		(844)		
Benefit obligation end of year	11,933	11,672	64,512	57,999
Change in plan assets:				
Fair value of plan assets beginning of year	7,162	7,787	37,836	40,201
Actual return on plan assets	849	(124)	4,526	(1,101)
Employer contributions	1,342	1,048	2,571	1,313
Benefits paid	(923)	(705)	(2,979)	(2,577)
Effect of settlement		(844)		
Fair value of plan assets end of year	8,430	7,162	41,954	37,836
Reconciliation:				
Funded status	(3,503)	(4,510)	(22,558)	(20,163)
Accrued pension cost	(3,503)	(4,510)	(22,558)	(20,163)
Assumptions:				
Discount rate	3.50%	4.25%	3.75%	4.50%
Expected return on plan assets	6.00%	6.00%	7.00%	7.00%

Net periodic pension cost (benefit) for the plans for 2012, 2011 and 2010 include the components shown below:

For the Years Ended December 31, (in thousands)	Chesapeake Pension Plan			FPU Pension Plan		
	2012	2011	2010	2012	2011	2010
Components of net periodic pension cost:						
Interest cost	\$ 458	\$ 520	\$ 570	\$ 2,577	\$ 2,695	\$ 2,729
Expected return on assets	(418)	(424)	(423)	(2,627)	(2,783)	(2,532)
Amortization of prior service cost	(5)	(5)	(5)			
Amortization of actuarial loss	255	156	155	196		
Net periodic pension cost	290	247	297	146	(88)	197
Settlement expense		217				

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Amortization of pre-merger regulatory asset				761	761	888
Total periodic cost	\$ 290	\$ 464	\$ 297	\$ 907	\$ 673	\$ 1,085
Assumptions:						
Discount rate	4.25%	5.00%	5.25%	4.50%	5.25%	5.75%
Expected return on plan assets	6.00%	6.00%	6.00%	7.00%	7.00%	7.00%

Table of Contents**Notes to the Consolidated Financial Statements*****Pension Supplemental Executive Retirement Plan***

The Chesapeake SERP was frozen with respect to additional years of service and additional compensation as of December 31, 2004. Benefits under the Chesapeake SERP were based on each participant's years of service and highest average compensation, prior to the freezing of the plan. The accumulated benefit obligation for the Chesapeake SERP, which is unfunded, was \$2.4 million and \$2.2 million, at December 31, 2012 and 2011, respectively.

At December 31, <i>(in thousands)</i>	2012	2011
Change in benefit obligation:		
Benefit obligation beginning of year	\$ 2,160	\$ 2,731
Interest cost	90	107
Actuarial loss	191	176
Benefits paid	(89)	(89)
Effect of settlement		(765)
Benefit obligation end of year	2,352	2,160
Change in plan assets:		
Fair value of plan assets beginning of year		
Employer contributions	89	854
Benefits paid	(89)	(89)
Effect of settlement		(765)
Fair value of plan assets end of year		
Reconciliation:		
Funded status	(2,352)	(2,160)
Accrued pension cost	(\$2,352)	(\$2,160)
Assumptions:		
Discount rate	3.50%	4.25%

Net periodic pension costs for the Chesapeake SERP for 2012, 2011, and 2010 include the components shown below:

For the Years Ended December 31, <i>(in thousands)</i>	2012	2011	2010
Components of net periodic pension cost:			
Interest cost	\$ 90	\$ 107	\$ 136
Amortization of prior service cost	19	19	18
Amortization of actuarial loss	46	38	59
Net periodic pension cost	155	164	213
Settlement expense		219	
Total periodic cost	\$ 155	\$ 383	\$ 213

Assumptions:

Discount rate	4.25%	5.00%	5.25%
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Table of Contents**Notes to the Consolidated Financial Statements****Other Postretirement Benefits Plans**

The following schedule sets forth the status of other postretirement benefit plans:

At December 31, (in thousands)	Chesapeake Postretirement Plan		FPU Medical Plan	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation beginning of year	\$ 1,396	\$ 2,474	\$ 4,081	\$ 3,098
Service cost			1	125
Interest cost	55	64	79	176
Plan amendments		(1,140)		
Plan participants contributions	111	108	92	88
Curtailment gain			(2,651)	
Actuarial loss	39	100	500	802
Benefits paid	(186)	(210)	(328)	(208)
Benefit obligation end of year	1,415	1,396	1,774	4,081
Change in plan assets:				
Fair value of plan assets beginning of year				
Employer contributions ⁽¹⁾	75	102	236	120
Plan participants contributions	111	108	92	88
Benefits paid	(186)	(210)	(328)	(208)
Fair value of plan assets end of year				
Reconciliation:				
Funded status	(1,415)	(1,396)	(1,774)	(4,081)
Accrued postretirement cost	(\$1,415)	(\$1,396)	(\$1,774)	(\$4,081)
Assumptions:				
Discount rate	3.50%	4.25%	3.75%	4.50%

⁽¹⁾ Chesapeake's Postretirement Plan does not receive a Medicare Part-D subsidy. The FPU Medical Plan did not receive a significant subsidy for the post-merger period.

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Net periodic postretirement benefit costs for 2012, 2011, and 2010 include the following components:

For the Years Ended December 31, (in thousands)	Chesapeake Postretirement Plan			FPU Medical Plan		
	2012	2011	2010	2012	2011	2010
Components of net periodic postretirement cost:						
Service cost	\$	\$	\$	\$ 1	\$ 125	\$ 76
Interest cost	55	64	122	79	176	123
Amortization of:						
Actuarial (gain) loss	73	67	57		55	(6)
Prior service cost	(77)	(77)				
Net periodic postretirement cost	\$ 51	\$ 54	\$ 179	\$ 80	\$ 356	\$ 193
Curtailment gain				(892)		
Net periodic postretirement cost	\$ 51	\$ 54	\$ 179	(\$812)	\$ 356	\$ 193
Assumptions						
Discount rate	4.25%	5.00%	5.25%	4.50%	5.25%	5.75%

In addition, we recorded an expense of \$8,000 in 2012 and 2011, and \$9,000 in 2010, related to continued amortization of FPU's pre-merger postretirement benefit regulatory asset.

Assumptions

The assumptions used for the discount rate to calculate the benefit obligations of all the plans were based on the interest rates of high-quality bonds in 2012, reflecting the expected lives of the plans. In determining the average expected return on plan assets for each applicable plan, various factors, such as historical long-term return experience, investment policy and current and expected allocation, were considered. Since Chesapeake's plans and FPU's plans have different expected plan lives and investment policies, particularly in light of the lump-sum-payment option provided in the Chesapeake Pension Plan, different assumptions regarding discount rate and expected return on plan assets were selected for Chesapeake's plans and FPU's plans. Since both pension plans are frozen with respect to additional years of service and compensation, the rate of assumed compensation increases is not applicable.

The health care inflation rate for 2012 used to calculate the benefit obligation is 6.0 percent for medical and 7.0 percent for prescription drugs for the Chesapeake Postretirement Plan; and 7.5 percent for the FPU Medical Plan. A one percentage point increase in the health care inflation rate from the assumed rate would increase the accumulated postretirement benefit obligation by approximately \$255,000 as of December 31, 2012, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2012 by approximately \$11,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately \$222,000 as of December 31, 2012, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2012 by approximately \$10,000.

Table of Contents**Notes to the Consolidated Financial Statements*****Estimated Future Benefit Payments***

In 2013, we expect to contribute \$325,000 and \$650,000 to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and \$88,000 to the Chesapeake SERP. We also expect to contribute \$97,000 and \$258,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2013. The schedule below shows the estimated future benefit payments for each of the plans previously described:

	Chesapeake Pension Plan ⁽¹⁾	FPU Pension Plan ⁽¹⁾	Chesapeake SERP ⁽²⁾	Chesapeake Postretirement Plan ⁽²⁾	FPU Medical Plan ⁽²⁾
<i>(in thousands)</i>					
2013	\$ 564	\$ 2,816	\$ 88	\$ 97	\$ 258
2014	\$ 496	\$ 2,881	\$ 86	\$ 99	\$ 241
2015	\$ 628	\$ 2,930	\$ 136	\$ 101	\$ 221
2016	\$ 576	\$ 2,974	\$ 143	\$ 98	\$ 183
2017	\$ 1,194	\$ 3,006	\$ 141	\$ 97	\$ 147
Years 2018 through 2022	\$ 3,945	\$ 16,037	\$ 654	\$ 451	\$ 441

⁽¹⁾ The pension plan is funded; therefore, benefit payments are expected to be paid out of the plan assets.

⁽²⁾ Benefit payments are expected to be paid out of our general funds.

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 and determined that the deferred tax effects were not material to our financial results.

Retirement Savings Plan

Effective January 1, 2012, we sponsor one 401(k) retirement savings plan and one non-qualified supplemental employee retirement savings plan.

Our 401(k) plan is offered to all eligible employees who have completed three months of service, except for employees represented by a collective bargaining agreement that does not specifically provide for participation in the plan, non-resident aliens with no U.S. source income and individuals classified as consultants, independent contractors or leased employees. Effective January 1, 2011, we match 100 percent of eligible participants' pre-tax contributions to the Chesapeake 401(k) plan up to a maximum of six percent of eligible compensation, including pre-tax contributions made by BravePoint employees. In addition, we may make a supplemental contribution to participants in the plan, without regard to whether or not they make pre-tax contributions. Beginning January 1, 2011, the employer matching contribution is made in cash and is invested based on a participant's investment directions. Any supplemental employer contribution is generally made in Chesapeake stock. With respect to the employer match and supplemental employer contribution, employees are 100 percent vested after two years of service or upon reaching 55 years of age while still employed by Chesapeake. Employees with one year of service are 20 percent vested and will become 100 percent vested after two years of service. Employees who do not make an election to contribute or do not opt out of the Chesapeake 401(k) plan will be automatically enrolled at a deferral rate of three percent, and the automatic deferral rate will increase by one percent per year up to a maximum of six percent.

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Effective January 1, 1999, we began offering a non-qualified supplemental employee retirement savings plan (401(k) SERP) to our executive officers over a specific income threshold. Participants receive a cash-only matching contribution percentage equivalent to their 401(k) match level. All contributions and matched funds can be invested among the mutual funds available for investment. All obligations arising under the 401(k) SERP are payable from our general assets, although we have established a Rabbi Trust for the 401(k) SERP. Assets held in the Rabbi Trust for the 401(k) SERP had a fair value of \$2.2 million and \$1.7 million at December 31, 2012 and 2011, respectively. (See Note 9, Investments, for further details). The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Prior to January 1, 2012, we sponsored two separate 401(k) retirement savings plans, one for FPU employees and the second covering all other Chesapeake employees. From January 1, 2011 to December 31, 2011, benefits offered under the two separate 401(k) retirement savings plans were substantially the same. Those benefits were also similar to the benefits offered under the one combined 401(k) retirement savings plan, effective January 1, 2012.

Prior to January 1, 2011, FPU's 401(k) plan provided a matching contribution of 50 percent of an employee's pre-tax contributions, up to six percent of the employee's salary, for a maximum company contribution of up to three percent. For non-union employees the plan provided a company match of 100 percent for the first two percent of an employee's contribution, and a match of 50 percent for the next four percent of an employee's contribution, for a total company match of up to four percent. Employees were automatically enrolled at the three percent contribution level, with the flexibility of opting out, and were eligible for the company match after six months of continuous service, with vesting of 100 percent after three years of continuous service.

Prior to January 1, 2011, we made matching contributions up to six percent of the employee's eligible pre-tax compensation for Chesapeake legacy businesses, except for BravePoint, as further explained below. The match was between 100 percent and 200 percent of the employee's contribution (up to six percent of eligible compensation), based on the employee's age and years of service. The first 100 percent was matched with Chesapeake common stock; the remaining match was invested in Chesapeake's 401(k) Plan according to each employee's investment direction. Employees were automatically enrolled at a two-percent contribution, with the flexibility of opting out, and were eligible for the company match after three months of continuing service, with vesting of 20 percent per year.

From July 1, 2006 to December 31, 2010, our contribution made on behalf of BravePoint employees was a 50 percent matching contribution, for up to six percent of each employee's annual compensation contributed to the plan. The matching contribution was funded in Chesapeake common stock. The plan was also amended at the same time to enable it to receive discretionary profit-sharing contributions in the form of employee pre-tax deferrals. The extent to which BravePoint had funds available for profit-sharing was dependent upon the extent to which the segment's actual earnings exceeded budgeted earnings. Any profit-sharing dollars made available to employees could be deferred into the plan and/or paid out in the form of a bonus.

Contributions to all of our 401(k) plans totaled \$2.9 million for the year ended December 31, 2012, \$2.7 million for the year ended December 31, 2011, and \$1.7 million for the year ended December 31, 2010. As of December 31, 2012, there are 580,484 shares reserved to fund future contributions to the 401(k) plans.

Deferred Compensation Plan

On December 7, 2006, the Board of Directors approved the Chesapeake Utilities Corporation Deferred Compensation Plan (Deferred Compensation Plan), as amended, effective January 1, 2007. The Deferred Compensation Plan is a non-qualified, deferred compensation arrangement under which certain executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors' retainers and fees. At December 31, 2012, the Deferred Compensation Plan consisted solely of shares of common stock related to the deferral of executive performance shares and directors' stock retainers.

Participants in the Deferred Compensation Plan are able to elect the payment of benefits to begin on a specified future date after the election is made in the form of a lump sum or annual installments. Deferrals of executive cash bonuses and directors' cash retainers and fees are paid in cash. All deferrals of executive performance shares, which represent deferred stock units, and directors' stock retainers are paid in shares of our common stock, except that cash is paid in lieu of fractional shares.

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We established a Rabbi Trust in connection with the Deferred Compensation Plan. The value of our stock held in the Rabbi Trust is classified within the stockholders' equity section of the Balance Sheet and has been accounted for in a manner similar to treasury stock. The amounts recorded under the Deferred Compensation Plan totaled \$982,000 and \$817,000 at December 31, 2012 and 2011, respectively.

Table of Contents**Notes to the Consolidated Financial Statements****16. SHARE-BASED COMPENSATION PLANS**

Our non-employee directors and key employees are awarded share-based awards through our Directors Stock Compensation Plan (DSCP) and our Performance Incentive Plan (PIP), respectively. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period.

The table below presents the amounts included in net income related to share-based compensation expense for the awards granted under the DSCP and the PIP for the years ended December 31, 2012, 2011 and 2010:

For the Years Ended December 31, <i>(in thousands)</i>	2012	2011	2010
Directors Stock Compensation Plan	\$ 443	\$ 407	\$ 283
Performance Incentive Plan	976	1,043	872
Total compensation expense	1,419	1,450	1,155
Less: tax benefit	569	581	463
Share-Based Compensation amounts included in net income	\$ 850	\$ 869	\$ 692

Stock Options

We did not have any stock options outstanding at December 31, 2012 or 2011, nor were any stock options issued during 2012, 2011 and 2010.

Directors Stock Compensation Plan

Shares granted under the DSCP are issued in advance of the directors' service periods and are fully vested as of the date of the grant. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2012, each of our non-employee directors received an annual retainer of 900 shares of common stock under the DSCP.

A summary of stock activity under the DSCP for the years ended December 31, 2012, 2011 and 2010 is presented below.

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding December 31, 2010		
Granted ⁽¹⁾	11,104	\$ 41.02
Vested	11,104	\$ 41.02
Forfeited		
Outstanding December 31, 2011		
Granted	10,800	\$ 41.06
Vested	10,800	\$ 41.06
Forfeited		

Outstanding December 31, 2012

⁽¹⁾ In January 2011, our former Chief Executive Officer retired from the Company and was awarded 304 shares of common stock for the prorated portion of his service period as he began his service as a non-executive board member. The weighted average grant date fair value of DSCP shares awarded during 2012 and 2011 was \$41.06 and \$41.02, per share, respectively. The intrinsic values of the DSCP awards are equal to the fair value of these awards on the date of grant. At December 31, 2012, there was \$148,000 of unrecognized compensation expense related to DSCP awards that is expected to be recognized over the first four months of 2013.

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As of December 31, 2012, there were 12,311 shares reserved for issuance under the DSCP.

Performance Incentive Plan

Our Compensation Committee is authorized to grant key employees of the Company the right to receive awards of shares of our common stock, contingent upon the achievement of established performance goals. These awards are subject to certain post-vesting transfer restrictions.

We currently have multi-year performance plans, which are earned based upon the successful achievement of long-term goals, growth and financial results, which comprised both market-based and performance-based conditions or targets. The fair value of each share of stock tied to a performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each share of market-based award granted.

In July 2012, we replaced a subsidiary officer's multi-year cash-based incentive award with an award of 4,800 shares under the PIP. These shares will vest at the end of the service period ending December 31, 2014 and have terms and market/performance targets similar to other shares granted under the PIP in January 2012.

Effective February 24, 2012, one of our named executive officers, who was a participant in the PIP, resigned. Pursuant to a separation agreement entered into between the Company and the named executive officer, the named executive officer received a cash payment of \$181,500 and other benefits in lieu of other performance-based compensation, which he might have been entitled to receive.

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

A summary of stock activity under the PIP is presented below:

		Number of Shares	Weighted Average Fair Value
Outstanding	December 31, 2010	101,150	\$ 28.78
Granted		41,664	\$ 40.16
Vested		31,400	\$ 27.63
Forfeited		24,000	\$ 29.31
Expired			
Outstanding	December 31, 2011	87,414	\$ 34.47
Granted		35,706	\$ 39.62
Vested		13,837	\$ 29.19
Forfeited ⁽¹⁾		21,600	\$ 36.57
Expired		3,038	\$ 26.29
Outstanding	December 31, 2012	84,645	\$ 37.86

⁽¹⁾ Includes shares settled with a cash payment pursuant to the terms of a separation agreement with a former named executive officer.

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In 2012, 2011 and 2010, we withheld shares with value at least equivalent to the employees' minimum statutory obligation for the applicable income and other employment taxes, and remitted the cash to the appropriate taxing authorities with the executives receiving the net shares. The total number of shares withheld of 5,670, 12,324 and 17,695 for 2012, 2011 and 2010, respectively, was based on the value of the PIP shares on their vesting date, determined by the average of the high and low of our stock price. Total payments for the employees' tax obligations to the taxing authorities were approximately \$238,000, \$496,000, and \$538,000 in 2012, 2011 and 2010, respectively.

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The weighted average grant-date fair value of PIP awards granted during 2012, 2011 and 2010 was \$39.62, \$40.16 and \$29.38, per share, respectively. The intrinsic value of the PIP awards was \$1.2 million, \$1.9 million and \$2.7 million for 2012, 2011 and 2010, respectively.

As of December 31, 2012, there were 317,785 shares reserved for issuance under the PIP.

17. RATES AND OTHER REGULATORY ACTIVITIES

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC. Chesapeake's Florida natural gas distribution division and FPU's natural gas and electric operations continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

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

- (i) a monthly fixed charge to customers in portions of eastern Sussex County, Delaware, which will enable the Delaware division to extend its distribution system to provide natural gas service to these customers economically without upfront contributions from these customers;
- (ii) optional service offerings to customers to assist them in conversions, including a conversion finance service to assist customers with their cost of conversion equipment; and
- (iii) a slight rate increase for all Delaware customers in order to support the additional costs associated with the administration and implementation of the proposed service offerings.

On July 3, 2012, the Delaware PSC officially opened the docket and set a period for formal interventions to be filed. On January 4, 2013, the Division of the Public Advocate filed a motion to close the docket on the grounds that the proposed expansion service offerings should only be considered in the context of a full base rate case. On February 6, 2013, the Hearing Examiner assigned to the case issued a report recommending that the Delaware PSC deny the Division of Public Advocate's motion. We anticipate that the Delaware PSC will render a decision on the Division of the Public Advocate's motion in the first quarter of 2013. If the motion is denied, we anticipate that the Delaware PSC will render a final decision on the expansion service application in the second quarter of 2013.

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

On September 1, 2011, the Delaware division filed with the Delaware PSC its annual Gas Service Rates (GSR) application, seeking approval to change its GSR, effective November 1, 2011. On September 20, 2011, the Delaware PSC authorized the Delaware division to implement the GSR charges, as filed on November 1, 2011, on a temporary basis. The Delaware PSC granted approval of the GSR charges at its regularly scheduled meeting on July 17, 2012.

On June 18, 2012, the Delaware division filed an application with the Delaware PSC requesting approval for a Town of Selbyville franchise fee rider. This rider allows the Delaware division to charge all natural gas customers within the town limits the franchise fee paid by the Delaware division to the Town of Selbyville as a condition to providing natural gas service. The Delaware PSC granted approval of this franchise fee rider on August 7, 2012.

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On September 21, 2012, the Delaware division filed with the Delaware PSC its annual GSR application, seeking approval to change its GSR, effective November 1, 2012. On October 9, 2012, the Delaware PSC authorized the Delaware division to implement the GSR charges, as filed, effective November 1, 2012, on a temporary basis and subject to refund, pending the completion of a full evidentiary hearing and a final decision.

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Maryland

ESG Acquisition: On September 7, 2012, we filed an application with the Maryland PSC for approval of the purchase of the ESG operating assets and the transfer of the ESG franchises to Chesapeake (see Note 4, Acquisitions, for additional information on the ESG asset purchase). In this application, we also requested the Maryland PSC to approve the overall regulatory framework we proposed for our operation in Worcester County. The proposed regulatory framework includes: (i) a request for approval of a new gas service tariff and rates applicable to natural gas and propane distribution customers in Worcester County, including the customers currently being served by ESG; (ii) a request for approval of the capacity, supply and operating agreement with ESG for the supply and storage of propane, which will be utilized to serve the ESG system customers; and (iii) a request for approval of the accounting treatment for certain of the purchased assets. Evidentiary hearings are scheduled for the week of March 11, 2013. We anticipate that the Maryland PSC will render a final decision on our application in 2013.

Other Matter: We also had developments in the following regulatory matter in Maryland:

On December 11, 2012, the Maryland PSC held an evidentiary hearing to determine the reasonableness of the four quarterly gas cost recovery filings submitted by the Maryland division during the 12 months ended September 30, 2012. No issues were raised at the hearing. The Hearing Examiner in this proceeding issued a proposed order approving the division's four quarterly filings. This proposed order was finalized by the Maryland PSC on December 28, 2012.

Florida

Come-Back Filing: On January 30, 2012, the Florida PSC issued an order, approving, among other things, the inclusion in our rate base in Florida of an acquisition adjustment of \$34.2 million and merger-related costs of \$2.2 million, to be amortized over a 30-year period and a five-year period, respectively, using the straight-line method beginning in November 2009. The acquisition adjustment permits the recovery, through rates, and inclusion in rate base, of the premium (amount in excess of net book value) paid for the acquisition of FPU. The Florida PSC also determined that FPU and Chesapeake's Florida division did not have any excess earnings in 2010 to be refunded to customers. The Florida PSC issued a consummating order on these matters on January 30, 2012.

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The Florida PSC order allows us to classify the acquisition adjustment and merger-related costs as regulatory assets and include them in our investment, or rate base, when determining our Florida natural gas rates. In addition, our rate of return calculation will be based upon this higher level of investment, which enables us to earn a return on this investment. Pursuant to this order, we reclassified to a regulatory asset at December 31, 2011, \$31.7 million of the \$34.2 million in merger-related goodwill, which represents the portion of the goodwill allowed to be recovered in future rates after the effective date of the Florida PSC order. We also recorded as a regulatory asset \$18.1 million related to the gross-up of the acquisition adjustment for income tax. Of the \$2.2 million of merger-related costs, \$1.3 million, which represents the portion of the merger-related costs allowed to be recovered in future rates after the effective date of the Florida PSC order, had previously been deferred as a regulatory asset. We also recorded as a regulatory asset \$349,000 related to the gross-up of the merger-related costs for income tax. Based upon the effective date and outcome of the order, we began reflecting the amortization of the acquisition adjustment and merger-related costs as an expense in January 2012, and included \$2.4 million of the amortization expense in depreciation and amortization in the accompanying consolidated statement of income for the year ended December 31, 2012. We will record \$2.4 million (\$1.4 million, net of tax) in amortization expense related to these assets in 2013, \$2.3 million (\$1.4 million, net of tax) in 2014 and \$1.8 million (\$1.1 million, net of tax) annually thereafter until 2039. These amortization expenses will be non-cash charges, and the net effect of the recovery will be positive cash flow. Over the long term, inclusion of the acquisition adjustment and merger-related costs in our rate base and the recovery of these regulatory assets through amortization expense will increase our earnings and cash flows above what we would have been able to achieve absent this regulatory authorization.

In FPU's future rate proceedings, if it is determined that the level of cost savings supporting recovery of the acquisition adjustment no longer exists, the remaining acquisition adjustment may be partially or entirely disallowed by the Florida PSC. In such event, we would have to expense the corresponding unamortized amount of the disallowed acquisition adjustment.

Peninsula Pipeline: At its April 10, 2012 agenda conference, the Florida PSC approved a joint territorial agreement between FPU and Peoples Gas and other related agreements among FPU, Peninsula Pipeline and Peoples Gas. These agreements were entered into in January 2012 to enable Peninsula Pipeline and FPU to expand natural gas service into Nassau and Okeechobee Counties, Florida.

The joint territorial agreement provides for the joint construction, ownership and operation of a pipeline extending approximately 16 miles from the Duval/Nassau County line to Amelia Island in Nassau County, Florida. The 16-mile pipeline was completed and placed into service in December 2012. Under the terms of the agreement, Peninsula Pipeline owns approximately 45 percent of this 16-mile pipeline, and its portion of the estimated project cost is expected to be approximately \$5.8 million. Peoples Gas will operate the pipeline, and Peninsula Pipeline will be responsible for its portion of the operation and maintenance expenses of the pipeline based on its ownership percentage. Under a separate agreement, Peninsula Pipeline contracted with Peoples Gas for transportation service from the Peoples Gas interconnection point with an unaffiliated upstream interstate pipeline to the new jointly-owned pipeline, for an annual charge of approximately \$800,000. Peninsula Pipeline will then utilize its portion of the capacity of the pipeline jointly owned with Peoples Gas to provide transmission service to FPU for its natural gas distribution service in Nassau County. The cost of the transportation service paid to Peninsula Pipeline by FPU, which is based on the annual charge of \$2.1 million approved by the Florida PSC, is included in FPU's fuel costs. In April 2012, pending the completion of the new 16-mile pipeline, Peninsula Pipeline commenced its service to FPU, using compressed natural gas.

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

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

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

The City of Marianna filed an appeal with the Florida Supreme Court on March 7, 2012 and with the Florida PSC on March 19, 2012, seeking an appellate review of both of the decisions by the Florida PSC with respect to the protests by the City of Marianna and at this time, this appeal is pending before the Florida Supreme Court. These Florida PSC Dockets are currently in litigation status awaiting a decision by the Florida Supreme Court on the administrative appeal.

As disclosed in Note 19, Other Commitments and Contingencies, on March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the Franchise Agreement by FPU and seeking a declaratory judgment that the City of Marianna has the right to exercise its option to purchase FPU's property in the City of Marianna in accordance with the terms of the Franchise Agreement. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. See Note 19, Other Commitments and Contingencies for additional details. All related litigation expenses have been recorded as operating expenses.

On August 27, 2012, FPU filed a petition with the Florida PSC for approval to: (i) defer, as a regulatory asset, the litigation expenses associated with the litigation initiated by the City of Marianna and (ii) amortize previously expensed and future litigation expenses over five years beginning January 2013. On December 3, 2012, the Florida PSC issued an order approving FPU's request for deferral and amortization of the litigation expenses for regulatory accounting and reporting purposes. This order does not change the current rates charged by FPU to its electric customers unless FPU seeks and receives an approval from the Florida PSC in a future proceeding to recover the litigation expense in rates. Given the uncertainties of the future recovery of the litigation expenses in rates, we have not deferred the litigation expense as a regulatory asset at December 31, 2012 in the accompanying consolidated balance sheet. If we determine in the future that recovery of the litigation expenses in future rates is probable, we will establish a regulatory asset in accordance with GAAP. The total litigation expenses associated with the City of Marianna litigation was \$1.4 million at December 31, 2012.

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We have the following additional regulatory matters involving the City of Marianna:

On April 7, 2011, FPU filed a petition for approval of a mid-course reduction to its northwest division fuel rates based on two factors: (1) the amendment to the Generation Services Agreement with Gulf Power approved by the Florida PSC on June 21, 2011, and (2) a weather-related increase in sales resulting in an accelerated collection of the prior year's under-recovered costs. Pursuant to its order dated July 5, 2011, the Florida PSC approved the reduction of the fuel rates of FPU's northwest division, including the fuel rates charged to customers in the City of Marianna.

On February 24, 2012, FPU filed a revised petition for approval of a mid-course reduction to its northwest division fuel rates based on a reduction in its supplier's fuel rates, which would significantly lower purchased power costs for FPU's Northwest Division in 2012. FPU filed for this mid-course reduction in order to ensure that its customers receive these savings in the most timely manner. The Florida PSC issued an order on March 27, 2012, approving the mid-course reduction in fuel rates effective April 1, 2012. This further reduced the fuel rates of FPU's northwest division, including the fuel rates charged to customers in the City of Marianna.

On June 1, 2012, the City of Marianna filed a petition with the Florida PSC for resolution of a territorial dispute for natural gas service in Jackson County as well as the surrounding areas included in FPU's planned expansion. On June 22, 2012, FPU filed a response to the petition defending its planned expansion. On December 13, 2012, the parties filed a joint notice with the Florida PSC to withdraw the territorial dispute, and FPU no longer seeks to offer retail natural gas services in the area that was previously in dispute in this proceeding.

Gas Reliability Infrastructure Program (GRIP): On February 3, 2012, FPU's natural gas distribution operation and Chesapeake's Florida division filed a petition with the Florida PSC for approval of a GRIP surcharge to customers, which is designed to recover capital and other program-related-costs, inclusive of an appropriate return on investment, associated with accelerating the replacement of qualifying distribution mains and services (defined as any material other than coated steel or plastic (Polyethylene)) in their respective systems. We expect to incur approximately \$75.0 million over a 10-year period to replace qualifying mains and services. At the August 14, 2012 agenda conference, the Florida PSC approved a GRIP for FPU and Chesapeake's Florida division to provide an annual surcharge mechanism with quarterly reporting requirements, effective January 1, 2013. The first year surcharge will include investments made in the period from August 14, 2012 through December 31, 2013.

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

On June 21, 2011, FPU, in accordance with the Florida PSC rules, filed its 2011 depreciation study and request for new depreciation rates for its electric distribution operation, effective January 1, 2012. The Florida PSC approved the depreciation study at its January 24, 2012 agenda conference. The new approved depreciation rates are expected to reduce annual depreciation expense by approximately \$227,000.

On March 21, 2012, FPU filed a petition with the Florida PSC for approval of a negotiated contract for the purchase of renewable energy power between FPU and an unaffiliated company, which is constructing and installing a new renewable generating facility within FPU's service territory. If constructed and installed, this facility will be capable of interconnecting and selling power to FPU's northeast electric division. Overall, this contract will provide a benefit to FPU's northeast electric customers, while also promoting the State of Florida's goal of encouraging energy independence and the growth of renewable energy projects. Savings will be passed on to customers through lower fuel costs. At the agenda conference on July 17, 2012, the Florida PSC approved the contract.

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On July 12, 2012, FPU filed a petition with the Florida PSC for approval of recognition of a regulatory liability for a one-time tax contingency gain related to FPU's income tax liability, which originated prior to the acquisition by Chesapeake from excess tax depreciation on vehicles. FPU recently determined that this tax liability was no longer needed because the applicable statute of limitation of the IRS and the tax remittance period related to this tax liability have expired. FPU believes that the treatment most consistent with prior regulatory treatment of one-time gains would be to record the amount as a regulatory liability and amortize that amount over a specified period. FPU proposed to establish approximately \$1.9 million of regulatory liability (\$1.2 million of the tax contingency gain and \$748,000 as the tax gross-up) and amortize it over the period from January 2012 to October 2014. At the October 16, 2012 agenda conference, the Florida PSC approved FPU's petition. A final order was issued on November 16, 2012 and FPU began recording the amortization of this regulatory liability, effective January 1, 2012, with the cumulative effect of the amortization recorded at that time.

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

On September 28, 2012, FPU provided a letter to the Florida PSC stating its intent to request approval of a positive acquisition adjustment associated with FPU's purchase of IGC's operating assets in 2010. FPU provided this letter to the Florida PSC. In this letter, FPU also acknowledged the jurisdiction of the Florida PSC to calculate and dispose of prospective overearnings, if any, occurring after October 1, 2012 that may be found at the conclusion of the acquisition adjustment proceeding. On December 11, 2012, FPU filed a petition to request approval of a positive acquisition adjustment associated with FPU's purchase of IGC assets. The Florida PSC is expected to review this petition at the April 2013 agenda conference.

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

Eastern Shore

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

Rate Case Filing: On December 30, 2010, Eastern Shore filed with the FERC a base rate proceeding in accordance with the terms of the settlement in its prior base rate proceeding. Conferences involving Eastern Shore, the FERC Staff and other interested parties resulted in a settlement based on an annual cost of service of approximately \$29.1 million and a pre-tax return of 13.9 percent. Also included in the settlement is a negotiated rate adjustment, effective November 1, 2011, associated with the phase-in of an additional 15,000 Dts/d of new transmission service on Eastern Shore's eight-mile extension to interconnect with TETLP's pipeline system. This rate adjustment reduces the rate per Dt of the service on this eight-mile extension by reflecting the increased service of 15,000 Dts/d with no additional revenue. This rate adjustment effectively offsets the increased revenue that would have been generated from the 15,000 Dts/d increase in firm service, although Eastern Shore may still collect a commodity charge on the increased volume from the phase-in of service. The settlement also provides a five-year moratorium on the parties' rights to challenge Eastern Shore's rates and on Eastern Shore's right to file a base rate increase but allows Eastern Shore to file for rate adjustments during those five years in the event certain costs related to government-mandated obligations are incurred and Eastern Shore's pre-tax earnings do not equal or exceed 13.9 percent. The FERC approved the settlement on January 24, 2012.

From July 2011 through October 2011, Eastern Shore adjusted its billing to reflect the rates requested in the base rate proceeding, subject to refund to customers upon the FERC's approval of the new rates. Commencing in November 2011, Eastern Shore adjusted its billing to reflect the settlement rates, subject to refund to customers upon FERC's approval of the settlement. At December 31, 2011, Eastern Shore had recorded approximately \$1.3 million as a regulatory liability related to the refund due to customers as a result of the settlement; the refund was paid in January and February 2012.

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Mainline Expansion Project: On May 14, 2012, Eastern Shore submitted to the FERC an Application for a Certificate of Public Convenience and Necessity for approval to construct, own and operate the facilities necessary to deliver additional firm service of 15,040 Dts/d to an existing electric power generation customer and to Chesapeake's Delaware and Maryland divisions. The estimated capital cost of the project is approximately \$16.3 million. The filing was publicly noticed on May 25, 2012. Two of Eastern Shore's existing customers and Chesapeake's Delaware and Maryland divisions filed motions to intervene in support of the project. One existing customer filed a motion to intervene and protest. On June 28, 2012, Eastern Shore submitted a response to the protest, and on August 31, 2012, the protesting customer filed a response to Eastern Shore's response. On October 3, 2012, the US Department of the Interior submitted comments on the FERC's environmental assessment regarding Eastern Shore's re-vegetation plan. On October 9, 2012, a non-profit organization also submitted comments with regard to the FERC's environmental assessment, requesting the FERC to extend the comment period by 60 days in order to allow adequate time for public review and comment, as well as other claims that the FERC's environmental assessment was deficient. In February 2013, the FERC approved Eastern Shore's application.

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

Other Matters: Eastern Shore also had developments in the following FERC matters:

On March 7, 2011, Eastern Shore filed certain tariff sheets to amend the creditworthiness provisions contained in its FERC Gas Tariff. On April 6, 2011, the FERC issued an order accepting and suspending Eastern Shore's filed tariff revisions, effective April 1, 2011, subject to Eastern Shore submitting certain clarifications with regard to several proposed revisions. Eastern Shore responded with a revised filing on January 13, 2012, which the FERC approved on February 24, 2012.

On March 1, 2012, Eastern Shore filed revised tariff sheets to amend certain provisions contained in the Construction of Facilities and Right of First Refusal sections of its FERC Gas Tariff. On April 6, 2012, the FERC issued an order accepting Eastern Shore's revised tariff sheet, effective April 1, 2012, subject to Eastern Shore submitting two additional revisions proposed by an intervening party during the review period. Eastern Shore responded with a revised filing on April 16, 2012, which the FERC accepted.

On June 27, 2012, Eastern Shore submitted a combined filing for its Fuel Retention Percentage (FRP) and Cash-Out Surcharge to the FERC, which encompassed a 24-month period from April 2010 to March 2012. In the filing, Eastern Shore proposed to maintain its existing zero FRP rate and its existing zero rate for the Cash-Out Surcharge. Eastern Shore also proposed to refund approximately \$320,000, inclusive of interest, to its eligible customers as a result of combining its over-recovered Gas Required for Operations and its over-recovered Cash-Out Cost. On October 19, 2012, the FERC issued an order accepting Eastern Shore's proposal. The proposed refund has been accrued and included in regulatory liabilities (current) in the accompanying consolidated balance sheet at December 31, 2012.

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18. ENVIRONMENTAL COMMITMENTS AND CONTINGENCIES

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

We have participated in the investigation, assessment or remediation, and have exposures at six former 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 MDE regarding a seventh former MGP site located in Cambridge, Maryland.

As of December 31, 2012, we had approximately \$10.5 million in environmental liabilities related to all of FPU's MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites, representing our estimate of the future costs associated with those sites. FPU has approval to recover up to \$14.0 million of its environmental costs related to all of its MGP sites from insurance and from customers through rates, approximately \$8.7 million of which has been recovered as of December 31, 2012. We had approximately \$5.3 million in regulatory assets for future recovery of environmental costs from FPU's customers.

In addition to the FPU MGP sites, we had \$170,000 in environmental liabilities at December 31, 2012, related to Chesapeake's MGP sites in Maryland and Florida, representing our estimate of future costs associated with these sites. As of December 31, 2012, we had approximately \$612,000 in regulatory and other assets for future recovery through Chesapeake's rates. Environmental liabilities for all of our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants.

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

The following discussion provides details on MGP sites:

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, where FPU previously operated an MGP. FPU is currently implementing a remedial plan approved by the Florida Department of Environmental Protection (FDEP) for the east parcel of the West Palm Beach site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. It is anticipated that similar remedial actions ultimately will be implemented for other portions of the site. Estimated costs of remediation for the West Palm Beach site range from approximately \$4.5 million to \$15.4 million, including costs associated with the relocation of FPU's operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties. We continue to expect that all costs related to these activities will be recoverable from customers through rates.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP. In January 2007, FPU and other responsible parties at the Sanford site (collectively with FPU the Sanford Group) signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. FPU's share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of \$13.0 million, or \$650,000. As of December 31, 2012, FPU has paid \$650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

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

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As of December 31, 2012, FPU's remaining remediation expenses, including attorneys' fees and costs, are estimated to be \$24,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU's asserted defense to liability for costs exceeding \$13.0 million as provided in the Third Participation Agreement to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the \$650,000 that FPU has paid under the Third Participation Agreement. No such claims have been made as of December 31, 2012.

Key West, Florida

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

Pensacola, Florida

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

Salisbury, Maryland

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

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Winter Haven, Florida

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

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

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

Other

We are in discussions with the MDE regarding a former MGP site located in Cambridge, Maryland. The outcome of this matter cannot be determined at this time; therefore, we have not recorded an environmental liability for this location.

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

Table of Contents**Notes to the Consolidated Financial Statements****19. OTHER COMMITMENTS AND CONTINGENCIES*****Litigation***

On March 2, 2011, the City of Marianna filed a complaint against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida. In the complaint, the City of Marianna alleged three breaches of the Franchise Agreement by FPU: (i) FPU failed to develop and implement TOU and interruptible rates that were mutually agreed to by the City of Marianna and FPU; (ii) mutually agreed upon TOU and interruptible rates by FPU were not effective or in effect by February 17, 2011; and (iii) FPU did not have such rates available to all of FPU's customers located within and without the corporate limits of the City of Marianna. The City of Marianna is seeking a declaratory judgment allowing it to exercise its option under the Franchise Agreement to purchase FPU's property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Marianna Commission, which would also need to approve the presentation of a referendum to voters in the City of Marianna related to the purchase and the operation by the City of Marianna of an electric distribution facility. If the purchase is approved by the Marianna Commission and the referendum is approved by the voters, the closing of the purchase must occur within 12 months after the referendum is approved. On March 28, 2011, FPU filed its answer to the declaratory action by the City of Marianna, in which it denied the material allegations by the City of Marianna and asserted several affirmative defenses. On August 3, 2011, the City of Marianna notified FPU that it was formally exercising its option to purchase FPU's property. On August 31, 2011, FPU advised the City of Marianna that it has no right to exercise the purchase option under the Franchise Agreement and that FPU would continue to oppose the effort by the City of Marianna to purchase FPU's property. In December 2011, the City of Marianna filed a motion for summary judgment. FPU opposed the motion. On April 3, 2012, the court conducted a hearing on the City of Marianna's motion for summary judgment. The court subsequently denied in part and granted in part the City of Marianna's motion after concluding that issues of fact remained for trial with respect to each of the three alleged breaches of the Franchise Agreement. Mediation was conducted on May 11, 2012, and again on July 6, 2012, but no resolution was reached. The case was originally scheduled for trial in October 2012, however, due to a scheduling conflict, the trial was rescheduled to February 2013. Prior to the scheduled trial date, FPU and the City of Marianna reached an agreement in principle to resolve their dispute, which resulted in the City of Marianna dismissing its legal action with prejudice on February 11, 2013. The agreement in principle requires the City of Marianna and FPU to negotiate and prepare a formal settlement agreement that is subject to approval by FPU's Board of Directors and the Marianna Commission. The settlement agreement would contemplate, in pertinent part, the sale of FPU's facilities within the City of Marianna's corporate limits to the City of Marianna and, in connection therewith, require the City of Marianna to enter into an operating agreement with FPU pursuant to which FPU will operate and maintain the facilities sold to the City of Marianna. The agreement in principle requires FPU and the City of Marianna to submit the formal settlement agreement to the FPU Board of Directors and Marianna Commission for approval by March 15, 2013. If the settlement agreement is approved by both the FPU Board of Directors and the Marianna Commission, the agreement in principle requires the City of Marianna to proceed with a referendum on the acquisition of FPU's facilities in April 2013 or as soon as practicable thereafter and prohibits FPU from opposing or interfering with that referendum. If the settlement agreement is not approved by either the FPU Board of Directors or the Marianna Commission, the agreement in principle permits the City of Marianna to proceed immediately with a referendum on the acquisition of FPU's facilities and permits FPU to contest that referendum. The agreement in principle further provides that (i) if the contested referendum fails, FPU's franchise with the City of Marianna shall be extended 10 years from the current expiration date in 2020; and (ii) if the contested referendum passes, the terms of the City of Marianna's purchase of FPU's facilities within the City of Marianna will be set pursuant to the procedures in the current franchise agreement. FPU and the City of Marianna are presently negotiating the terms of the formal settlement agreement and related operating agreement. Total litigation expense associated with the City of Marianna litigation is approximately \$1.4 million as of December 31, 2012. These costs have been expensed as incurred, however, the Florida PSC has permitted FPU to seek recovery in a future rate proceeding.

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

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Notes to the Consolidated Financial Statements

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, 2013.

Chesapeake's Florida natural gas distribution division has firm transportation service contracts with FGT and Gulfstream. Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay for the service.

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

As discussed in Note 17 Rates and Other Regulatory Activities, on January 25, 2011, FPU entered into an amendment to its Generation Services Agreement with Gulf Power, which reduces the capacity demand quantity and provides the savings necessary to support the TOU and interruptible rates for the customers in the City of Marianna, both of which were approved by the Florida PSC. The amendment also extends the current agreement by two years, with a new expiration date of December 31, 2019.

FPU's electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU's agreement with JEA (formerly known as Jacksonville Electric Authority) requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times, and (b) fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU's electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior nine quarters: (a) funds from operations interest coverage ratio (minimum of 2 times), and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken or proposed to be taken to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. As of December 31, 2012, FPU was in compliance with all of the requirements of its fuel supply contracts.

The total purchase obligations for natural gas, electric and propane supplies are \$69.5 million for 2013, \$99.3 million for 2014-2015, \$82.0 million for 2016-2017 and \$180.2 million thereafter.

Corporate Guarantees

The Board of Directors has authorized the Company to issue corporate guarantees securing obligations of our subsidiaries and to obtain letters of credit securing our obligations, including the obligations of our subsidiaries. The maximum authorized liability under such guarantees and letters of credit is \$45.0 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, the largest portion of which are for our propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary's default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at December 31, 2012 was \$29.7 million, with the guarantees expiring on various dates through December 2013.

Chesapeake guarantees the payment of FPU's first mortgage bonds. The maximum exposure under the guarantee is the outstanding principal and accrued interest balances. The outstanding principal balances of FPU's first mortgage bonds approximate their carrying values (see Note 12, Long-Term Debt, to the Consolidated Financial Statements for further details).

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Notes to the Consolidated Financial Statements

In addition to the corporate guarantees, we have issued a letter of credit for \$1.0 million, which expires on September 12, 2013, related to the electric transmission services for FPU's northwest electric division. We have also issued a letter of credit to our current primary insurance company for \$656,000, which expires on December 2, 2013, as security to satisfy the deductibles under our various outstanding insurance policies. As a result of a change in our primary insurance company in 2010, we renewed and decreased the letter of credit for \$304,000 to our former primary insurance company, which will expire on June 1, 2013. There have been no draws on these letters of credit as of December 31, 2012. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

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

Agreements for Access to New Natural Gas Supplies

On April 8, 2010, our Delaware and Maryland divisions entered into a precedent agreement to secure firm transportation service from TETLP in conjunction with its new expansion project, which is expected to expand TETLP's mainline system by up to 190,000 Dts/d. The precedent agreement provided that, upon satisfaction of certain conditions, the parties would enter into two firm transportation service contracts, one for our Delaware division and one for our Maryland division. On February 23, 2012, in accordance with the terms outlined in the precedent agreement, our Delaware and Maryland divisions entered into two separate firm transportation service agreements with TETLP for 30,000 Dts/d and 10,000 Dts/d, respectively, which commenced in November 2012. The maximum daily quantity under these agreements increases to 34,100 Dts/d and 15,900 Dts/d, respectively in November 2013. By entering into these agreements, our Delaware and Maryland divisions satisfied the requirements of the precedent agreement and no longer have any financial exposure under the precedent agreement.

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing sales tax audits in Florida. As of December 31, 2012 and December 31, 2011, we maintained accruals of \$82,000 and \$307,000, respectively, related to additional sales taxes and gross receipts taxes that we may owe to various states.

Table of Contents**Notes to the Consolidated Financial Statements****20. QUARTERLY FINANCIAL DATA (UNAUDITED)**

In our opinion, the quarterly financial information shown below includes all adjustments necessary for a fair presentation of the operations for such periods. Due to the seasonal nature of our business, there are substantial variations in operations reported on a quarterly basis.

For the Quarters Ended	March 31	June 30	September 30	December 31
<i>(in thousands except per share amounts)</i>				
2012 ⁽¹⁾				
Operating Revenue	\$ 120,914	\$ 83,897	\$ 78,175	\$ 109,516
Operating Income	\$ 20,073	\$ 10,455	\$ 7,564	\$ 18,543
Net Income	\$ 10,727	\$ 5,060	\$ 3,219	\$ 9,857
Earnings per share:				
Basic	\$ 1.12	\$ 0.53	\$ 0.34	\$ 1.03
Diluted	\$ 1.11	\$ 0.52	\$ 0.33	\$ 1.02
2011 ⁽¹⁾				
Operating Revenue	\$ 146,597	\$ 86,831	\$ 80,610	\$ 103,988
Operating Income	\$ 24,839	\$ 7,776	\$ 5,594	\$ 15,495
Net Income	\$ 13,747	\$ 3,520	\$ 2,397	\$ 7,957
Earnings per share:				
Basic	\$ 1.44	\$ 0.37	\$ 0.25	\$ 0.83
Diluted	\$ 1.43	\$ 0.37	\$ 0.25	\$ 0.83

⁽¹⁾ The sum of the four quarters does not equal the total year due to rounding.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. 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 the Company's disclosure controls and procedures (as such term is defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended) as of December 31, 2012. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2012.

Changes in Internal Controls

There has been no change in internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2012, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

CEO and CFO Certifications

The Company's Chief Executive Officer and Chief Financial Officer have filed with the SEC the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2012. In addition, on May 31, 2012, the Company's Chief Executive Officer certified to the NYSE that he was not aware of any violation by the Company of the NYSE corporate governance listing standards.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Exchange Act. A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records which in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, Chesapeake's management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria established in a report entitled Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Chesapeake's management has evaluated and concluded that Chesapeake's internal control over financial reporting was effective as of December 31, 2012.

Our independent auditors, ParenteBeard LLC, have audited and issued their report on effectiveness of our internal control over financial reporting. That report appears on the following page.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of

Chesapeake Utilities Corporation

We have audited Chesapeake Utilities Corporation's (the "Company") internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Chesapeake Utilities Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Chesapeake Utilities Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Chesapeake Utilities Corporation as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows of Chesapeake Utilities Corporation, and our report dated March 8, 2013 expressed an unqualified opinion.

/s/ ParenteBeard LLC

ParenteBeard LLC

Philadelphia, Pennsylvania

March 8, 2013

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ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE.

The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned Election of Directors (Proposal 1), Information Concerning Nominees and Continuing Directors, Corporate Governance, Committees of the Board Audit Committee and Section 16(a) Beneficial Ownership Reporting Compliance, to be filed no later than March 31, 2013, in connection with the Company's Annual Meeting to be held on or about May 2, 2013.

The information required by this Item with respect to executive officers is, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, set forth in this report following Item 4, as Item 4A, under the caption Executive Officers of the Registrant.

The Company has adopted a Code of Ethics for Financial Officers, which applies to its principal executive officer, president, principal financial officer, principal accounting officer or controller, or persons performing similar functions. The information set forth under Item 1 hereof concerning the Code of Ethics for Financial Officers is filed herewith.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by this Item is incorporated herein by reference to the portions of the Proxy Statement, captioned Director Compensation, Executive Compensation and Compensation Discussion and Analysis in the Proxy Statement to be filed no later than March 31, 2013, in connection with the Company's Annual Meeting to be held on or about May 2, 2013.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned Security Ownership of Certain Beneficial Owners and Management to be filed no later than March 31, 2013, in connection with the Company's Annual Meeting to be held on or about May 2, 2013.

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The following table sets forth information, as of December 31, 2012, with respect to compensation plans of Chesapeake and its subsidiaries, under which shares of Chesapeake common stock are authorized for issuance:

	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			353,196 ⁽¹⁾
Equity compensation plans not approved by security holders			
Total			353,196

⁽¹⁾ Includes 317,785 shares available under the 2005 Performance Incentive Plan, 12,311 shares available under the 2005 Directors Stock Compensation Plan, and 23,100 shares available under the 2005 Employee Stock Awards Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement captioned, Corporate Governance, to be filed no later than March 31, 2013 in connection with the Company's Annual Meeting to be held on or about May 2, 2013.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by this Item is incorporated herein by reference to the portion of the Proxy Statement, captioned Fees and Services of Independent Registered Public Accounting Firm, to be filed no later than March 31, 2013, in connection with the Company's Annual Meeting to be held on or about May 2, 2013.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) The following documents are filed as part of this report:

1. Financial Statements:

Report of Independent Registered Public Accounting Firm;

Consolidated Statements of Income for each of the three years ended December 31, 2012, 2011, and 2010;

Consolidated Statements of Comprehensive Income for each of the three years ended December 31, 2012, 2011, and 2010;

Consolidated Balance Sheets at December 31, 2012 and December 31, 2011;

Consolidated Statements of Cash Flows for each of the three years ended December 31, 2012, 2011, and 2010;

Consolidated Statements of Stockholders' Equity for each of the three years ended December 31, 2012, 2011, and 2010; and

Notes to the Consolidated Financial Statements.

2. Financial Statement Schedules:

Report of Independent Registered Public Accounting Firm; and

Schedule II Valuation and Qualifying Accounts.

All other schedules are omitted, because they are not required, are inapplicable, or the information is otherwise shown in the financial statements or notes thereto.

3. Exhibits

Exhibit 2.1	Agreement and Plan of Merger between Chesapeake Utilities Corporation and Florida Public Utilities Company dated April 17, 2009, is incorporated herein by reference to Exhibit 2.1 of our Current Report on Form 8-K, filed April 20, 2009, File No. 001-11590.
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- Exhibit 3.1 Amended and Restated Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of our Quarterly Report on Form 10-Q for the period ended June 30, 2010, File No. 001-11590.
- Exhibit 3.2 Amended and Restated Bylaws of Chesapeake Utilities Corporation, effective December 4, 2012, are incorporated herein by reference to Exhibit 3 of our Current Report on Form 8-K, filed December 7, 2012, File No. 001-11590.
- Exhibit 4.1 Form of Indenture between Chesapeake and Boatmen's Trust Company, Trustee, with respect to the 8 1/4% Convertible Debentures is incorporated herein by reference to Exhibit 4.2 of our Registration Statement on Form S-2, Reg. No. 33-26582, filed on January 13, 1989.
- Exhibit 4.2 Note Purchase Agreement entered into by Chesapeake on December 27, 2000, pursuant to which Chesapeake privately placed \$20 million of its 7.83% Senior Notes, due in 2015, is incorporated by reference to Exhibit 4.4 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
- Exhibit 4.3 Note Agreement entered into by Chesapeake on October 31, 2002, pursuant to which Chesapeake privately placed \$30 million of its 6.64% Senior Notes, due in 2017, is incorporated herein by reference to Exhibit 2 of our Current Report on Form 8-K, filed November 6, 2002, File No. 001-11590.

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Exhibit 4.4	Note Agreement entered into by Chesapeake on October 18, 2005, pursuant to which Chesapeake, on October 12, 2006, privately placed \$20 million of its 5.5% Senior Notes, due in 2020, with Prudential Investment Management, Inc., is incorporated herein by reference to Exhibit 4.1 of our Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-11590.
Exhibit 4.5	Note Agreement entered into by Chesapeake on October 31, 2008, pursuant to which Chesapeake, on October 31, 2008, privately placed \$30 million of its 5.93% Senior Notes, due in 2023, with General American Life Insurance Company and New England Life Insurance Company, is incorporated by reference to Exhibit 4.7 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 4.6	Form of Indenture of Mortgage and Deed of Trust between Florida Public Utilities Company and the trustee, dated September 1, 1942 for the First Mortgage Bonds, is incorporated herein by reference to Exhibit 7-A of Florida Public Utilities Company's Registration No. 2-6087.
Exhibit 4.7	Seventeenth Supplemental Indenture entered into by Chesapeake Utilities Corporation and Florida Public Utilities Company, on April 12, 2011, pursuant to which Chesapeake Utilities Corporation guarantees the payment and performance obligations of Florida Public Utilities Company under the Indenture, is incorporated herein by reference to Exhibit 4.1 of our Quarterly Report on Form 10-Q for the period ended March 31, 2011, File No. 001-11590.
Exhibit 4.8	Sixteenth Supplemental Indenture entered into by Chesapeake Utilities Corporation and Florida Public Utilities Company, on December 1, 2009, pursuant to which Chesapeake Utilities Corporation, on December 1, 2009 guaranteed the secured First Mortgage Bonds of Florida Public Utilities Company under the Merger Agreement, is incorporated herein by reference to Exhibit 4.9 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
Exhibit 4.9	Thirteenth Supplemental Indenture entered into by Florida Public Utilities Company on June 1, 1992, pursuant to which Florida Public Utilities, on May 1, 1992, privately placed \$8,000,000 of its 9.08% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 1992.
Exhibit 4.10	Twelfth Supplemental Indenture entered into by Florida Public Utilities on May 1, 1988, pursuant to which Florida Public Utilities Company, on May 1, 1988, privately placed \$10,000,000 and \$5,000,000 of its 9.57% First Mortgage Bonds and 10.03% First Mortgage Bonds, respectively, are incorporated herein by reference to Exhibit 4 to Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 1988.
Exhibit 4.11	Note Agreement entered into by Chesapeake on June 23, 2011, pursuant to which Chesapeake privately placed \$29 million of its 5.68% Senior Notes, due in 2026, with Metropolitan Life Insurance Company and New England Life Insurance Company is not being filed herewith pursuant to Item 601(b)(4)(v) of Regulation S-K under the Securities Act of 1933, as amended. We hereby agree to furnish a copy of that agreement to the SEC upon request.
Exhibit 10.1*	Chesapeake Utilities Corporation Cash Bonus Incentive Plan, dated January 1, 2005, is incorporated herein by reference to Exhibit 10.3 of our Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-11590.

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Exhibit 10.2*	Chesapeake Utilities Corporation Directors Stock Compensation Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
Exhibit 10.3*	Chesapeake Utilities Corporation Employee Stock Award Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
Exhibit 10.4*	Chesapeake Utilities Corporation Performance Incentive Plan, adopted in 2005, is incorporated herein by reference to our Proxy Statement dated March 28, 2005, in connection with our Annual Meeting held on May 5, 2005, File No. 001-11590.
Exhibit 10.5*	Chesapeake Utilities Corporation Deferred Compensation Plan, amended and restated as of January 1, 2009, is incorporated herein by reference to Exhibit 10.5 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.6*	First Amendment to the Chesapeake Utilities Corporation Deferred Compensation Plan, dated December 28, 2010, is incorporated herein by reference to Exhibit 10.6 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
Exhibit 10.7	Consulting Agreement dated January 2, 2013, by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is filed herewith.
Exhibit 10.8*	Executive Employment Agreement dated January 14, 2011, by and between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
Exhibit 10.9*	Executive Employment Agreement dated January 9, 2013, by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is filed herewith.
Exhibit 10.10*	Executive Employment Agreement dated January 9, 2013, by and between Chesapeake Utilities Corporation and Beth W. Cooper, is filed herewith.
Exhibit 10.11*	Executive Employment Agreement dated January 9, 2013, by and between Chesapeake Utilities Corporation and Elaine B. Bittner, is filed herewith.
Exhibit 10.12*	Form of Performance Share Agreement effective January 6, 2010 for the period 2010 to 2012, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.24 on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 10.13*	Form of Performance Share Agreement, effective January 14, 2011 for the period 2011 to 2013, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Joseph Cumiskey, and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed January 21, 2011, File No. 001-11590.
Exhibit 10.14*	Form of Performance Share Agreement, effective January 14, 2011 for the period 2011 to 2012, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters and Elaine B. Bittner, is incorporated herein by reference to Exhibit 10.28 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
Exhibit 10.15	Form of Performance Share Agreement, effective January 5, 2012 for the period 2012 to 2014, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson and Elaine B. Bittner, is filed herewith.

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Exhibit 10.16*	Chesapeake Utilities Corporation Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.27 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.17*	First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Plan as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.30 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-11590.
Exhibit 10.18*	Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, as amended and restated effective January 1, 2009, is incorporated herein by reference to Exhibit 10.28 of our Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-11590.
Exhibit 10.19*	First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, dated October 28, 2010, is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended September 30, 2010, File No. 001-11590.
Exhibit 10.20	Second Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Savings Plan, effective January 1, 2012, is filed herewith.
Exhibit 10.21	Amended and Restated Electric Service Contract between Florida Public Utilities Company and JEA dated November 6, 2008, is incorporated herein by reference to Exhibit 10.1 of Florida Public Utilities Company's Current Report on Form 8-K, filed on November 6, 2008, File No. 001-10908.
Exhibit 10.22	Networking Operating Agreement between Florida Public Utilities Company and Southern Company Services, Inc. dated December 27, 2007 and amended on June 3, 2008, is incorporated herein by reference to Exhibit 10.3 of Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 001-10608.
Exhibit 10.23	Network Integration Transmission Service Agreement between Florida Public Utilities Company and Southern Company Services, Inc. dated December 27, 2007 and amended on June 3, 2008, is incorporated herein by reference to Exhibit 10.4 of Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 001-10608.
Exhibit 10.24	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to February 2016 (Contract No. 107033), is incorporated herein by reference to Exhibit 10.1 of Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
Exhibit 10.25	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to March 2022 (Contract No. 107034), is incorporated herein by reference to Exhibit 10.2 of Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.
Exhibit 10.26	Form of Service Agreement for Firm Transportation Service between Florida Public Utilities Company and Florida Gas Transmission Company, LLC dated November 1, 2007 for the period November 2007 to February 2022 (Contract No. 107035), is incorporated herein by reference to Exhibit 10.3 of Florida Public Utilities Company's Quarterly Report on Form 10-Q for the period ended September 30, 2007, File No. 001-10608.

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Exhibit 10.27	Precedent Agreement between Chesapeake Utilities Corporation and Texas Eastern Transmission LP, dated April 8, 2010 is incorporated herein by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, File No. 001-11590.
Exhibit 10.28	Form of Franchise Agreement between Florida Public Utilities Company and the city of Marianna, effective February 1, 2010, is incorporated herein by reference to Exhibit 10.41 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-1068.
Exhibit 10.29	Form of Service Agreement for Generation Services entered into by Florida Public Utilities Company and Gulf Power Company, dated December 28, 2006, effective January 1, 2008 is hereby incorporated herein by reference to Exhibit 10(s) on Florida Public Utilities Company's Annual Report on Form 10-K for the year ended December 31, 2006, File No. 001-10608.
Exhibit 10.30	Amendment to Form of Service Agreement for Generation Services entered into by Florida Public Utilities Company and Gulf Power Company, effective January 25, 2011, is incorporated herein by reference to Exhibit 10.43 of our Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-10608.
Exhibit 10.31	Form of Separation Agreement and Release between Chesapeake Utilities Corporation and Joseph Cummiskey, effective February 24, 2012, is incorporated herein by reference to Exhibit 10.33 of our Annual Report on Form 10-K/A for the year ended December 31, 2011, File No. 001-10608.
Exhibit 12	Computation of Ratio of Earning to Fixed Charges is filed herewith.
Exhibit 14.1	Code of Ethics for Financial Officers is filed herewith.
Exhibit 14.2	Business Code of Ethics and Conduct is filed herewith.
Exhibit 21	Subsidiaries of the Registrant is filed herewith.
Exhibit 23.1	Consent of Independent Registered Public Accounting Firm is filed herewith.
Exhibit 31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d-14(a), dated March 8, 2013, is filed herewith.
Exhibit 31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Exchange Act Rule 13a-14(a) and 15d-14(a), dated March 8, 2013, is filed herewith.
Exhibit 32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated March 8, 2013, is filed herewith.
Exhibit 32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350, dated March 8, 2013, is filed herewith.
Exhibit 101.INS XBRL	Instance Document is filed herewith.
Exhibit 101.SCH XBRL	Taxonomy Extension Schema Document is filed herewith.
Exhibit 101.CAL XBRL	Taxonomy Extension Calculation Linkbase Document is filed herewith.
Exhibit 101.DEF XBRL	Taxonomy Extension Definition Linkbase Document is filed herewith.
Exhibit 101.LAB XBRL	Taxonomy Extension Label Linkbase Document is filed herewith.
Exhibit 101.PRE XBRL	Taxonomy Extension Presentation Linkbase Document is filed herewith.

* Management contract or compensatory plan or agreement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, Chesapeake Utilities Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

By: /s/ MICHAEL P. McMASTERS
Michael P. McMasters,
President and Chief Executive Officer
Date: March 8, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ RALPH J. ADKINS
Ralph J. Adkins,
Chairman of the Board and Director
Date: March 8, 2013

/s/ MICHAEL P. McMASTERS
Michael P. McMasters,
President, Chief Executive Officer and Director
Date: March 8, 2013

/s/ BETH W. COOPER
Beth W. Cooper, Senior Vice President
and Chief Financial Officer
(Principal Financial and Accounting Officer)
Date: March 8, 2013

/s/ EUGENE H. BAYARD, ESQ
Eugene H. Bayard, Esq., Director
Date: March 8, 2013

/s/ RICHARD BERNSTEIN
Richard Bernstein, Director
Date: March 8, 2013

/s/ THOMAS J. BRESNAN
Thomas J. Bresnan, Director
Date: March 8, 2013

/s/ THOMAS P. HILL, JR.
Thomas P. Hill, Jr., Director
Date: March 8, 2013

/s/ DENNIS S. HUDSON, III
Dennis S. Hudson, III, Director
Date: March 8, 2013

/s/ PAUL L. MADDOCK, JR.
Paul L. Maddock, Jr., Director
Date: March 8, 2013

/s/ J. PETER MARTIN
J. Peter Martin, Director
Date: March 8, 2013

/s/ JOSEPH E. MOORE, ESQ
Joseph E. Moore, Esq., Director
Date: March 8, 2013

/s/ CALVERT A. MORGAN, JR.
Calvert A. Morgan, Jr., Director
Date: March 8, 2013

/s/ DIANNA F. MORGAN
Dianna F. Morgan, Director
Date: March 8, 2013

/s/ JOHN R. SCHIMKAITIS
John R. Schimkaitis
Vice Chairman of Board and Director
Date: March 8, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of

Chesapeake Utilities Corporation

The audit referred to in our report dated March 8, 2013 relating to the consolidated financial statements of Chesapeake Utilities Corporation as of December 31, 2012 and 2011 and for each of the years in the three-year period ended December 31, 2012, which is contained in Item 8 of this Form 10-K also included the audits of the financial statement schedule listed in Item 15(a)2. This financial statement schedule is the responsibility of the Chesapeake Utilities Corporation's management. Our responsibility is to express an opinion on this financial statement schedule based on our audits.

In our opinion such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ ParenteBeard LLC

ParenteBeard LLC

Philadelphia, Pennsylvania

March 8, 2013

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Chesapeake Utilities Corporation and Subsidiaries

Schedule II

Valuation and Qualifying Accounts

For the Year Ended December 31, (In thousands)	Balance at Beginning of Year	Additions		Deductions (⁽²⁾)	Balance at End of Year
		Charged to Income	Other Accounts ⁽¹⁾		
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
2012	\$ 1,090	\$ 826	\$ 354	(\$1,444)	\$ 826
2011	\$ 1,194	\$ 1,157	\$ 293	(\$1,554)	\$ 1,090
2010	\$ 1,609	\$ 1,129	\$ 181	(\$1,725)	\$ 1,194

(1) Recoveries.

(2) Uncollectible accounts charged off.