CHESAPEAKE UTILITIES CORP
Form 10-K
March 08, 2011

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, 2010
Commission File Number: 001-11590

Chesapeake Utilities Corporation
(Exact name of registrant as specified in its charter)

State of Delaware	**51-0064146**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including zip code)
302-734-6799
(Registrant s telephone number, including area code)
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 o. No þ.
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 o. No þ.
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ. No o.
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o. No o.
Indicate by check mark 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. þ
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 o Accelerated filer þ Non-accelerated filer o Smaller Reporting Company o

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

The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation as of June 30, 2010, 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 $297.6 million.

As of February 28, 2011, 9,529,333 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2011 Annual Meeting of Stockholders are incorporated by reference in Part II and Part III.

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GLOSSARY OF KEY TERMS

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

Subsidiaries of Chesapeake Utilities Corporation

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

Regulatory Agencies

Delaware PSC	Delaware Public Service Commission
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FDEP	Florida Department of Environmental Protection
Florida PSC	Florida Public Service Commission
IASB	International Accounting Standards Board
IRS	Internal Revenue Service
Maryland PSC	Maryland Public Service Commission
MDE	Maryland Department of the Environment
PSC	Public Service Commission
SEC	Securities and Exchange Commission

Accounting Standards Related

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

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Other

AS/SVE	Air Sparging and Soil/Vapor Extraction
BS/SVE	Bio-Sparging and Soil/Vapor Extraction
CDD	Cooling Degree-Days
Columbia	Columbia Gas Transmission, LLC
DSCP	Directors Stock Compensation Plan
Dts	Dekatherms
Dts/d	Dekatherms per Day
FCG	Florida City Gas
FGT	Florida Gas Transmission Company
FRP	Fuel Retention Percentage
GSR	Gas Sales Service Rates
Gulf	Columbia Gulf Transmission Company
Gulf Power	Gulf Power Company
Gulfstream	Gulfstream Natural Gas System, LLC
HDD	Heating Degree-Days
IGC	Indiantown Gas Company
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MWH	Megawatt Hour
NYSE	New York Stock Exchange
PIP	Performance Incentive Plan
RAP	Remedial Action Plan
S&P 500 Index	Standard & Poor s 500 Index
Sanford Group	FPU and Other Responsible Parties involved with the Sanford Environmental Site
TETLP	Texas Eastern Transmission, LP
Transco	Transcontinental Gas Pipe Line Company, LLC

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Part I

References in this document to Chesapeake, the Company, we, us and our mean Chesapeake Utilities Corpo
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 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. You can typically identify forward-looking statements by the use of forward-looking words, such as project, believe, expect, anticipate, intend, plan, estimate, continue, potential, forecast or other similar words, or future or cond
such as may, will, should, would or could. These statements represent our intentions, plans, expectations, assum
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;
- industrial, commercial and residential growth or contraction in our service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes and ice storms;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions, including any potential effects arising from terrorist attacks and any consequential hostilities, other hostilities or other external factors over which we have no control;
- changes in environmental and other laws and regulations to which we are subject;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- declines in the market prices of equity securities and resultant cash funding requirements for our defined benefit pension plans;
- the creditworthiness of counterparties with which we are engaged in transactions;
- growth in opportunities for our business units;
- the extent of success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets and equity markets during the periods covered by the forward-looking statements;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the ability to manage and maintain key customer relationships;
- the ability to maintain key supply sources;

- the effect of spot, forward and future market prices on our distribution, wholesale marketing and energy trading businesses;
- the effect of competition on our businesses;
- the ability to construct facilities at or below estimated costs;
- changes in technology affecting our advanced information services business; and
- operational and litigation risks that may not be covered by insurance.

Item 1. Business.

(a) Overview

We are a diversified utility company engaged in various energy and other businesses. Chesapeake is a Delaware corporation that was formed in 1947. 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. We operate regulated energy businesses through our natural gas distribution divisions in Delaware, Maryland and Florida, natural gas and electric distribution operations in Florida through FPU, and natural gas transmission operations on the Delmarva Peninsula and Florida through our subsidiaries, Eastern Shore Natural Gas Company (ESNG) and Peninsula Pipeline Company, Inc. (PIPECO), respectively. Our unregulated businesses include our natural gas marketing operation through Peninsula Energy Services Company, Inc. (PESCO); propane distribution operations through Sharp Energy, Inc. and its subsidiary Sharpgas, Inc. (collectively Sharp) and FPU s propane distribution subsidiary, Flo-Gas Corporation; and our propane wholesale marketing operation through Xeron, Inc. (Xeron). We also have an advanced information services subsidiary, BravePoint®, Inc. (BravePoint).

(b) Operating Segments

We are composed of three operating segments:

- *Regulated Energy*. The regulated energy segment includes natural gas distribution, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and services, by the Public Service Commission (PSC) having jurisdiction in each operating territory or by the Federal Energy Regulatory Commission (FERC) in the case of ESNG.
- *Unregulated Energy.* The unregulated energy segment includes natural gas marketing, propane distribution and propane wholesale marketing operations, which are unregulated as to their rates and services.
- *Other*. The other segment consists primarily of the advanced information services operation, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

The following table shows the size of each of our operating segments based on operating income for 2010 and net property, plant and equipment as of December 31, 2010:

(in thousands)	**Operating Income**		**Net Property, Plant & Equipment**	
Regulated Energy	$ 43,509	84%	$ 414,622	90%
Unregulated Energy	7,908	15%	35,658	8%
Other	513	1%	12,477	2%
Total	$ 51,930	100%	$ 462,757	100%

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

(i) Regulated Energy

Our regulated energy segment provides natural gas distribution services in Delaware, Maryland and Florida, electric distribution services in Florida and natural gas transmission services in Delaware, Maryland, Pennsylvania and Florida.

Natural Gas Distribution

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. With 99 percent of the natural gas consumed in the United States coming from North America, supplies of natural gas are abundant. 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.

Our Delaware and Maryland natural gas distribution divisions serve 52,686 residential and commercial customers and 177 industrial customers in central and southern Delaware and Maryland s Eastern Shore. For the year ended December 31, 2010, operating revenues and deliveries by customer class for our Delaware and Maryland distribution divisions were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(Mcfs)*	
Residential	$ 46,041	57%	2,881,073	35%
Commercial	27,896	34%	2,145,143	26%
Industrial	3,766	5%	3,020,907	36%
Subtotal	77,703	96%	8,047,123	97%
Interruptible	655	1%	232,653	3%
Other [(1)]	2,507	3%		
Total	$ 80,865	100%	8,279,776	100%

(1) Operating revenues from other include unbilled revenue, rental of gas properties, and other miscellaneous charges.

Our Florida natural gas distribution operations consist of Chesapeake s Florida division and FPU s natural gas operation, which was acquired in the merger with FPU in October 2009. In August 2010, FPU added a new division through the purchase of the natural gas operating assets of Indiantown Gas Company (IGC). On a combined basis, our Florida natural gas distribution operations serve 61,053 residential customers and 6,314 commercial and industrial customers in 20 counties in Florida. For the year ended December 31, 2010, operating revenues and deliveries by customer class for our Florida natural gas distribution operations were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(Mcf s)*	
Residential	$ 27,742	35%	1,716,934	8%
Commercial	39,006	48%	4,451,414	20%
Industrial	13,043	16%	15,582,234	72%
Other [(1)]	607	1%	12,723	
Total	$ 80,398	100%	21,763,305	100%

(1) Operating revenues from "other" include unbilled revenue, conservation revenue, fees for billing services provided to third parties and other miscellaneous charges.

Electric Distribution

Our Florida electric distribution operation, which was acquired in the FPU merger, distributes electricity to 30,966 customers in four counties in northeast and northwest Florida. For the year ended December 31, 2010, operating revenues and deliveries by customer class for the FPU electric distribution operation were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(MWHs)*	
Residential	$ 51,498	55%	347,040	47%
Commercial	45,332	48%	332,322	45%
Industrial	7,705	8%	66,580	9%
Subtotal	104,535	111%	745,942	101%
Other [1]	(10,452)	(11%)	(6,286)	(1%)
Total	$ 94,083	100%	739,656	100%

[1] Operating revenues from other include unbilled revenue, under (over) recoveries of fuel cost, conservation revenue, other miscellaneous charges and adjustments for pass-through taxes.

Natural Gas Transmission

ESNG operates a 396-mile interstate pipeline system that transports natural gas from various points in Pennsylvania to Chesapeake s 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. ESNG also provides swing transportation service and contract storage services. For the year ended December 31, 2010, operating revenues and deliveries by customer class for ESNG were as follows:

	Operating Revenues *(in thousands)*		Deliveries *(Mcfs)*	
Local distribution companies	$ 20,441	76%	10,848,108	62%
Industrial	4,864	18%	4,794,442	27%
Commercial	1,571	6%	1,962,890	11%
Other [1]	41	0%		
Subtotal	26,917	100%	17,605,440	100%
Less: affiliated local distribution companies	(12,903)	(48%)	(5,853,083)	(33%)
Total non-affiliated	$ 14,014	52%	11,752,357	67%

[1] Operating revenues from other sources are from rental of gas properties.

PIPECO currently provides natural gas transportation services to a customer for a period of 20 years beginning in January 2009 at a fixed monthly charge, through an eight-mile pipeline located in Suwanee County, Florida, which PIPECO owns. For the year ended December 31, 2010, PIPECO had $264,000 in operating revenues under the contract.

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- Delaware and Maryland

Our Delaware and Maryland natural gas distribution divisions have both firm and interruptible transportation service contracts with five interstate open access pipeline companies, including the ESNG pipeline. These divisions are directly interconnected with the ESNG pipeline, and have contracts with interstate pipelines upstream of ESNG, 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 ESNG pipeline. The Gulf pipeline is directly interconnected with the Columbia pipeline and indirectly interconnected with the ESNG pipeline. None of the upstream pipelines is owned or operated by an affiliate of the Company.

On April 8, 2010, our Delaware and Maryland divisions entered into a Precedent Agreement with TETLP in conjunction with TETLP s new expansion project. Upon satisfaction of certain conditions provided in the Precedent Agreement, the Delaware and Maryland divisions will execute two firm transportation service contracts, one for our Delaware division for 28,986 Mcfs per day and one for our Maryland division for 9,662 Mcfs per day, to be effective on the service commencement date of the project, which is currently projected to occur in November 2012. The new firm transportation service contracts between our Delaware and Maryland divisions and TETLP will provide us with an additional direct interconnection with ESNG s transmission system and access to new sources of natural gas supplies from other natural gas production regions, including the Appalachian production region, thereby providing increased reliability and diversity of supply. They will also provide our Delaware and Maryland divisions with additional upstream transportation capacity to meet current customer demands and to plan for sustainable growth. In December 2010, ESNG completed its mainline extension to interconnect with the TETLP pipeline. Until TETLP s expansion project is completed, our Delaware and Maryland divisions expect to utilize currently available capacity on a portion of TETLP s existing pipeline. For the 2010 and 2011 winter season, our Delaware and Maryland divisions have contracted for 14,493 Mcfs per day and 4,831 Mcfs per day, respectively, from TETLP.

The Delaware and Maryland divisions use their firm transportation supply resources to meet a significant percentage of their projected demand requirements and they purchase natural gas supplies on the spot market from various suppliers as needed to match firm supply and demand. This gas is transported by the upstream pipelines and delivered to their interconnections with ESNG. These divisions also have the capability to use propane-air peak-shaving to supplement or displace spot market purchases.

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The following table shows the firm transportation and storage capacity that the Delaware and Maryland divisions currently have under contract with ESNG and pipelines upstream of the ESNG pipeline, including the respective contract expiration dates.

Delaware

Pipeline	**Firm transportation capacity maximum peak-day daily deliverability (Mcfs)**	**Firm storage capacity maximum peak-day daily withdrawal (Mcfs)**	**Expiration**
Transco	20,699	6,190	Various dates between 2012 and 2028
Columbia	17,836	7,946	Various dates between 2011 and 2020
Gulf	850		Expires in 2014
TETLP	14,493		Expires in 2012
ESNG	64,602	4,006	Various dates between 2011 and 2027

Maryland

Pipeline	**Firm transportation capacity maximum peak-day daily deliverability (Mcfs)**	**Firm storage capacity maximum peak-day daily withdrawal (Mcfs)**	**Expiration**
Transco	5,921	2,909	Various dates between 2012 and 2013
Columbia	6,473	3,539	Various dates between 2011 and 2018
Gulf	570		Expires in 2014
TETLP	4,831		Expires in 2012
ESNG	21,380	2,228	Various dates between 2011 and 2027

The Delaware and Maryland divisions currently have contracts with several suppliers for the purchase of firm natural gas supply in the amount of their capacities on the Transco and Columbia pipelines.

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 Public Service Commission (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.

Contracts by Chesapeake s Florida natural gas distribution division with FGT include: (a) a contract, which expires on July 31, 2012, for daily firm transportation capacity of 17,175 Mcfs for the months of November through April, capacity of 14,695 Mcfs for the months of May through September, and 16,143 Mcfs for October; and (b) a contract for daily firm transportation capacity of 974 Mcfs daily, which expires in 2015. Chesapeake s contract with Gulfstream is for daily firm transportation capacity of 9,737 Mcfs and expires in 2022.

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FPU has the following firm transportation contracts with FGT:
(a) two contracts expiring in July 2020 for daily firm transportation capacity of:

	Daily Firm Transportation Capacity (*in Mcfs*)
January March	28,647
April	24,156
May September	9,681
October	10,210
November December	28,647

(b) one contract expiring in February 2015 for daily firm transportation capacity of:

	Daily Firm Transportation Capacity (*in Mcfs*)
January April	10,286
May October	4,360
November December	10,286

(c) one contract for daily firm transportation capacity of 1,774 Mcfs with various partial expiration dates between 2016 and 2023.

FPU also has a firm transportation contract with Florida City Gas (FCG), expiring in 2013, which provides daily firm transportation capacity of 292 Mcfs on its Pioneer Pipeline, and a firm transportation contract with IGC, expiring in 2016, which provides daily firm transportation capacity of 487 Mcfs on its distribution system.

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

Natural Gas Transmission

ESNG has three contracts with Transco for a total of 7,045 Mcfs of firm peak day storage entitlements and total storage capacity of 278,264 Mcfs, each of which expires in 2013. ESNG has retained these firm storage services in order to provide swing transportation service and firm storage service to those customers that have requested such services.

Electric Distribution

Our electric distribution operation through FPU purchases all of its wholesale electricity from two suppliers: Gulf Power Company (Gulf Power) and JEA (formerly known as Jacksonville Electric Authority). Both of these contracts are all requirement contracts and they expire in December 2019 and December 2017, respectively. The JEA contract provides generation, transmission and distribution service to northeast Florida. The Gulf Power contract provides generation, transmission and distribution service to northwest Florida.

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 and Florida PSCs with respect to various aspects of their business, including rates for sales and transportation to all customers in each respective 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 regulatory authority having jurisdiction.

ESNG is subject to regulation as an interstate pipeline by the FERC, which regulates the terms and conditions of service and the rates ESNG can charge for its transportation and storage services. PIPECO 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 Currrent 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 Electric	Florida PSC	5/22/2008	11.00% (1)
ESNG	FERC	9/1/2007	13.60% (2)

(1) Allowed return on equity

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

(3) Effective date of the Order approving settlement agreement, which adjusted rates originally approved on June 4, 2009.

PIPECO, which is regulated by the Florida PSC, currently provides service to one customer at a negotiated rate.

On December 30, 2010, ESNG submitted a base rate filing to the FERC. See discussion of regulatory activities in Item 7 under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Rate Filings and Other Regulatory Activities.

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

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Regulatory Proceedings

See discussion of regulatory activities in Item 7 under the heading Management s Discussion and Analysis of Financial Condition and Results of Operations Rate Filings and Other Regulatory Activities.

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 sold and delivered. Specifically, customer demand substantially increases during the winter months, when natural gas is used for heating. Accordingly, the 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 use of natural gas, while sustained colder-than-normal temperatures will tend to increase 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 below 65 degrees Fahrenheit. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating 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 regardless of weather conditions, we received approval from the Maryland Public Service Commission (Maryland PSC) on September 26, 2006 to implement 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 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. Since March of 2007, the Delaware Public Service Commission (Delaware PSC) has been investigating whether to implement a revenue decoupling mechanism for the natural gas distribution utilities. Recently, the Delaware PSC decided in response to a decoupling request by another Delaware distribution utility that it would need a further review of the implementation plan, including more customer education about decoupling and the greater awareness of energy efficiency programs, prior to approving the request. Our Delaware natural gas distribution operation is currently evaluating the feasibility of decoupling. In light of the Delaware PSC s recent actions, it is uncertain as to when our Delaware natural gas distribution operation will file a request for decoupling or whether it will be required to file such request by the Delaware PSC.

(ii) Unregulated Energy

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

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Natural Gas Marketing

Our natural gas marketing subsidiary, PESCO, provides natural gas supply and supply management services to 2,486 customers in Florida and 11 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, 2010, PESCO s operating revenues and deliveries were as follows:

State		Operating Revenues *(in thousands)*		Deliveries *(Mcfs)*	
Florida	$	47,441	86%	8,236,014	84%
Delmarva		8,006	14%	1,538,895	16%
Total	$	55,447	100%	9,774,909	100%

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 Mcfs, and expire in May 2011. 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.

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.

Sharp, our propane distribution subsidiary, serves 34,243 customers throughout Delaware, the Eastern Shore of Maryland and Virginia, and southeastern Pennsylvania. Our Florida propane distribution subsidiary provides propane distribution services to 13,857 customers in parts of Florida. For the year ended December 31, 2010, operating revenues and total gallons sold by our Delmarva and Florida propane distribution operations were as follows:

State		Operating Revenues *(in thousands)*		Total Gallons Sold *(in thousands)*	
Delmarva	$	68,558	79%	32,617	82%
Florida		18,725	21%	6,995	18%
Total	$	87,283	100%	39,612	100%

Propane Wholesale Marketing

Xeron, our propane wholesale marketing operation, markets propane to large, independent petrochemical companies, resellers and retail propane companies in the southeastern United States. The propane wholesale marketing business is affected by propane wholesale price volatility and supply levels. In 2010, Xeron had operating revenues totaling approximately $1.8 million, net of the associated cost of propane sold. For further discussion of Xeron s trading and 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.

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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. Supplies of propane from these and other sources are readily available for purchase.

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 3.0 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

Natural gas marketing, propane distribution and propane wholesale 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 (DOT) 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.

(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. Certain corporate costs that have not been allocated to different operations consist of merger-related costs that have been expensed and have not been allocated because such costs are not directly attributable to the business unit operations.

Advanced Information Services

Our advanced information services subsidiary, BravePoint, is headquartered in Norcross, Georgia, and provides domestic and 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.

(ii) Employees

As of December 31, 2010, we had a total of 734 employees, 160 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 at 100 F Street, N.E., Washington, DC 20549-5546; the public may obtain information on the operation of 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 Financial Officer Code of Ethics 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. Each of these documents also is 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 June 3, 2010 that, as of that date, he was unaware of any violation by Chesapeake of the NYSE s corporate governance listing standards.

Item 1A. Risk Factors.

The following is a discussion of the primary financial, operational, regulatory and legal, and environmental risk factors that may affect the operations and/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

The anticipated benefits of the merger with FPU may not be realized.

We entered into the merger with FPU with the expectation that the merger would result in various benefits, including, among other things, synergies, cost savings and operating efficiencies. Although we have achieved significant synergies, cost savings and operating efficiencies since the merger, there can be no assurance that these benefits will be sustained in the future, or additional benefits will be achieved in the future. Failure to sustain these benefits or achieve additional benefits in the future will adversely affect our expected future performance.

We are currently in discussions with the Office of Public Counsel of Florida and the Florida PSC staff regarding the benefits and cost savings of the merger, current and expected earnings level as well as the recovery of approximately $34.9 million in purchase premium and $2.2 million in merger-related costs. If we fail to obtain the necessary approval to earn a return on the purchase premium and merger-related costs and treat the amortization as allowable operating costs, we may be required to expense the amortization of these assets without recovery which will adversely affect our financial performance for the related periods. We may also be required to pass on to ratepayers, some, or all of the increased earnings generated from cost savings, resulting from the merger.

Instability and volatility in the financial markets could have a negative impact on our growth strategy.

Our business strategy includes the continued pursuit of growth, both organically and through acquisitions. To the extent that we do not generate sufficient cash 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. Currently, $40 million of the total $100 million of short-term lines of credit utilized to satisfy our short-term financing requirements are discretionary, uncommitted lines of credit. We utilize discretionary lines of credit to reduce the cost associated with these short-term financing requirements. 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.

Debt covenant obligations, if triggered, may affect our financial condition.

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.

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

A continued downturn in the economies of the regions in which we operate, together with increased unemployment, mortgage and other credit defaults and significant decreases in the values of homes and investment assets, have adversely affected the financial resources of many domestic households. These economic conditions have slowed the growth in our customer base and cash flows. It is unclear whether governmental responses to these conditions will be successful in lessening the severity or duration of the current recession. As a result, our customers may use less natural gas, electricity or propane and it may become more difficult for them to pay their bills. This may slow collections and lead to higher than normal levels of accounts receivable, which in turn, could increase our financing requirements and result in higher bad debt expense.

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.

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

Our natural gas marketing and propane wholesale marketing operations are subject to market risks beyond their control, including market liquidity and commodity price volatility. Although we maintain a risk management policy, 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 Xeron 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 have credit risk and credit requirements that may adversely affect our results of operations, cash flows and financial condition.

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. These subsidiaries are also 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 had an adverse impact on the return on plan assets for our pension plans, which may require significant additional funding and adversely affect our cash flows.

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. As a result of the extreme volatility and disruption in the domestic and international equity and bond markets in recent years, the asset values 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 may necessitate accelerated funding of the plans in the future to meet minimum federal government requirements. Downward pressure on the asset values of our pension plans may require us to 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

We may be unable to successfully integrate operations after the merger.

The merger between Chesapeake and FPU involves the integration of two companies that have previously operated independently. We began the process of integrating operations, both geographically and organizationally, immediately after the merger and this process is still on-going today. While significant progress has been made in integration, we continue to combine and enhance various systems, facilities and personnel deployment. Throughout the integration process, we are subject to employee workforce factors, including loss of key employees, availability of qualified personnel, collective bargaining agreements with unions and work stoppages that could affect our business and financial condition. Continued integration efforts may divert management s focus and resources from other strategic opportunities. The diversion of management s attention and any delays or difficulties encountered in connection with continued integration activities could result in the disruption of our ongoing businesses or inconsistencies in standards, controls, procedures and policies that adversely affect our ability to maintain relationships with customers, suppliers, employees and others with whom we have business dealings.

Fluctuations in weather may adversely affect our results of operations, cash flows and financial condition.

Our natural gas and propane distribution operations are sensitive to fluctuations in weather conditions, which directly influence the volume of natural gas and propane sold and delivered. 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. In addition, hurricanes or other extreme weather conditions could damage production or transportation facilities, which could result in decreased supplies of natural gas, propane and electricity, increased supply costs and higher prices for customers.

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

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

Natural gas, electricity and propane production can be affected by factors beyond our control, such as weather, closings of 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.

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

Our natural gas distribution and marketing operations, electric distribution operation and propane operations have entered into various agreements with suppliers to purchase natural gas, electricity and propane to serve their 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.

We rely on having access to interstate natural gas pipelines transmission and storage capacity and electric transmission capacity; a substantial disruption or lack of growth in these services 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 natural gas supplies, interstate pipeline transmission and storage capacity, and electric transmission capacity to serve such requirements. We must contract for reliable and adequate delivery 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, FPU s natural gas is transported primarily through one pipeline system. Any interruption to that system could adversely affect our ability to meet the demands of FPU s customers and our earnings.

Commodity price changes may 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 and other fuels can significantly increase the cost of electricity billed to our electric 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.

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. 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 risk, which may adversely affect our results of operations and financial condition.

Our propane distribution operations own bulk propane storage facilities, with an aggregate capacity of approximately 3.0 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 unit 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 unit price of the propane that we purchase can change rapidly over a short period of time. The 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 U.S. generally accepted accounting principles (GAAP) if the market price of propane falls below our weighted average cost of inventory, which could adversely affect net income.

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Operating events affecting public safety and the reliability our natural gas and electric distribution systems could adversely affect the results of operations, cash flows and financial condition.

Our business is exposed to operational events, such as major leaks, mechanical problems and accidents, that could affect the public safety and reliability of our natural gas distribution and transmission systems, significantly increase costs and cause loss of customer confidence. The occurrence of any such operational events could adversely affect the results of operations, financial condition and cash flows. If we are unable to recover from customers, through the regulatory process, all or some of these costs and our authorized rate of return on these costs, this also could adversely affect the results of operations, financial condition and cash flows.

Our electric operation is subject to various operational risks, including accidents, outages, equipment breakdowns or failures, or operations below expected levels of performance or efficiency. Problems such as the breakdown or failure of electric equipment or processes and interruptions in service which would result in performance below expected levels of output or efficiency, particularly if extended for prolonged periods of time, could have a materially adverse effect on our financial condition and results of operations.

Because we operate in a competitive environment, we may lose customers to competitors which could adversely affect our results of operations, cash flows and financial condition.

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. 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 new service territories, and successfully utilizing pricing programs that retain and grow our customer base. Failure to retain and grow our customer base in our propane gas operations would have an adverse effect on our results of operations, cash flows and financial condition.

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

Changes in technology may adversely affect our advanced information services subsidiary s results of operations, cash flows and financial condition.

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.

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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 a risk management policy 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 these markets may adversely affect our gross margin in our regulated energy or propane distribution businesses, earnings and cash flows.

Our businesses are capital intensive, and the costs of capital projects may be significant.

Our businesses are capital intensive and require significant investments in internal infrastructure projects. Our results of operations and financial condition could be adversely affected if we do not pursue or are unable to manage such capital projects effectively or if full recovery of such capital costs is not permitted in future regulatory proceedings.

The risk of terrorism and political unrest and the current hostilities in the Middle East may adversely affect the economy and the price and availability of propane, refined fuels, electricity and natural gas.

Terrorist attacks, political unrest and the current hostilities in the Middle East may adversely affect the price and availability of propane, refined fuels and natural gas, as well as our results of operations, our ability to raise capital and our future growth. The impact that the foregoing may have on our industry in general, and on us in particular, is not known at this time. An act of terror could result in disruptions of crude oil, electricity or natural gas supplies and markets, and our infrastructure facilities could be direct or indirect targets. Terrorist activity may also hinder our ability to transport/transmit propane, electricity and natural gas if our means of supply transportation, such as rail, power grid or pipeline, become damaged as a result of an attack. A lower level of economic activity following such events could result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth. Instability in the financial markets as a result of terrorism could also affect our ability to raise capital. Terrorist activity and hostilities in the Middle East could likely lead to increased volatility in prices for propane, refined fuels, electricity and natural gas. We maintain insurance policies with insurers in such amounts and with such coverage and deductibles as 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.

Operational interruptions to our natural gas transmission and natural gas and electric distribution activities, caused by accidents, malfunctions, severe weather (such as a major hurricane), a pandemic or acts of terrorism, could adversely impact earnings.

Inherent in natural gas transmission and natural gas and electric distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, fires, explosions and mechanical problems. If they are severe enough or if they lead to operational interruptions, they could cause substantial financial losses. In addition, these risks could result in the loss of human life, significant damage to property, environmental damage and impairment of our operations. The location of pipeline, storage, transmission and distribution facilities near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering places, could increase the level of damages resulting from these risks. Our natural gas and electric distribution, natural gas transmission and propane storage facilities may be targets of terrorist activities that could disrupt our ability to meet customer requirements. Terrorist attacks may also disrupt capital markets and our ability to raise capital. A terrorist attack on our facilities, or those of our suppliers or customers, could result in a significant decrease in revenues or a significant increase in repair costs. The occurrence of any of these events could adversely affect our results of operations, cash flows and financial condition.

Our regulated energy business will 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 results of operation.
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.

Regulatory and Legal Risks

Regulation of our Company, 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. ESNG is regulated by the FERC. These commissions 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, these commissions may require us to refund the excess earnings or reduce our rates charged to customers in the future.
We are required to detail known benefits, synergies, cost savings and cost increases resulting from the FPU merger and present the information in the come-back filing to the Florida PSC by April 29, 2011 (within 18 months of the FPU merger). We also intend to seek for the recovery of the purchase premium and merger-related costs from the FPU merger. We are currently in discussions with the Office of Public Counsel of Florida regarding the come-back filing and the recovery of the purchase premium and merger-related costs. The outcome of such discussions or the ultimate outcome of the come-back filing, are unknown at this time.
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.
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. As a result, we are sometimes a defendant in legal proceedings arising in the ordinary course of business. We maintain insurance policies with insurers in the amount of $51 million covering general liabilities of our Company, 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 have recorded significant amounts of goodwill and regulatory assets prior to obtaining a rate order. An adverse outcome could result in an impairment of those assets.

The merger with FPU and the purchase of the operating assets from IGC resulted in approximately $34.9 million in purchase premium which is currently recorded as goodwill. We intend to seek regulatory approval to include the purchase premium and approximately $2.2 million in merger-related costs in future rates in Florida. Other utilities in Florida, including Chesapeake and FPU in the past, have been successful in recovering similar costs by demonstrating benefits to customers attributable to the business combination. The ultimate outcome of such regulatory proceedings will depend on various factors, including but not limited to, our ability to demonstrate the benefits of the merger, the regulatory environment in Florida and the results of our Florida regulated operations. If we are not successful in obtaining regulatory approval to recover these costs in future rates, we will be required to perform impairment tests of goodwill and regulatory assets, the results of which could be an impairment of all or part of the goodwill and/or regulatory assets in the future.

We may face certain regulatory and financial risks related to climate change legislation.

A number of proposals to limit greenhouse gas emissions, measured in carbon dioxide equivalent units, are pending, or at least being considered, at regional, federal and international levels. These proposals would require us to measure and potentially limit greenhouse gas emissions from our energy operations and our customers or purchase allowances for such emissions. While we cannot predict with certainty the extent of these limitations or when they will become effective, these actions could:

- increase our costs related to operations, energy efficiency activities and compliance;
- affect the demand for natural gas, electricity and propane; and
- increase the prices we charge our energy customers.

The occurrence of any such legislation could adversely affect our results of operations, financial condition and cash flows. If our regulated energy operations are unable to recover from customers through the regulatory process all or some of these costs and our authorized rate of return on these costs, this also could adversely affect our results of operations, financial condition and cash flows.

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

A number of proposals to implement increased oversight over 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. While we cannot predict with certainty the extent of these expenses and expenditures or when they will become effective, the adoption of such legislation could adversely affect our results of operations, financial conditions and cash flows. If our regulated natural gas operations are unable to recover from customers through the regulatory process all or some of these costs and our authorized rate of return on these costs, this also could adversely affect our results of operations, financial condition and cash flows.

Environmental Risks

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 current and former operating sites, including former manufactured gas plant (MGP) sites that we have acquired from third-parties. 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.

Pending environmental matters, particularly with respect to FPU s site in West Palm Beach, Florida, may have a materially adverse effect on our Company and our results of operations.

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

The site with the most potential exposure is the former West Palm Beach MGP. In November 2010, we presented a new proposed strategy with an aggressive remedial action plan to expedite remediation of this site, and the Florida Department of Environmental Protection (the FDEP) agreed with the proposal to implement a phased approach. In February 2011, FDEP approved the interim Remedial Action Plan (RAP) for the east parcel of this site, contingent upon certain conditions, and we are currently implementing the plan. Our current estimate of total remediation costs and expenses for the West Palm Beach site based on the most recently proposed remedial action plan is between \$5.1 million and \$13.3 million. This estimate does not include any costs associated with relocation of our operations from the site, which is necessary to implement the remedial action, and any potential costs associated with re-development of the properties. Actual costs may also be higher or lower than the range of current estimate based upon the final remedy required by FDEP.

As of December 31, 2010, we had recorded \$358,000 in environmental liabilities related to Chesapeake s MGP sites in Maryland and Winter Haven, Florida, representing our estimate of the future costs associated with those sites. We had recorded approximately \$1.3 million in assets for future recovery of environmental costs to be received from our customers through our approved rates. As of December 31, 2010, we had recorded approximately \$11.6 million in environmental liabilities related to FPU s MGP sites in Florida, primarily related to the West Palm Beach site. Such amount represents our estimate as of December 31, 2010, of the future costs associated with those sites, although FPU is approved to recover its environmental costs up to \$14.0 million from insurance and customers through approved rates. Of the approximately \$11.6 million recorded as environmental liabilities related to FPU s MGP sites in Florida as of December 31, 2010, we have recovered approximately \$7.8 million of environmental costs from insurance and customers through rates, and have recorded approximately \$6.2 million in assets for future recovery of environmental costs to be received from FPU s customers through approved rates.

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The costs and expenses we incur to address environmental issues at our sites may have a material adverse effect on our results of operations and earnings to the extent that such costs and expenses exceed the amounts we have accrued as environmental reserves or that we are otherwise permitted to recover from customers through rates. At present, we believe that the amounts accrued as environmental reserves and that we are otherwise permitted to recover from customers through rates are sufficient to fund the pending environmental liabilities previously described.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

(a) General

We own offices and operate facilities in the following locations: Pocomoke, Salisbury, Cambridge and Princess Anne, Maryland; Dover, Seaford, Laurel and Georgetown, Delaware; Lecanto, Virginia; and West Palm Beach, DeBary, Inglis, Indiantown, Marianna, Lantana, Lauderhill, Fernandina Beach and Winter Haven, Florida. We rent office space in Dover, Ocean View, and South Bethany, Delaware; Fernandina and Lecanto, Florida; Chincoteague and Belle Haven, Virginia; Easton, Maryland; Honey Brook 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 over 1,127 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 operations, including Chesapeake s Florida division and FPU in its service areas, own 2,451 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

ESNG owns and operates approximately 396 miles of transmission pipeline, extending from supply interconnects at Parkesburg, Pennsylvania; Daleville, Pennsylvania; Honey Brook, Pennsylvania; and Hockessin, Delaware, to approximately 80 delivery points in southeastern Pennsylvania, Delaware and the Eastern Shore of Maryland.

PIPECO owns and operates approximately eight miles of transmission pipeline in Suwanee County, Florida.

(d) Electric Distribution

The Company s electric distribution operation owns and operates 20 miles of electric transmission line located in northeast Florida and 1,128 miles of electric distribution line located in northeast and northwest Florida.

(e) Propane Distribution and Wholesale Marketing

Our Delmarva-based propane distribution operation owns bulk propane storage facilities, with an aggregate capacity of approximately 2.4 million gallons, at 42 plant facilities in Delaware, Maryland, Pennsylvania and Virginia, located on real estate that is either owned or leased by our Company. Our Florida-based propane distribution operation owns 24 bulk propane storage facilities with a total capacity of 642,000 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.

(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 and Fernandina Beach, Florida. FPU s natural gas distribution operation owns 1,659 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 1,128 miles of electric distribution line located in northeast and northwest Florida. FPU s propane distribution operation owns 24 bulk propane storage facilities with a total capacity of 642,000 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 Q, 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 P, Environmental Commitments and Contingencies.

Item 4. Removed and Reserved

Item 4A. Executive Officers of the Registrant.

Set forth below are the names, ages, and positions of executive officers of the registrant 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	52	President and Chief Executive Officer
Beth W. Cooper	44	Senior Vice President and Chief Financial Officer
Stephen C. Thompson	50	Senior Vice President and President, ESNG
Joseph Cummiskey	39	Vice President and President, PESCO
Elaine B. Bittner	41	Vice President of Strategic Development

Michael P. McMasters is President and Chief Executive Officer of Chesapeake. Mr. McMasters assumed the role of Chief Executive Officer effective January 1, 2011 and was appointed as President on March 1, 2010. Prior to these appointments, Mr. McMasters served as Chief Operating Officer since 2008, Senior Vice President since 2004 and Chief Financial Officer of Chesapeake since 1996. He has previously held the positions of Vice President, Treasurer, Director of Accounting and Rates, and Controller. From 1992 to May 1994, Mr. McMasters was employed as Director of Operations Planning for Equitable Gas Company.

Beth W. Cooper was appointed as Senior Vice President and Chief Financial Officer in September 2008 in addition to her duties as Treasurer and Corporate Secretary. Prior to this appointment, Ms. Cooper served as Vice President and Corporate Secretary of Chesapeake Utilities Corporation since July 2005. She has served as Treasurer of Chesapeake since 2003. She previously served as Assistant Treasurer and Assistant Secretary, Director of Internal Audit, Director of Strategic Planning, Planning Consultant, Accounting Manager for Non-regulated Operations and Treasury Analyst. Prior to joining Chesapeake, she was employed as an auditor with Ernst & Young s Entrepreneurial Services Group.

Stephen C. Thompson is Senior Vice President of Chesapeake and President of ESNG. Prior to becoming Senior Vice President in 2004, he served as Vice President of Chesapeake. He has also served as Vice President, Director of Gas Supply and Marketing, Superintendent of ESNG and Regional Manager for the Florida distribution operations.

Joseph Cummiskey was appointed as Vice President of Chesapeake and President of PESCO in December 2009. Mr. Cummiskey joined Chesapeake in December 2005 as the Director of Propane Supply and Wholesale Marketing. In 2008 and 2009, he served as the Director of Strategic Planning/Corporate Development and Director of Propane Operations. Prior to joining Chesapeake, Mr. Cummiskey was employed as a Natural Gas Liquids Regional Director for Ferrell North America. In that position, he was responsible for the purchasing and distribution of Ferrell s propane supply.

Elaine B. Bittner was appointed as Vice President of Strategic Development in June 2010. Prior to this appointment, Ms. Bittner served as Vice President of ESNG since 2005. She previously served as Director of ESNG, Director of Customer Services and Regulatory Affairs for ESNG, Director of Environmental Affairs for Chesapeake, Manager of Environmental Affairs and Environmental Engineer. Prior to joining Chesapeake, 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.

Part II

Item 5. Market for the Registrant s Common Equity, Related Stockholder Matters 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 the years 2010 and 2009 were as follows:

	Quarter Ended	High	Low	Close	Dividends Declared Per Share
2010					
	March 31	**$ 32.25**	**$ 28.22**	**$ 29.80**	**$ 0.315**
	June 30	**32.20**	**28.01**	**31.40**	**0.330**
	September 30	**36.93**	**30.24**	**36.22**	**0.330**
	December 31	**42.20**	**35.00**	**41.52**	**0.330**
2009					
	March 31	$ 32.36	$ 22.02	$ 30.48	$ 0.305
	June 30	34.55	27.62	32.53	0.315
	September 30	35.00	29.24	30.99	0.315
	December 31	32.67	29.53	32.05	0.315

Holders

At December 31, 2010, there were 2,482 holders of record of Chesapeake common stock.

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Dividends

We have paid a cash dividend to common stock shareholders for 50 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 2010 and 2009, totaling $1.305 per share and $1.250 per share, respectively.

Indentures to the long-term debt of the Company 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, 2010, Chesapeake s cumulative consolidated net income base was $128.9 million, offset by Restricted Payments of $76.2 million, leaving $52.7 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 provided 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, 2010, FPU had a cumulative net income base of $65.9 million, offset by restricted payments of $37.6 million, leaving $28.3 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 2010 that were not registered under the Securities Act of 1933, as amended.

(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, 2010.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[2]
October 1, 2010 through October 31, 2010 [1]	258	$ 37.58		
November 1, 2010 through November 30, 2010				
December 1, 2010 through December 31, 2010				
Total	258	$ 37.58		

[1] Chesapeake purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Note N to the Consolidated Financial Statements. During the quarter, 258 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 compensation plans of Chesapeake and its subsidiaries, 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, 2011, in connection with the Company s Annual Meeting to be held on or about May 4, 2011 and, is incorporated herein by reference.

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(c) Chesapeake Utilities Corporation Common Stock Performance Graph

The following Stock Performance graph compares cumulative total shareholder return on a hypothetical investment in our common stock during the five fiscal years ended December 31, 2010, with the cumulative total shareholder 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 11 of the companies in the current Edward Jones Natural Gas Distribution Group, a published listing of selected gas distribution utilities results. The Compensation Committee utilizes the Edward Jones Natural Gas Distribution Group as our peer group to which our performance is compared for purposes of determining the level of long-term performance awards earned by our named executives.

The eleven companies in the Edward Jones Natural Gas Distribution Group industry index include: AGL Resources, Inc., Atmos Energy Corporation, Delta Natural Gas Company, Inc., Gas Natural, Inc., The Laclede Group, Inc., New Jersey Resources Corporation, Northwest Natural Gas Company, Piedmont Natural Gas Co., Inc., RGC Resources, Inc., South Jersey Industries, Inc, and WGL Holdings, Inc.

The comparison assumes $100 was invested on December 31, 2005 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.

	2005	2006	2007	2008	2009	2010
Chesapeake	$ 100	$ 103	$ 111	$ 114	$ 121	$ 161
Industry Index	$ 100	$ 119	$ 123	$ 132	$ 136	$ 155
S&P 500 Index	$ 100	$ 116	$ 122	$ 77	$ 97	$ 112

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Item 6. Selected Financial Data

For the Years Ended December 31,	2010	2009[2]	2008
Operating[1]			
(in thousands)			
Revenues			
Regulated Energy	**$ 269,934**	$ 139,099	$ 116,468
Unregulated Energy	**146,793**	119,973	161,290
Other	**10,819**	9,713	13,685
Total revenues	**$ 427,546**	$ 268,785	$ 291,443
Operating income			
Regulated Energy	**$ 43,509**	$ 26,900	$ 24,733
Unregulated Energy	**7,908**	8,158	3,781
Other	**513**	(1,322)	(35)
Total operating income	**$ 51,930**	$ 33,736	$ 28,479
Net income from continuing operations	**$ 26,056**	$ 15,897	$ 13,607
Assets			
(in thousands)			
Gross property, plant and equipment	**$ 584,385**	$ 543,905	$ 381,689
Net property, plant and equipment	**$ 462,757**	$ 436,587	$ 280,671
Total assets	**$ 670,993**	$ 615,811	$ 385,795
Capital expenditures [1]	**$ 46,955**	$ 26,294	$ 30,844
Capitalization			
(in thousands)			
Stockholders equity	**$ 226,239**	$ 209,781	$ 123,073
Long-term debt, net of current maturities	**89,642**	98,814	86,422
Total capitalization	**$ 315,881**	$ 308,595	$ 209,495
Current portion of long-term debt	**9,216**	35,299	6,656
Short-term debt	**63,958**	30,023	33,000
Total capitalization and short-term financing	**$ 389,055**	$ 373,917	$ 249,151

(1) These amounts exclude the results of distributed energy and water services due to their reclassification to discontinued operations. The Company closed its distributed energy operation in 2007. All assets of all 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 (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. These amounts may not be indicative of future results due to the inclusion of merger effects. See Item 8 under the heading Notes to the Consolidated Financial Statements - Note B, Acquisitions and Dispositions for additional discussions and presentation of pro forma

results.

(3) SFAS No. 123R (now codified within FASB ASC 718, 505 and 260) and SFAS No. 158 (codified within FASB ASC 715) were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

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2007	2006 (3)	2005	2004	2003	2002	2001
$ 128,850	$ 124,631	$ 124,563	$ 98,139	$ 92,079	$ 82,098	$ 87,444
115,190	94,320	90,995	67,607	59,197	40,728	56,970
14,246	12,249	13,927	12,209	12,292	12,430	13,992
$ 258,286	$ 231,200	$ 229,485	$ 177,955	$ 163,568	$ 135,256	$ 158,406
$ 21,809	$ 18,593	$ 16,248	$ 16,258	$ 16,219	$ 14,867	$ 14,060
5,174	3,675	4,197	3,197	4,310	1,158	1,259
1,131	1,064	1,476	722	1,050	580	902
$ 28,114	$ 23,332	$ 21,921	$ 20,177	$ 21,579	$ 16,605	$ 16,221
$ 13,218	$ 10,748	$ 10,699	$ 9,686	$ 10,079	$ 7,535	$ 7,341
$ 352,838	$ 325,836	$ 280,345	$ 250,267	$ 234,919	$ 229,128	$ 216,903
$ 260,423	$ 240,825	$ 201,504	$ 177,053	$ 167,872	$ 166,846	$ 161,014
$ 381,557	$ 325,585	$ 295,980	$ 241,938	$ 222,058	$ 223,721	$ 222,229
$ 30,142	$ 49,154	$ 33,423	$ 17,830	$ 11,822	$ 13,836	$ 26,293
$ 119,576	$ 111,152	$ 84,757	$ 77,962	$ 72,939	$ 67,350	$ 67,517
63,256	71,050	58,991	66,190	69,416	73,408	48,409
$ 182,832	$ 182,202	$ 143,748	$ 144,152	$ 142,355	$ 140,758	$ 115,926
7,656	7,656	4,929	2,909	3,665	3,938	2,686
45,664	27,554	35,482	5,002	3,515	10,900	42,100
$ 236,152	$ 217,412	$ 184,159	$ 152,063	$ 149,535	$ 155,596	$ 160,712

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For the Years Ended December 31,	2010	2009[3]	2008
Common Stock Data and Ratios			
Basic earnings per share from continuing operations [1]	**$ 2.75**	$ 2.17	$ 2.00
Diluted earnings per share from continuing operations [1]	**$ 2.73**	$ 2.15	$ 1.98
Return on average equity from continuing operations [1]	**11.6%**	11.2%	11.2%
Common equity / total capitalization	**71.6%**	68.0%	58.7%
Common equity / total capitalization and short-term financing	**58.2%**	56.1%	49.4%
Book value per share	**$ 23.75**	$ 22.33	$ 18.03
Market price:			
High	**$ 42.200**	$ 35.000	$ 34.840
Low	**$ 28.010**	$ 22.020	$ 21.930
Close	**$ 41.520**	$ 32.050	$ 31.480
Average number of shares outstanding	**9,474,554**	7,313,320	6,811,848
Shares outstanding at year-end	**9,524,195**	9,394,314	6,827,121
Registered common shareholders	**2,482**	2,670	1,914
Cash dividends declared per share	**$ 1.31**	$ 1.25	$ 1.21
Dividend yield (annualized) [2]	**3.2%**	3.9%	3.9%
Payout ratio from continuing operations [1] [4]	**47.6%**	57.6%	60.5%
Additional Data			
Customers [5]			
Natural gas distribution	**120,230**	117,887	65,201
Electric distribution	**30,966**	31,030	
Propane distribution	**48,100**	48,680	34,981
Volumes[6]			
Natural gas deliveries (in Mcfs)	**41,795,438**	44,586,158	39,778,067
Electric Distribution (in MWHs)	**739,656**	105,739	
Propane distribution (in thousands of gallons)	**39,612**	32,546	27,956
Heating degree-days (Delmarva Peninsula)			
Actual HDD	**4,831**	4,729	4,431
10-year average HDD (normal)	**4,528**	4,462	4,401
Propane bulk storage capacity (in thousands of gallons)	**3,041**	3,042	2,471
Total employees [1] [7]	**734**	757	448

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

(2) 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.

(3) 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. These amounts also include the effects of acquisition accounting and issuance of Chesapeake common shares as a result of the merger. These amounts may not be indicative of future results due to the inclusion of merger effects. See Item 8 under the heading Notes to the Consolidated Financial Statements Note B, Acquisitions and Dispositions for additional discussions and presentation of pro forma results.

(4) 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.

(5) Customer data for 2009 includes 51,536, 31,030 and 13,651 of natural gas distribution, electric distribution and propane distribution customers, respectively, from FPU.

(6) Volumes data for 2009 includes 1,109,177 Mcfs, 105,739 MWHs and 1.1 million gallons for natural gas distribution, electric distribution and propane distribution, respectively, delivered by FPU from October 28, 2009 through December 31, 2009

(7) Total employees for 2009 include 332 FPU employees added to the Company upon the merger, effective October 28, 2009.

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2007	2006[8]	2005	2004	2003	2002	2001
$ 1.96	$ 1.78	$ 1.83	$ 1.68	$ 1.80	$ 1.37	$ 1.37
$ 1.94	$ 1.76	$ 1.81	$ 1.64	$ 1.76	$ 1.37	$ 1.35
11.5%	11.0%	13.2%	12.8%	14.4%	11.2%	11.1%
65.4%	61.0%	59.0%	54.1%	51.2%	47.8%	58.2%
50.6%	51.1%	46.0%	51.3%	48.8%	43.3%	42.0%
$ 17.64	$ 16.62	$ 14.41	$ 13.49	$ 12.89	$ 12.16	$ 12.45
$ 37.250	$ 35.650	$ 35.780	$ 27.550	$ 26.700	$ 21.990	$ 19.900
$ 28.000	$ 27.900	$ 23.600	$ 20.420	$ 18.400	$ 16.500	$ 17.375
$ 31.850	$ 30.650	$ 30.800	$ 26.700	$ 26.050	$ 18.300	$ 19.800
6,743,041	6,032,462	5,836,463	5,735,405	5,610,592	5,489,424	5,367,433
6,777,410	6,688,084	5,883,099	5,778,976	5,660,594	5,537,710	5,424,962
1,920	1,978	2,026	2,026	2,069	2,130	2,171
$ 1.18	$ 1.16	$ 1.14	$ 1.12	$ 1.10	$ 1.10	$ 1.10
3.7%	3.8%	3.7%	4.2%	4.2%	6.0%	5.6%
60.2%	65.2%	62.3%	66.7%	61.1%	80.3%	80.3%
62,884	59,132	54,786	50,878	47,649	45,133	42,741
34,143	33,282	32,117	34,888	34,894	34,566	35,530
34,820,050	34,321,160	34,980,939	31,429,494	29,374,818	27,934,715	27,263,542
29,785	24,243	26,178	24,979	25,147	21,185	23,080
4,504	3,931	4,792	4,553	4,715	4,161	4,368
4,376	4,372	4,436	4,389	4,409	4,393	4,446
2,441	2,315	2,315	2,045	2,195	2,151	1,958
445	437	423	426	439	455	458

(8) SFAS No. 123R (now codified within FASB ASC 718, 505 and 260) and SFAS No. 158 (codified within FASB ASC 715) were adopted in the year 2006; therefore, they were not applicable for the years prior to 2006.

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Management s Discussion and Analysis

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 on 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 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. Chesapeake s management uses gross margin in measuring its business units performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

In addition, certain information is presented, which, for comparison purposes, includes only FPU s results of operations or exclude FPU s results from the consolidated results of operations for the periods from the merger closing (October 28, 2009) to December 31, 2009 and in 2010. Certain other information is presented, which, for comparison purposes, excludes all merger-related costs incurred in connection with the FPU merger. Although the non-GAAP measures are not intended to replace the GAAP measures for evaluation of Chesapeake s performance, we believe that the portions of the presentation which include only the FPU results, or which exclude FPU s financial results for the post-merger period and merger-related costs provide a helpful comparative basis for investors to understand Chesapeake s performance.

The following discussion sometimes refers to legacy Chesapeake and words of similar import. Such terms and phrases mean our results, excluding the impacts from the FPU merger and merger-related costs

(a) Introduction

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

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

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

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

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

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

enhancing marketing channels to attract new customers;

providing reliable and responsive customer service to retain existing customers;

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

maintaining a consistent and competitive dividend for shareholders; and

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

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Management s Discussion and Analysis
(b) Highlights and Recent Developments
(in thousands except per share)

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Net income	**$ 26,056**	$ 15,897	$ 10,159	$ 15,897	$ 13,607	$ 2,290
Earnings per common stock diluted	**$ 2.73**	$ 2.15	$ 0.58	$ 2.15	$ 1.98	$ 0.17
Components of net income:						
Legacy Cheapeake	**$ 17,192**	$ 15,303	$ 1,889	$ 15,303	$ 14,299	$ 1,004
FPU	**9,339**	1,829	7,510	1,829		1,829
Merger-related costs	**(475)**	(1,235)	760	(1,235)	(692)	(543)
Total	**$ 26,056**	$ 15,897	$ 10,159	$ 15,897	$ 13,607	$ 2,290
Components of EPS diluted						
Legacy Chesapeake [1]	**$ 2.44**	$ 2.20	$ 0.24	$ 2.20	$ 2.08	$ 0.12
FPU[2]	**$ 0.34**	$ 0.12	$ 0.22	$ 0.12	$ 0.00	$ 0.12
Merger-related costs	**$ (0.05)**	$ (0.17)	$ 0.12	$ (0.17)	$ (0.10)	$ (0.07)
Total	**$ 2.73**	$ 2.15	$ 0.58	$ 2.15	$ 1.98	$ 0.17

(1) Calculated based on weighted average common shares outstanding for the period, which excludes the shares issued in the FPU merger.

(2) Represents the additional EPS generated by FPU s results since the merger.

On October 28, 2009, we completed a merger with FPU. The merger increased our overall presence in Florida by adding approximately 51,000 natural gas distribution customers and 12,000 propane distribution customers to our existing natural gas and propane distribution operations in Florida. We also now serve approximately 31,000 electric distribution customers in northwest and northeast Florida as a result of the merger. FPU s results have been included in our consolidated results since the completion of the merger.

Excluding the impacts from the FPU merger and merger-related costs, our diluted earnings per share from legacy Chesapeake businesses increased by 11 percent and six percent in 2010 and 2009, respectively, compared to the respective prior year.

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. Since FPU s results for the period prior to the merger were not included in our results, the year-over-year variances resulting from the factors described below as they relate to FPU are limited to the period after the merger.

Weather. We measure weather based on the number of heating degree-days (HDD) for the natural gas and propane distribution operations and the number of HDD and the number of cooling degree-days (CDD) for the electric distribution operation. We use historical averages as the normal weather for this analysis.

HDD on the Delmarva Peninsula in 2010 increased by 102, or two percent, compared to 2009, and by 303, or seven percent, compared to normal. HDD on the Delmarva Peninsula in 2009 increased by 298, or seven percent, compared to 2008, and by 267, or six percent, compared to normal. We estimate that colder weather contributed approximately $679,000 and $1.6 million in additional gross margin for our Delmarva natural gas and propane distribution operations in 2010 and 2009, respectively, compared to the respective prior year. We also estimate that the effect of the colder-than-normal temperatures on the Delmarva Peninsula in 2010 was increased gross margin of $1.6 million for our Delmarva natural gas and propane distribution operations.

Management s Discussion and Analysis

The colder temperatures in 2010 in Florida produced average HDD that were 590, or 65 percent, higher than 2009 and 582, or 63 percent, higher than normal. The average HDD in 2009 and 2008 were fairly consistent and did not fluctuate significantly from the normal weather. The warmer temperatures in the summer of 2010 also produced average CDD for the year that were 89, or three percent, higher than the prior year and 141, or five percent, higher than normal. We estimate that colder weather in the winter months and warmer weather in the summer months contributed approximately $1.4 million in additional gross margin for our Florida natural gas and electric distribution operations in 2010, compared to 2009.

Growth. Despite the continued slowdown in growth and overall economic conditions on the Delmarva Peninsula, our Delmarva natural gas distribution operations achieved two percent growth in average residential customers in both 2010 and 2009, compared to the respective prior year. These growth rates exceeded the industry s growth rates. In addition to the residential growth, in 2010, our Delmarva natural gas distribution operations added 10 large commercial and industrial customers with total expected annual margin of $748,000, as they were able to convert these customers to natural gas from other energy sources due to the pricing advantage of natural gas and its environmentally-friendly features. In total, customer growth for the Delmarva natural gas distribution operations generated additional margin of $1.1 million and $1.2 million in 2010 and 2009, respectively, compared to the respective prior year. The addition of certain industrial customers in 2010 also positioned us to further extend our natural gas distribution and transmission infrastructure in southern Delaware to serve other potential customers in the same area.

ESNG continued to expand its infrastructure and add new transportation services. The additional margin generated from the continued expansions and new services, net of the expired services, was $1.1 million and $1.8 million in 2010 and 2009, respectively, compared to the respective prior year. Although not affecting our results in 2010, ESNG completed the eight-mile mainline extension in December 2010 to interconnect with the TETLP pipeline. ESNG commenced its new transportation services to Chesapeake s Delaware and Maryland divisions in January 2011. The new transportation services have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, providing estimated annualized margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million thereafter.

FPU s natural gas distribution operation experienced growth in commercial and industrial customers in 2010, which contributed $196,000 in additional margin in 2010. Chesapeake s Florida natural gas distribution division experienced a slight growth in customers in 2010 after experiencing a net customer loss in 2009, including a loss of three large industrial customers, in Florida in late 2008 and 2009, which decreased its margin by $190,000 in 2009 compared to 2008. Customer growth in the Florida electric and propane distribution operations was flat.

Rates and Regulatory Matters. On January 14, 2010, new rates for Chesapeake s Florida natural gas distribution division became effective. The new rates for Chesapeake s Florida natural gas distribution division represented an annual rate increase of approximately $2.5 million and generated $2.3 million in increased margin in 2010, net of the impact from the interim rates in 2009, compared to 2009. An annual rate increase of approximately $8.0 million for FPU s natural gas distribution operation pursuant to the settlement agreement also became effective on January 14, 2010. The Florida PSC previously issued an Order in May 2009, approving a rate increase for FPU s natural gas distribution operation. The subsequent protest by the Office of Public Counsel of Florida led to this settlement agreement between the Office of Public Counsel and FPU, which the Florida PSC approved in December 2009.

Management s Discussion and Analysis

The merger with FPU and the purchase of the operating assets of IGC resulted in approximately $34.9 million in purchase premium, which we intend to seek the recovery through rates. We also intend to seek the recovery of approximately $2.2 million in merger-related costs attributed to the natural gas operations. Our Florida natural gas distribution operations are required to submit to the Florida PSC by April 29, 2011 data that details benefits, synergies, cost savings and cost increases resulting from the merger. We are currently in the process of discussing with the Office of Public Counsel and the Florida PSC staff the benefits and cost savings resulted from the merger, current and expected operating results of the regulated operations in Florida, and recovery of the purchase premium and merger-related costs. Our results in 2010 reflect an accrual of $750,000 by FPU s natural gas distribution operation for the regulatory risk associated with its earnings, merger benefits and recovery of purchase premium and merger-related costs. Also reflected in our 2010 results were approximately $75,000 of the costs associated with these discussions, which were expensed in 2010.

Although not affecting our results in 2010, ESNG filed a proposed rate increase with the FERC on December 30, 2010. ESNG expects this base rate proceeding to be completed in 2011. ESNG expensed approximately $147,000 in costs associated with this filing in 2010.

Propane Prices. A sharp decline in propane prices in the winter months when our propane inventory is at its highest level exposes us to inventory valuation risk as GAAP requires us to re-value the propane inventory using the lower-of-cost-or-market approach. We have implemented various propane supply and inventory strategies to hedge such risk. In late 2008, a sharp decline in propane prices resulted in inventory and swap valuation adjustments of $1.8 million in 2008, which lowered the propane inventory cost of our Delmarva propane distribution operation during the first half of 2009. The absence of similar inventory valuation adjustments in 2009 and increased margin generated from the low propane cost during the first half of 2009, coupled with sustained retail prices, contributed to increased gross margin of $3.5 million in 2009 compared to 2008 for the Delmarva propane distribution operation. Retail margins returned to more normal levels in 2010.

Continued lack of volatility in wholesale propane prices reduced the opportunities for our propane wholesale marketing subsidiary, Xeron, and decreased its trading volume by 13 percent and 57 percent in 2010 and 2009, respectively, compared to the respective prior year. The lower volumes reduced gross margin by approximately $441,000 and $1.0 million for 2010 and 2009, respectively, over the prior year.

Natural Gas Spot Sale Opportunities. Our unregulated natural gas marketing subsidiary, PESCO, entered into spot sales in 2009 with a refinery on the Delmarva Peninsula, which contributed significantly to PESCO s gross margin increase of $1.0 million in 2009. The absence of spot sales opportunities to the same customer in 2010 reduced PESCO s margin in 2010, compared to 2010. Spot sales are not predictable, and, therefore, are not included in our long-term financial plans or forecasts.

Interest Rates. We continued to experience low short-term interest rates throughout 2010 and 2009 as our short-term weighted average interest rate approximated 1.77 percent in 2010, 1.28 percent in 2009, and 2.79 percent in 2008. The level of our short-term borrowings in 2010 increased over 2009 as we used a new short-term term loan facility to finance the redemption of $29.1 million of FPU s 6.85 percent and 4.90 percent secured first mortgage bonds prior to their respective maturities. The level of our short-term borrowings in 2009 was reduced by the placement of $30.0 million of 5.93 percent unsecured senior notes in October 2008 and a decline in working capital requirements due to lower commodity prices, lower trading volume by the propane wholesale marketing subsidiary, lower income tax payments from bonus depreciation and the timing of our capital expenditures.

Management s Discussion and Analysis

Advanced Information Services. Our advanced information services subsidiary, BravePoint, generated $759,000 in operating income in 2010, compared to an operating loss of $229,000 in 2009. Increased billable consulting hours in 2010 and cost containment actions implemented throughout 2009 contributed to the increased operating results.

(c) Critical Accounting Policies

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 discussed with 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, 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 A, Summary of Accounting Policies, we have recorded regulatory assets of $23.9 million and regulatory liabilities of $47.8 million, at December 31, 2010. If we were required to terminate application of this Topic, 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 P, Environmental Commitments and Contingencies, we have completed our responsibilities related to one environmental site and are currently participating in the investigation, assessment or remediation of seven other former MGP sites. Amounts have been recorded as environmental liabilities and associated environmental regulatory assets based on estimates of future costs provided by independent consultants. 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.

Since we believe that recovery of these expenditures, including any litigation costs, is probable through the regulatory process, we have recorded a regulatory asset and corresponding environmental liability. At December 31, 2010, we have recorded environmental regulatory and other assets of $7.5 million and a liability of $12.0 million for environmental costs.

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Management s Discussion and Analysis

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 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, 2010 and 2009:

During 2010 and 2009, 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.

During 2010 and 2009, the propane distribution operation entered into a put option to protect it from the impact of price decreases on the Pro-Cap (propane price-cap) Plan that we offer to customers. We accounted for the put option on a mark-to-market basis and recorded a loss of $168,000 and $41,000, at December 31, 2010 and 2009, respectively.

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 Statement of Income as revenue or expense. These contracts generally mature within one year and are almost exclusively for propane commodities. For the years ended December 31, 2010 and 2009, these contracts had net unrealized gains of $284,000 and net unrealized losses of $1.6 million, respectively.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSCs of the jurisdictions in which we operate. The natural gas transmission operation 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 ESNG 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. In connection with this accrual, we must estimate amounts of natural gas and electricity that have not been accounted for on our delivery systems and must 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 our statement of income. For certain propane distribution customers without meters and advanced information services customers, we record revenue in the period the products are delivered and/or services are rendered.

Management s Discussion and Analysis

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 purchased 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 purchased fuel costs 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 is 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 experiences, 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.

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 M, 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.

The total pension and other postretirement benefit costs included in operating income were $2.0 million, $892,000 and $537,000, in 2010, 2009 and 2008, respectively. We expect to record pension and postretirement benefit costs of approximately $2.0 million for 2011, of which $455,000 are settlement losses related to lump-sum distributions we expect to make during 2011, from the Chesapeake Pension Plan and the Chesapeake SERP related to the retirement of our former Chief Executive Officer, who retired in January 2011. Actuarial assumptions affecting 2011 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 5.00 percent and 5.25 percent for Chesapeake s plans and FPU s plans, respectively. The discount rate for each plan was determined by management considering high quality corporate bond rates based on Moody s Aa bond index, the Citigroup yield curve, changes in those rates from the prior year, and other pertinent factors, such as the expected lives of the plans and 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 increase in the discount rate could decrease our pension and postretirement costs by approximately $98,000 and a decrease of 0.25 percent could increase our pension and postretirement costs by $123,000. A 0.25 percent increase in the rate of return would decrease our pension cost by approximately $112,000, and a decrease of 0.25 percent could increase our pension cost by approximately $117,000 and will not have an impact on postretirement and SERP plans because these plans are not funded.

Management s Discussion and Analysis

Acquisition Accounting

The merger with FPU and other acquisitions were accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer. The acquisition method of accounting requires, among other things, that the assets acquired and liabilities assumed in the merger be recognized at their fair value as of the acquisition date. It also establishes that the consideration transferred be measured at the closing date of the merger at the then-current market price. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In addition, market participants are assumed to be buyers and sellers in the principal (or the most advantageous) market for the asset or liability and fair value measures for an asset assume the highest and best use by those market participants, rather than our intended use of those assets. In estimating the fair value of the assets and liabilities subject to rate regulation, we considered the nature of the assets and liabilities and the regulatory mechanism for recovery, to which these assets and liabilities are subject, as a factor in determining their appropriate fair value. We also considered the existence of a regulatory process that would allow, or sometimes require, regulatory assets and liabilities to be established to offset the fair value adjustment to certain assets and liabilities subject to rate regulation. If a regulatory asset or liability should be established to offset the fair value adjustment based on the current regulatory process, as was the case for fuel contracts and long-term debt, we did not gross-up our balance sheet to reflect the fair value adjustment and corresponding regulatory asset/liability, because such gross-up would not have resulted in a change to our value of net assets and future earnings.

The acquisition method of accounting also requires acquisition-related costs to be expensed in the period in which those costs are incurred, rather than including them as a component of consideration transferred. It also prohibits an accrual of certain restructuring costs at the time of the merger for the acquiree. As we intend to seek recovery in future rates in Florida of a certain portion of the purchase premium paid and merger-related costs incurred, we also considered the impact of ASC Topic 980, Regulated Operations, in determining proper accounting treatment for the merger-related costs. We deferred a certain portion of the total costs incurred as a regulatory asset, which represents our best estimate of the costs, which we expect to be permitted to recover when we complete the appropriate rate proceedings based on similar proceedings in Florida in the past. The remaining costs have been expensed.

(d) Results of Operations

(in thousands except per share)

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Business Segment:						
Regulated Energy	**$ 43,509**	$ 26,900	$ 16,609	$ 26,900	$ 24,733	$ 2,167
Unregulated Energy	**7,908**	8,158	(250)	8,158	3,781	4,377
Other	**513**	(1,322)	1,835	(1,322)	(35)	(1,287)
Operating Income	**51,930**	33,736	18,194	33,736	28,479	5,257
Other Income	**195**	165	30	165	103	62
Interest Charges	**9,146**	7,086	2,060	7,086	6,158	928
Income Taxes	**16,923**	10,918	6,005	10,918	8,817	2,101
Net Income	**$ 26,056**	$ 15,897	$ 10,159	$ 15,897	$ 13,607	$ 2,290
Earnings Per Share of Common Stock						
Basic	**$ 2.75**	$ 2.17	$ 0.58	$ 2.17	$ 2.00	$ 0.17

Diluted	**$**	**2.73**	$	2.15	$	0.58	$	2.15	$	1.98	$	0.17

Management s Discussion and Analysis

2010 compared to 2009

Our net income increased by approximately $10.2 million, or $0.58 per share (diluted) in 2010, compared to 2009. Chesapeake s legacy businesses, which exclude the FPU business and merger-related costs, generated an increase in net income of $1.9 million, or $0.24 per share (diluted) in 2010. The $0.24 per share increase in diluted earnings per share by Chesapeake s legacy businesses in 2010, which is calculated based on weighted average common shares outstanding, exclusive of the shares issued in the FPU merger, represents 11-percent growth from 2009. Continued growth and expansions of our natural gas distribution and transmission businesses and propane distribution business on the Delmarva Peninsula, the rate increase in Chesapeake s Florida natural gas distribution division, favorable weather impact and improved results in our advanced information services business contributed to this increase. These increases were partially offset by a decline in earnings from our natural gas marketing business, due primarily to the absence of spot sales to one industrial customer, and our propane wholesale marketing business. FPU s results, which have been included in our consolidated results since the completion of the merger on October 28, 2009, added $7.5 million to our consolidated net income in 2010, which generated an increase of $0.22 per share (diluted) in 2010. A decrease in FPU merger-related costs also added $0.12 per share (diluted) to the increase in 2010.

The following table illustrates the effect of the merger on our results for the year ended December 31, 2010 and December 31, 2009.

	2010			2009		
For the Years Ended December 31,	**Chesapeake, excluding FPU**	**FPU**	**Chesapeake Total**	**Chesapeake, excluding FPU**	**FPU[1]**	**Chesapeake Total**
(in thousands)						
Operating Income (Loss)						
Regulated Energy	**$ 26,711**	**$ 16,798**	**$ 43,509**	$ 23,908	$ 2,992	$ 26,900
Unregulated Energy	**6,335**	**1,573**	**7,908**	7,605	553	8,158
Other, including merger-related costs	**513**		**513**	(1,322)		(1,322)
Operating Income	**33,559**	**18,371**	**51,930**	30,191	3,545	33,736
Other Income, net of expenses	**48**	**147**	**195**	58	107	165
Interest Charges	**5,752**	**3,394**	**9,146**	6,345	741	7,086
Income Taxes	**11,138**	**5,785**	**16,923**	9,836	1,082	10,918
Net Income	**$ 16,717**	**$ 9,339**	**$ 26,056**	$ 14,068	$ 1,829	$ 15,897

(1) FPU operating results are for the period from the merger closing (October 28, 2009) to December 31, 2009

2009 compared to 2008

Our net income increased by approximately $2.3 million, or $0.17 per share (diluted), in 2009, compared to 2008. Excluding FPU s results and the merger-related costs, Chesapeake s legacy businesses generated an increase in net income of $1.0 million, or $0.12 per share (diluted) in 2009. This increase in the diluted earnings per share, which is calculated based on weighted average common shares outstanding, exclusive of the shares issued in the FPU merger, represents five-percent growth in 2009. Continued growth and expansions in our natural gas distribution and transmission businesses on the Delmarva Peninsula, and increased retail margins in the propane distribution business, favorable weather impact and spot sale opportunities by our natural gas marketing business contributed to this increase. FPU s net income included in our consolidated results in 2009, which represents its net income since the completion of the merger, was $1.8 million, generating an additional $0.12 per share (diluted).

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Management s Discussion and Analysis

The following table illustrates the effect of the merger on our results for the year ended December 31, 2009 and the results in 2008.

	2009			2008		
For the Years Ended December 31, *(in thousands)*	**Chesapeake, excluding FPU**	**FPU(1)**	**Chesapeake Total**	**Chesapeake, excluding FPU**	**FPU**	**Chesapeake Total**
Operating Income (Loss)						
Regulated Energy	**$ 23,908**	**$ 2,992**	**$ 26,900**	$ 24,733	$ 0	$ 24,733
Unregulated Energy	**7,605**	**553**	**8,158**	3,781		3,781
Other	**(1,322)**		**(1,322)**	(35)		(35)
Operating Income	**30,191**	**3,545**	**33,736**	28,479	0	28,479
Other Income, net of expenses	**58**	**107**	**165**	103		103
Interest Charges	**6,345**	**741**	**7,086**	6,158		6,158
Income Taxes	**9,836**	**1,082**	**10,918**	8,817		8,817
Net Income	**$ 14,068**	**$ 1,829**	**$ 15,897**	$ 13,607	$ 0	$ 13,607

(1) FPU operating results are for the period from the merger closing (October 28, 2009) to December 31, 2009

Management s Discussion and Analysis
Regulated Energy

For the Years Ended December 31, *(in thousands)*	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Revenue	**$ 269,934**	$ 139,099	$ 130,835	$ 139,099	$ 116,468	$ 22,631
Cost of sales	**144,217**	64,803	79,414	64,803	54,789	10,014
Gross margin	**125,717**	74,296	51,421	74,296	61,679	12,617
Operations & maintenance	**56,338**	32,569	23,769	32,569	25,369	7,200
Depreciation & amortization	**17,038**	8,866	8,172	8,866	6,694	2,172
Other taxes	**8,832**	5,961	2,871	5,961	4,883	1,078
Other operating expenses	**82,208**	47,396	34,812	47,396	36,946	10,450
Operating Income	**$ 43,509**	$ 26,900	$ 16,609	$ 26,900	$ 24,733	$ 2,167

Weather and Customer Analysis

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Delmarva Peninsula						
Actual HDD	**4,831**	4,729	102	4,729	4,431	298
10-year average HDD	**4,528**	4,462	66	4,462	4,401	61
Estimated gross margin per HDD	**$ 1,995**	$ 2,429	$ (434)	$ 2,429	$ 1,937	$ 492
Florida						
Actual HDD	**1,501**	911	590	911	851	60
10-year average HDD	**919**	863	56	863	848	15
Actual CDD	**2,859**	2,770	89	2,770	2,553	217
10-year average CDD	**2,718**	2,694	24	2,694	2,687	7
Average number of residential customers						
Delmarva natural gas distribution	**47,638**	46,717	921	46,717	45,570	1,147
Florida natural gas distribution[(1)]	**61,053**	60,048	1,005	60,048	13,373	46,675
Florida electric distribution [(1)]	**23,589**	23,679	(90)	23,679		23,679
Total	**132,280**	130,444	1,836	130,444	58,943	71,501

(1) Average number of residential customers for FPU are included in 2010 and 2009.

2010 Compared to 2009

Operating income for the regulated energy segment increased by approximately $16.6 million, or 62 percent, in 2010, compared to 2009, which was generated from a gross margin increase of $51.4 million, offset partially by an operating expense increase of $34.8 million. Our 2010 results include 12 months of FPU s results, whereas 2009 includes only two months.

Gross Margin

Gross margin for our regulated energy segment increased by $51.4 million, or 69 percent. Of the $51.4 million increase, Chesapeake s legacy regulated energy businesses generated $5.2 million of the increase, or 10 percent. FPU s natural gas and electric distribution operations contributed $46.2 million of this increase. FPU s results in 2009 have been included in our results since the completion of the merger on October 28, 2009. Our results for 2010 included FPU s results for the full year.

Management s Discussion and Analysis

The natural gas distribution operations for the Delmarva Peninsula generated an increase in gross margin of $1.4 million in 2010. The factors contributing to this increase were as follows:

$1.1 million of the gross margin increase was a result of a two-percent increase in residential customers as well as additional growth in commercial and industrial customers on the Delmarva Peninsula. Residential, commercial and industrial growth by our Delaware division generated $525,000, $163,000 and $313,000, respectively, of the gross margin increase, and the customer growth by our Maryland division contributed $97,000 to the gross margin increase. In 2010, our Delmarva natural gas distribution operations also added 10 large commercial and industrial customers with total expected annualized margin of $748,000, of which $196,000 has been reflected in 2010 s results. The addition of certain industrial customers in 2010 also positioned us to further extend our natural gas distribution and transmission infrastructure in southern Delaware to serve other potential customers in the same area.

Colder weather on the Delmarva Peninsula generated an additional $365,000 to gross margin as heating degree-days increased by 102, or two percent, in 2010, compared to 2009. This increased gross margin is primarily related to our Delaware division, as residential heating rates for our Maryland division are weather-normalized, and we typically do not experience an impact on gross margin from the weather for our residential customers in Maryland.

A decline in non-weather-related customer consumption, primarily by residential customers of our Delaware division, decreased gross margin by $111,000.

Our Florida natural gas distribution operations experienced an increase in gross margin of $33.5 million in 2010. The factors contributing to this increase were as follows:

FPU s natural gas distribution operation generated $37.1 million in gross margin for 2010, which includes $148,000 of gross margin generated by the purchase of operating assets from IGC whose operating assets were purchased by FPU on August 9, 2010. Included in gross margin from FPU s natural gas distribution operation in 2009 was $6.4 million. Gross margin from FPU s natural gas distribution operation in 2010 was positively affected by an annual rate increase of approximately $8.0 million, effective January 14, 2010, colder temperatures in Florida and growth in commercial and industrial customers. Included in gross margin from FPU s natural gas distribution operation was the impact of a $750,000 accrual related to the regulatory risk associated with its earnings, merger benefits and recovery of purchase premium. FPU is required to detail known benefits, synergies, cost savings and cost increases resulting from the merger and present the information in the come-back filing to the Florida PSC by April 29, 2011 (within 18 months of the merger). We are currently in discussions with the Office of Public Counsel and the Florida PSC staff regarding the benefits and cost savings of the merger, current and expected earnings levels as well as the recovery of approximately $34.9 million in purchase premium and $2.2 million in merger-related costs. We recorded this accrual based on our assessment of FPU s current earnings, the regulatory environment in Florida and progress of the current discussions.

Gross margin from Chesapeake s Florida division increased by $2.9 million, primarily as a result of an annual rate increase of approximately $2.5 million, which became effective on January 14, 2010. The colder temperatures in 2010 also generated an additional $247,000 in gross margin in 2010, compared to 2009.

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Management s Discussion and Analysis

The natural gas transmission operations achieved gross margin growth of $952,000 in 2010. The factors contributing to this increase were as follows:

New transportation services implemented by ESNG in November 2009, May 2010 and November 2010 as a result of its system expansion projects generated an additional $1.1 million to gross margin in 2010, compared to 2009. These expansion projects added 9,623 Mcfs of service per day with estimated annual gross margin of $1.6 million, of which $1.2 million has been reflected in 2010 s results.

New firm transportation service for an industrial customer for the period from November 2009 to October 2012 provided an additional 9,662 Mcfs per day for the period January 1, 2010 through February 5, 2010, and an additional 2,705 Mcfs per day for the period February 6, 2010 through October 31, 2010. These new services added $329,000 to gross margin for 2010. Partially offsetting the additional gross margin generated by this new firm transportation service was the margin of $232,000 in 2009 from the temporary interruptible service provided to the same customer. This temporary increase in service did not occur in 2010.

ESNG changed its rates effective April 2009 to recover specific project costs in accordance with the terms of precedent agreements with certain customers. These rates generated $508,000 and $381,000 in gross margin in 2010 and 2009, respectively. ESNG and the customers agreed to shorten the recovery period, starting in March 2011.

Offsetting the foregoing increases to gross margin, ESNG received notices from two customers of their intentions not to renew their firm transportation service contracts, which expired in November 2009 and April 2010, decreasing gross margin by $341,000 for 2010.

Although not affecting our results in 2010, ESNG completed the eight-mile mainline extension in December 2010 to interconnect with the TETLP pipeline. ESNG commenced its new transportation services to Chesapeake s Delaware and Maryland divisions in January 2011. These new services have a three-year phase-in from 19,324 Mcfs per day to 38,647 Mcfs per day, providing estimated gross margin of $2.4 million in 2011, $3.9 million in 2012 and $4.3 million thereafter.

Our Florida electric distribution operation, which was acquired in the FPU merger, generated gross margin of $18.4 million in 2010, compared to $2.8 million in gross margin generated in 2009. FPU s results in 2009 were included in our results only after the completion of the merger in 2009. Gross margin from our electric distribution operation was positively affected by colder temperatures in the winter months and warmer temperatures in the summer months in 2010.

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $34.8 million, or 73 percent, in 2010, of which $32.4 million was related to other operating expenses of FPU. The remaining increase of $2.4 million or a five percent increase from other operating expenses in 2009, exclusive of other operating expenses of FPU, was due primarily to the following factors:

Payroll and benefits increased by $705,000 due primarily to annual salary increases and incentive pay as a result of improved performance.

Depreciation and asset removal costs increased by $518,000 as a result of our increased capital investments made in 2010 and 2009 to support growth.

Regulatory expenses increased by $349,000 due primarily to costs associated with ESNG s recent rate case filing and ongoing regulatory discussions involving the merger impact and recovery of the purchase premium in Florida.

Non-income-taxes increased by $63,000 due primarily to increased gross receipt tax.

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Management s Discussion and Analysis

2009 Compared to 2008

Operating income for the regulated energy segment increased by approximately $2.2 million, or nine percent, in 2009, compared to 2008, which was generated from a gross margin increase of $12.6 million, offset partially by an operating expense increase of $10.4 million.

Gross Margin

Gross margin for our regulated energy segment increased by $12.6 million, or 20 percent. FPU s natural gas and electric distribution operations had $9.2 million in gross margin for the period from the merger closing (October 28, 2009) to December 31, 2009, which contributed to this increase.

The natural gas distribution operations for the Delmarva Peninsula generated an increase in gross margin of $1.3 million in 2009. The factors contributing to this increase were as follows:

- The Delmarva natural gas distribution operations experienced growth in residential, commercial, and industrial customers, which contributed $471,000, $149,000 and $589,000, respectively, to the gross margin increase, in spite of the continued slowdown in the new housing construction and industrial growth in the region. A two-percent residential customer growth experienced by the Delmarva natural gas distribution operation in 2009 was lower than the growth experienced in recent years.

- Colder weather on the Delmarva Peninsula contributed $449,000 to the increased gross margin, as HDD increased by 298, or seven percent, compared to 2008.

- The Delaware division s new rate structure allows collection of miscellaneous service fees of $256,000, which, although not representing additional revenue, were previously offset against other operating expenses.

- Interruptible sales to industrial customers decreased in 2009 due to a reduction in the price of alternative fuels, which reduced gross margin by $355,000.

- Non-weather related customer consumption decreased in 2009, which reduced gross margin by $187,000.

Chesapeake s Florida natural gas distribution operation experienced a decrease in gross margin of $333,000, in 2009. This decrease was attributable to reduced consumption by residential and non-residential customers and the loss of three industrial customers, one in 2008 and two in 2009, due to adverse economic conditions in the region. This decrease was partially offset by an increase in gross margin of $99,000 due to implementation of interim natural gas rates in the third quarter of 2009.

The natural gas transmission operations achieved gross margin growth of $2.5 million in 2009. The factors contributing to this increase were as follows:

- New long-term transmission services implemented by ESNG in November of 2008 and 2009, which provided for an additional 5,459 Mcfs per day and 3,976 Mcfs per day, respectively, added $939,000 to gross margin in 2009.

- New firm transmission services provided to an industrial customer for the period of February 6, 2009 through October 31, 2009, provided for an additional 6,957 Mcfs per day and added $574,000 to gross margin. In addition, ESNG entered into two additional firm transmission service agreements with this customer for: (1) 6,006 Mcfs per day from November 1, 2009 through November 30, 2009, which added $56,000 to gross margin for 2009; and (2) 9,662 Mcfs per day from November 1, 2009 through October 31, 2012, which added $181,000 to gross margin in 2009. These services generate annual gross margin of $1.1 million.

- In April 2009, ESNG changed its rates to recover specific project costs in accordance with the terms of precedent agreements with certain customers. These new rates generated $381,000 in gross margin for 2009 and will contribute $516,000 annually thereafter for a period of 20 years.

During January 2009, PIPECO, our intrastate pipeline subsidiary in Florida, began to provide natural gas transmission service to a customer under a 20-year contract. This agreement contributed $264,000 to gross margin in 2009.

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Management s Discussion and Analysis

Other Operating Expenses

Other operating expenses for the regulated energy segment increased by $10.4 million, of which $6.2 million was related to other operating expenses of FPU for the period from the merger closing (October 28, 2009) to December 31, 2009. The remaining increase in other operating expenses was due primarily to the following factors:

Depreciation expense, asset removal costs and property taxes, collectively, increased by approximately $1.4 million as a result of our continued capital investments to support customer growth. Depreciation expense for 2008 also includes a $305,000 depreciation credit as a result of the Delaware negotiated rate settlement agreement in the third quarter of 2008, of which $295,000 was related to depreciation for the months of October through December 2007.

Salaries and incentive compensation increased by $803,000, due primarily to compensation adjustments implemented on January 1, 2009 for non-executive employees, based on a compensation survey completed in the fourth quarter of 2008, and annual salary increases, coupled with a slight increase in the accrual for incentive compensation.

The allowance for uncollectible accounts in the natural gas operation increased by $176,000 due to growth in customers and the general economic climate.

Benefit costs increased by $373,000, due primarily to higher pension costs as a result of the decline in the value of pension assets in 2008 and other benefit costs relating to increased payroll costs.

Increased information technology spending to continuously enhance our information technology infrastructure and level of support generated increased costs of $285,000.

Corporate overhead allocated to the regulated energy segment increased by approximately $722,000 due to the overall increase in corporate overhead costs. This increase was related primarily to increased payroll and benefits and increased costs associated with investor relations and financial reporting activities.

Unregulated Energy

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
(in thousands)						
Revenue	**$ 146,793**	$ 119,973	$ 26,820	$ 119,973	$ 161,290	$ (41,317)
Cost of sales	**110,680**	90,408	20,272	90,408	138,302	(47,894)
Gross margin	**36,113**	29,565	6,548	29,565	22,988	6,577
Operations & maintenance	**23,140**	18,016	5,124	18,016	16,322	1,694
Depreciation & amortization	**3,433**	2,415	1,018	2,415	2,024	391
Other taxes	**1,632**	976	656	976	861	115
Other operating expenses	**28,205**	21,407	6,798	21,407	19,207	2,200
Operating Income	**$ 7,908**	$ 8,158	$ (250)	$ 8,158	$ 3,781	$ 4,377

Weather Analysis Delmarva

For the Years Ended December 31,	2010	2009	Increase (decrease)	2009	2008	Increase (decrease)
Actual HDD	**4,831**	4,729	102	4,729	4,431	298
10-year average HDD	**4,528**	4,462	66	4,462	4,401	61
Estimated gross margin per HDD	**$ 2,415**	$ 3,083	$ (668)	$ 3,083	$ 2,465	$ 618

Management s Discussion and Analysis

2010 Compared to 2009

Operating income for the unregulated energy segment decreased by approximately $250,000, or three percent, in 2010 compared to 2009, which was attributable to an increase in gross margin of $6.5 million, offset by an increase in other operating expenses of $6.8 million. A decline in operating income for the unregulated energy segment is largely attributable to the natural gas marketing business, which experienced a decrease in gross margin due primarily to the absence of spot sales to one industrial customer.

Gross Margin

Gross margin for our unregulated energy segment increased by $6.5 million, or 22 percent, for 2010, compared to the same period in 2009.

Our Delmarva propane distribution operation generated a gross margin increase of $1.0 million, as a result of the following factors:

Retail volumes sold increased by 1.6 million gallons, or seven percent, in 2010, which generated additional gross margin of $1.1 million. The addition of 436 community gas system customers and 1,000 other customers acquired in February 2010 as part of the purchase of the operating assets of a propane distributor serving Northampton and Accomack Counties in Virginia contributed approximately 38% of this increase. The two-percent colder weather in 2010, compared to 2009, generated additional margin of $314,000. Timing of propane deliveries to our bulk customers contributed to the remaining increase in gross margin due to an increase in retail volumes.

Other fees increased by $340,000 in 2010 driven by increased customer participation in various customer pricing programs.

Retail margin per gallon decreased in 2010, compared to 2009, and decreased gross margin by $399,000. Retail margin during the first half of 2009 benefited from the inventory valuation adjustment recorded in late 2008 which lowered the propane inventory costs and, therefore, increased retail margins during the first half of 2009. Retail margins for the second half of 2010 returned to more normal levels. Retail margins in the second half of 2010 increased from the same period in 2009, partially offsetting the impact of the decrease in the first half of the year.

Our Florida propane distribution operation generated $9.4 million in 2010, compared to $3.2 million in 2009. The 2009 results include FPU s results for the two months after the completion of the merger. Also included in the gross margin increase for 2010 was approximately $767,000 in increased merchandise sales from FPU.

Gross margin for Xeron, our propane wholesale marketing operation, decreased by $441,000 in 2010 compared to 2009. Xeron s trading volumes decreased by 13 percent in 2010 compared to 2009.

In 2010, gross margin for our unregulated natural gas marketing subsidiary, PESCO, decreased by $1.0 million. In 2009, PESCO benefited from increased spot sales on the Delmarva Peninsula. Spot sales decreased in 2010, due primarily to one industrial customer. Spot sales are not predictable and, therefore, are not included in our long-term financial plans or forecasts.

Other Operating Expenses

Total other operating expenses for the unregulated energy segment increased by $6.8 million in 2010. The Florida distribution operation and FPU s merchandise activities contributed $6.0 million to this increase. Included in other operating expenses for the Florida propane distribution operation in 2010 was approximately $370,000 expensed in the third and fourth quarters of 2010 for the settlement of a class action complaint (See Item 8 under the heading Notes to the Consolidated Financial Statements Note Q, Other Commitments and Contingencies). The remaining increase of $771,000 in other operating expenses was due primarily to increased payroll and benefit costs, higher non-income taxes due to increased sales taxes and increased propane delivery costs, partially offset by a decrease in bad debt expenses as a result of expanded credit and collection initiatives by PESCO.

Management s Discussion and Analysis

2009 compared to 2008

Operating income for the unregulated energy segment increased by approximately $4.4 million in 2009 compared to 2008, which was attributable to a gross margin increase of $6.6 million, offset partially by an operating expense increase of $2.2 million.

Gross Margin

Gross margin for our unregulated energy segment increased by $6.6 million, or 29 percent, in 2009 compared to 2008. FPU s propane distribution operation contributed $1.8 million to gross margin during the period from the merger closing (October 28, 2009) to December 31, 2009.

PESCO, our natural gas marketing operation, experienced an increase in gross margin of $1.0 million in 2009. PESCO increased its sales volumes by 13 percent in 2009 compared to 2008, as it benefited from increased spot sale opportunities on the Delmarva Peninsula during 2009, which contributed significantly to the gross margin increase. Spot sales are opportunistic and unpredictable, and their future availability is highly dependent upon market conditions.

The propane distribution operation, excluding FPU, increased its gross margin by $4.8 million. The absence of inventory valuation adjustments in 2009 and lower propane costs, coupled with sustained retail prices, contributed $3.5 million of the gross margin increase. A sharp decline in propane prices in late 2008 resulted in a loss associated with the inventory and swap valuation adjustments of $1.8 million in 2008. These inventory adjustments in 2008 and relatively low propane prices during the first half of 2009 enabled the Delmarva propane distribution operation to keep its propane cost low. Colder weather on the Delmarva Peninsula in 2009 increased gross margin by $1.2 million, as temperatures were seven percent colder in 2009, compared to 2008. Gross margin for the Florida propane distribution operation in 2009 remained unchanged from 2008 as increased margins per retail gallon were offset by a decline in residential and non-residential consumption.

The propane wholesale marketing operation experienced a reduction in gross margin of $1.0 million in 2009. The propane wholesale marketing operation typically capitalizes on price volatility by selling at prices above cost and effectively managing the larger spreads between the market (spot) prices and forward prices. Overall lack of volatility in wholesale propane prices in 2009, compared to 2008, reduced such revenue opportunities and its trading volume by 57 percent.

Other Operating Expenses

Total other operating expenses for the unregulated energy segment increased by $2.2 million in 2009, of which $1.2 million was related to other operating expenses of FPU during the period from the merger closing (October 28, 2009) to December 31, 2009. The remaining increase in other operating expenses was due primarily to the following factors:

- Payroll costs increased by $301,000 in 2009 compared to 2008 due to annual salary increases.
- Benefit costs increased by $167,000, due primarily to increased pension costs in 2009 as a result of the decline in the value of pension plan assets.
- Depreciation expense increased by $249,000 as we continued to make capital investments in the propane distribution operations.
- Additional costs of approximately $115,000 were incurred in 2009 to maintain propane tanks.
- Corporate overhead costs allocated to the unregulated energy segment increased by approximately $568,000 due to the overall increase in administrative payroll and benefits and increased costs associated with investor relations and financial reporting activities.
- These increases were partially offset by lower vehicle-related costs of $176,000, due primarily to a decrease in the cost of fuel.

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Management s Discussion and Analysis
Other

For the Years Ended December 31,	**2010**	**2009**	**Increase (decrease)**	**2009**	**2008**	**Increase (decrease)**
(in thousands)						
Revenue	**$ 13,142**	$ 11,998	$ 1,144	$ 11,998	$ 15,373	$ (3,375)
Cost of sales	**6,316**	6,036	280	6,036	8,034	(1,998)
Gross margin	**6,826**	5,962	864	5,962	7,339	(1,377)
Operations & maintenance	**4,766**	4,859	(93)	4,859	5,206	(347)
Transaction-related costs	**660**	1,478	(818)	1,478	1,153	325
Depreciation & amortization	**289**	310	(21)	310	290	20
Other taxes	**600**	640	(40)	640	728	(88)
Other operating expenses	**6,315**	7,287	(972)	7,287	7,377	(90)
Operating Income Other	**511**	(1,325)	1,836	(1,325)	(38)	(1,287)
Operating Income Eliminations	**2**	3	(1)	3	3	
Operating Income	**$ 513**	$ (1,322)	1,835	$ (1,322)	$ (35)	$ (1,287)

2010 Compared to 2009

Operating income for the Other segment increased by approximately $1.8 million in 2010, compared to 2009. The increase in operating income was attributable to a gross margin increase of $864,000 and a $972,000 decrease in operating expenses.

Gross margin

The period-over-period increase in gross margin of $864,000 for our Other segment was generated by our advanced information services subsidiary s increase in revenue and gross margin from its professional database monitoring and support solution services and higher consulting revenues as a result of a seven-percent increase in the number of billable consulting hours in 2010 compared to 2009.

Operating expenses

Other operating expenses decreased by $972,000 in 2010 compared to 2009. The decrease in operating expenses was attributable primarily to an $818,000 decrease in merger-related costs expensed in 2010 compared to 2009.

2009 compared to 2008

Operating loss for the Other segment increased by approximately $1.3 million in 2009 compared to 2008. The increased loss was attributable primarily to the gross margin decrease of $1.4 million in the advanced information services operation.

Gross margin

The period-over-period decrease in gross margin for the Other segment was a result of a decrease in consulting revenues by the advanced information services subsidiary due primarily to a 28-percent decrease in the number of billable consulting hours, coupled with a decline in training revenues. The reduction in the number of billable consulting hours was a result of economic conditions. The decrease in consulting revenues was partially offset by an increase of $218,000 from BravePoint s professional database monitoring and support solution services, and increased product sales of $140,000.

Management s Discussion and Analysis

Operating expenses

Other operating expenses decreased by $90,000 in 2009. The decrease in operating expenses was attributable primarily to the cost containment actions, including layoffs and compensation adjustments, implemented by the advanced information services subsidiary in 2009 to reduce costs to offset the decline in revenues. This decrease was offset by the increased merger-related costs.

Other Income

Other income for 2010, 2009 and 2008 was $195,000, $165,000, and $103,000, respectively, which includes interest income, late fees charged to customers and gains or losses from the sale of assets.

Interest Expense

2010 Compared to 2009

Our total interest expense for 2010 increased by approximately $2.1 million, or 29 percent, compared to 2009. The primary drivers of the increased interest expense were related to FPU, including:

- An increase in long-term interest expense of $1.3 million was related to interest on FPU s first mortgage bonds.
- Interest expense from a new term loan credit facility during 2010 was $491,000. In January 2010, we redeemed two series of FPU bonds, the 4.9 percent and 6.85 percent series, to achieve interest savings and to maintain compliance with the covenants in our unsecured senior notes. We used $29.1 million of the new term loan facility for the redemptions.
- Additional interest expense of $730,000 is related to interest on deposits from FPU s customers.

Offsetting the increased interest expense from FPU was lower non-FPU-related interest expense from Chesapeake s unsecured senior notes, as the principal balances decreased from scheduled payments, and lower additional short-term borrowings as a result of the timing of our capital expenditures and reduced working capital requirements, partially due to the increased bonus depreciation in 2010.

2009 Compared to 2008

Total interest expense for 2009 increased by approximately $928,000, or 15 percent, compared to 2008. Total interest expense for 2009 includes approximately $741,000 in FPU s interest expense for the period from the merger closing (October 28, 2009) to December 31, 2009, which was primarily related to $610,000 in interest on FPU s long-term debt and $115,000 in interest on customer deposits. FPU s weighted average interest rate was 7.41 percent for the period from the merger closing to December 31, 2009.

The remaining increase in interest expense in 2009 was attributable to the following factors:

- Excluding FPU s long-term debt, interest expense on long-term debt increased by $990,000 as our average long-term debt balance increased to $92.1 million in 2009 from $76.2 million in 2008. This increase was primarily related to the placement of $30.0 million of 5.93 percent Unsecured Senior Notes in October 2008. The weighted average interest rate on our long-term debt remained fairly constant at 6.37 percent in 2009, compared to 6.40 percent in 2008.
- Interest expense on short-term borrowings decreased by $852,000 in 2009, compared to 2008, as our average short-term borrowing balance decreased to $13.0 million in 2009 from $38.3 million in 2008. The $30.0 million long-term placement in October 2008 contributed to this decrease in addition to a decline in working capital requirements in 2009, due to lower capital expenditures, lower income tax payments from bonus depreciation, net tax operating losses carried forward from 2008 and lower commodity costs. The impact from these factors was offset slightly by increased working capital needs as a result of the FPU merger. Also contributing to the decrease in interest expense in short-term borrowings was a decrease in the weighted average short-term interest rate to 1.28 percent in 2009 from 2.79 percent in 2008 as we continued to experience low interest rates throughout 2009.

Other interest charges increased by $49,000.

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Management s Discussion and Analysis

Income Taxes

2010 Compared to 2009

Income tax expense was $16.9 million in 2010, compared to $10.9 million in 2009, representing an increase of $6.0 million, as a result of increased taxable income in 2010. During 2009, we expensed approximately $871,000 in merger-related costs that we determined to be non-deductible for income tax purposes. Excluding the impact of these costs, our effective income tax rate for 2010 and 2009 remained unchanged at 39.4 percent.

2009 Compared to 2008

Income tax expense was $10.9 million in 2009, compared to $8.8 million in 2008, representing an increase of $2.1 million. During 2009, we expensed approximately $871,000 in merger-related costs that we determined to be non-deductible for income tax purposes. Excluding the impact of these costs, our effective income tax rate for 2009 and 2008 remained primarily unchanged at 39.4 percent and 39.3 percent, respectively. The increase in income tax expense reflects the increased taxable income in 2009.

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

Capital expenditures are one of our largest capital requirements. During 2010, our capital expenditures increased to $47.0 million, from $26.3 million and $30.8 million in 2009 and 2008, respectively, as a result of continued expansions of our natural gas distribution and transmission systems as well as capital expenditures for FPU of $10.9 million and $1.6 million included in our capital expenditures in 2010 and 2009 since the completion of the merger. We have budgeted $51.7 million for capital expenditures during 2011. This amount includes $43.6 million for the regulated energy segment, $3.7 million for the unregulated energy segment and $4.4 million for the Other segment. The amount for the regulated energy segment includes estimated capital expenditures for the following: natural gas distribution operation ($25.4 million), natural gas transmission operation ($12.5 million) and electric distribution operation ($5.7 million) for expansion and improvement of facilities. The amount for the unregulated energy segment includes estimated capital expenditures for the propane distribution operations for customer growth and replacement of equipment. The amount for the Other segment includes estimated capital expenditures of $245,000 for the advanced information services subsidiary with the remaining balance for other general plant, computer software and hardware. We expect to fund the 2011 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.

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Management s Discussion and Analysis

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, 2010 and 2009:

(in thousands)		**December 31, 2010**			**December 31, 2009**	
Long-term debt, net of current maturities	**$**	**89,642**	**28%**	$	98,814	32%
Stockholders equity		**226,239**	**72%**		209,781	68%
Total capitalization, excluding short-term debt	**$**	**315,881**	**100%**	$	308,595	100%

(in thousands)		**December 31, 2010**			**December 31, 2009**	
Short-term debt	**$**	**63,958**	**17%**	$	30,023	8%
Long-term debt, including current maturities		**98,858**	**25%**		134,113	36%
Stockholders equity		**226,239**	**58%**		209,781	56%
Total capitalization, including short-term debt	**$**	**389,055**	**100%**	$	373,917	100%

In consummating the FPU merger, we issued 2,487,910 shares of Chesapeake common stock, valued at approximately $75.7 million, in exchange for all outstanding common stock of FPU. Our balance sheet at the time of the merger also reflected FPU s long-term debt of $47.8 million as a result of the merger.

Since the consummation of the merger, we have redeemed $29.1 million of FPU s long-term debt, which was held in the form of first mortgage bonds. We will be refinancing these redeemed bonds with new Chesapeake unsecured senior notes. We have also entered into an arrangement to refinance an additional $7.0 million of FPU s first mortgage bonds in 2013 with more competitively priced Chesapeake unsecured senior notes. As a result, only $8.0 million of the original $47.8 million of FPU debt as of the merger will be outstanding by 2013 in the form of secured first mortgage bonds.

As of December 31, 2010, 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, 2010, $52.7 million of Chesapeake s cumulative consolidated net income and $28.3 million of FPU s cumulated net income were free of such restrictions.

Management s Discussion and Analysis

Short-term Borrowings

Our outstanding short-term borrowings at December 31, 2010 and 2009 were $64.0 million and $30.0 million, respectively, at the weighted average interest rates of 1.77 percent and 1.28 percent, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to fund temporarily portions of the capital expenditure program. As of December 31, 2010, we had four unsecured bank lines of credit with two financial institutions for a total of $100.0 million. Two of these unsecured bank lines, totaling $60.0 million, are available under committed lines of credit. None of these unsecured bank lines of credit requires compensating balances. Advances offered under the uncommitted lines of credit are subject to the discretion of the banks. We are currently authorized by our Board of Directors to borrow up to $85.0 million of short-term debt, as required, from these unsecured bank lines of credit.

Our outstanding borrowings under these unsecured bank lines of credit at December 31, 2010 and 2009 were $30.8 million and $30.0 million, respectively. During 2010, 2009 and 2008, the average borrowings from these unsecured bank lines of credit were $10.5 million, $13.0 million and $38.3 million, respectively, at weighted average interest rates of 2.40 percent, 1.28 percent and 2.80 percent, respectively. The maximum month-end borrowings from these unsecured bank lines of credit during 2010, 2009 and 2008 were $64.0 million, $33.0 million and $61.2 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, 2010 was $4.1 million representing outstanding checks in excess of funds in deposit, which if presented would be funded through the bank lines of credit.

In addition to the four unsecured bank lines of credit, we entered into a new credit facility for $29.1 million with an existing lender in March 2010. We borrowed $29.1 million under this new credit facility to finance the early redemption of the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds. The interest rate on the borrowing was fixed at 1.88 percent for nine months and on December 16, 2010 the rate was fixed for three months at 1.55 percent. On November 1, 2010 we extended the maturity of this credit facility from March 15, 2011 until October 31, 2011.

On June 29, 2010, we entered into an agreement with an existing senior note holder to issue up to $36 million in uncollateralized senior notes. We expect to use $29 million of the uncollateralized senior notes to permanently finance the early redemption of the 6.85 percent and 4.90 percent series of FPU bonds previously discussed. If refinanced prior to July 8, 2011, these new uncollateralized senior notes will be issued at 5.68 percent and result in annual long-term interest expense of $1.7 million, representing additional interest of $1.2 million, compared to the interest expense of $491,000 on the new short-term loan facility used in 2010. We also expect to use the remaining $7 million to redeem additional FPU secured first mortgage bonds in 2013.

Cash Flows Provided by Operating Activities

Our cash flows provided by operating activities were as follows:

For the Years Ended December 31,	2010	2009	2008
Net income	**$ 26,056**	$ 15,897	$ 13,607
Non-cash adjustments to net income	**37,364**	28,319	22,919
Changes in assets and liabilities	**(2,415)**	1,583	(7,982)
Net cash from operating activities	**$ 61,005**	$ 45,799	$ 28,544

Period-over-period changes in our cash flows from operating activities are attributable primarily to changes in net income, depreciation, deferred 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.

Management s Discussion and Analysis

We 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.

In 2010, our net cash flow provided by operating activities was $61.1 million, an increase of $15.3 million compared to 2009. The increase was due primarily to the following:

Net cash flows from changes in accounts receivable and accounts payable were due primarily to the inclusion of FPU and timing of collections and payments of trading contracts entered into by our propane wholesale and marketing operation;

Net income increased by $10.2 million. A full year s results for FPU and organic growth within Chesapeake s legacy businesses contributed to this increase;

Non-cash adjustments to net income increased by $12.4 million due primarily to higher depreciation and amortization, changes in deferred income taxes, higher employee benefits and compensation and an increase in share based compensation. Higher depreciation and amortization was due to the inclusion of FPU and an increase in capital investments. The increase in deferred income taxes was a result of bonus depreciation in 2010, which significantly reduced our income tax payment obligations in 2010; and

The decrease in income tax receivables was due primarily to the receipt of large refunds in 2009 due to higher tax deductions in 2009 and 2008 and a decrease in taxes payable due to bonus depreciation in 2010.

In 2009, our net cash flow provided by operating activities was $45.8 million, an increase of $17.3 million compared to 2008. The increase was due primarily to the following:

Net cash flows from changes in accounts receivable and accounts payable, due primarily to the timing of collections and payments of trading contracts entered into by our propane wholesale and marketing operation;

Timing of payments for the purchase of propane inventory, natural gas purchases injected into storage, and the relative decline in the unit price of these commodities;

Reduction in regulatory liabilities, which resulted primarily from lower deferred gas cost recoveries in our natural gas distribution operations as the price of natural gas declined in the second half of 2008;

Reduced payments for income taxes payable as a result of higher tax deductions provided by the 2008 Economic Stimulus Act; and

Cash flows provided by non-cash adjustments for deferred income taxes. The increase in deferred income taxes was the result of higher book-to-tax timing differences during the period that were generated by the Economic Stimulus Act, which authorized bonus depreciation for certain assets.

Management s Discussion and Analysis

Cash Flows Used in Investing Activities

In 2010, net cash flows used by investing activities totaled $48.8 million, an increase of $25.7 million compared to 2009. In 2009, net cash flows used by investing activities totaled $23.1 million, a decrease of $8.1 million compared to 2008.

Cash utilized for capital expenditures was $45.4 million, $26.6 million and $30.8 million for 2010, 2009, and 2008, respectively.

We invested $1.6 million in equity securities and paid $1.2 million and $310,000 for the acquisition of Indiantown Gas Company and Virginia LP, respectively, in 2010.

In 2009, we received $3.5 million in proceeds from an investment account related to future environmental costs, as we transferred the amount to our general account that invests in overnight income-producing securities. We also acquired $359,000 in cash, net of cash paid, in the FPU merger in 2009.

Environmental expenditures exceeded amounts recovered through rates charged to customers in 2010, 2009 and 2008 by $290,000, $418,000 and $480,000, respectively.

Cash Flows Provided by/Used in Financing Activities

In 2010 and 2009, net cash flows used by financing activities totaled $13.4 million and $21.4 million, respectively, compared to net cash flows provided by financing activities of $1.7 million in 2008. Significant financing activities included the following:

During 2010 we entered into a new term loan with an existing lender and we borrowed $29.1 million under this facility in order to temporarily finance the early redemption of the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturity.

During 2010 we increased our short-term borrowing by $1.6 million primarily to support our capital expenditures. During 2009 and 2008, we reduced our short-term debt by $3.8 million and $12.0 million, respectively.

We repaid $36.9 million, $10.9 million and $7.7 million of long-term debt during 2010, 2009 and 2008 respectively.

We paid $11.0 million, $8.0 million and $7.8 million in cash dividends in 2010, 2009 and 2008, respectively. An increase in cash dividends paid in each year reflects the growth in the annualized dividend rate. 2010 also reflects dividends on a larger number of shares outstanding, from the FPU shares that were exchanged for Chesapeake shares in the merger.

In October 2008, we completed the placement of $30.0 million of 5.93 percent Unsecured Senior Notes.

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Management s Discussion and Analysis

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2010:

	Payments Due by Period				
Contractual Obligations *(in thousands)*	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
Long-term debt [(1)]	$ 9,216	$ 16,393	$ 21,656	$ 51,682	$ 98,947
Operating leases [(2)]	803	1,234	470	2,017	4,524
Purchase obligations [(3)]					
Transmission capacity	35,051	59,761	37,949	70,293	203,054
Storage Natural Gas	2,615	4,687	1,525	2,063	10,890
Commodities	37,179	100			37,279
Electric supply	1,626	26,498	26,498	39,173	93,795
Forward purchase contracts					
Propane [(4)]	15,618				15,618
Other	144	109			253
Unfunded benefits [(5)]	1,132	731	870	5,706	8,439
Funded benefits [(6)]	2,400	150	108	1,228	3,886
Total Contractual Obligations	**$ 105,784**	**$ 109,663**	**$ 89,076**	**$ 172,162**	**$ 476,685**

(1) Principal payments on long-term debt, see Item 8 under the heading Notes to the Consolidated Financial Statements Note J, Long-Term Debt , for additional discussion of this item. The expected interest payments on long-term debt are $6.6 million, $11.4 million, $8.6 million and $13.3 million, respectively, for the periods indicated above. Expected interest payments for all periods total $40.0 million.

(2) See Item 8 under the heading Notes to the Consolidated Financial Statements Note L, Lease Obligations, for additional discussion of this item.

(3) See Item 8 under the heading Notes to the Consolidated Financial statement Note Q, Other Commitments and Contingencies, in the Notes to the Consolidated Financial Statements for further information.

(4) We have also entered into forward sale contracts. See Market Risk of Management s Discussion and Analysis for further information.

(5) We have recorded long-term liabilities of $8.4 million at December 31, 2010 for unfunded post-employment and post-retirement benefit plans. The amounts specified in the table are based on expected payments to current retirees and assume 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 $16.3 million at December 31, 2010 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 $1.5 million,

reflecting the expected payments the Company will make to the trust funds in 2011. 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 M, Employee Benefit Plans, for further information on the plans. Additionally, the Contractual Obligations table includes deferred compensation obligations totaling $2.4 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

The Board of Directors has authorized the Company $35 million of corporate guarantees on behalf of our subsidiaries and for letters of credit. As of March 2, 2011, the Board increased this limit from $35 million to $45 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily the propane wholesale marketing subsidiary and the natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. None of these subsidiaries has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in the Consolidated Financial Statements when incurred. The aggregate amount guaranteed at December 31, 2010 was $25.6 million, with the guarantees expiring on various dates in 2011.

Management s Discussion and Analysis

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $440,625 which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various insurance outstanding policies. As a result of the recent change in our primary insurance company, we have issued an additional letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2011. There have been no draws on these letters of credit as of December 31, 2010. 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 $2.0 million to TETLP related to the Precedent Agreement with TETLP. The letter of credit is expected to increase quarterly as TETLP s pre-service costs increases. The letter of credit will not exceed the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

(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 their respective PSC; ESNG is subject to regulation by the FERC; and PIPECO is subject to regulation by the Florida PSC. At December 31, 2010, 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 O, 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 P, 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.

(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 (see Item 8 under the heading Notes to the Consolidated Financial Statements Note J, Long-term Debt for annual maturities of consolidated long-term debt). All of our long-term debt is fixed-rate debt and was not entered into for trading purposes. The carrying value of long-term debt, including current maturities, was $98.9 million at December 31, 2010, as compared to a fair value of $113.4 million, based on a discounted cash flow methodology that incorporates a market interest rate that is based on published corporate borrowing rates for debt instruments with similar terms and average maturities with adjustments for duration, optionality, credit risk, and risk profile. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowing, based in part on the fluctuation in interest rates.

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

Our propane wholesale marketing operation is a party to natural gas liquids forward contracts, primarily propane contracts, with various third-parties. These contracts require that the propane wholesale marketing operation purchase or sell natural gas liquids at a fixed price at fixed future dates. At expiration, the contracts are settled by the delivery of natural gas liquids to us or the counterparty or booking out the transaction. Booking out is a procedure for financially settling a contract in lieu of the physical delivery of energy. The propane wholesale marketing operation also enters into futures contracts that are traded on the New York Mercantile Exchange. In certain cases, the futures contracts are settled by the payment or receipt of a net amount equal to the difference between the current market price of the futures contract and the original contract price; however, they may also be settled by physical receipt or delivery of propane.

Management s Discussion and Analysis

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 counterparties, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts. Quantitative information on forward and futures contracts at December 31, 2010 and 2009 is presented in the following tables:

At December 31, 2010	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices	
Forward Contracts				
Sale	13,523,496	$1.0350 $1.4100	$	1.2192
Purchase	12,914,496	$1.0150 $1.3779	$	1.2093
Other Contract				
Put option	1,470,000	$	$	0.1150

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire by the end of the second quarter of 2011.

At December 31, 2009	Quantity in gallons	Estimated Market Prices	Weighted Average Contract Prices	
Forward Contracts				
Sale	11,944,800	$0.6900 $1.3350	$	1.1264
Purchase	11,256,000	$0.7275 $1.3350	$	1.1367
Other Contract				
Put option	1,260,000	$	$	0.1500

Estimated market prices and weighted average contract prices are in dollars per gallon.
All contracts expire in the first quarter of 2010.

At December 31, 2010 and 2009, we marked these forward and other contracts to market, using market transactions in either the listed or OTC markets, which resulted in the following assets and liabilities:

(in thousands)		**December 31, 2010**		December 31, 2009
Mark-to-market energy assets	**$**	**1,642**	$	2,379
Mark-to-market energy liabilities	**$**	**1,492**	$	2,514

Our natural gas distribution, electric distribution and natural gas marketing operations have entered into agreements with natural gas and electricity suppliers to purchase natural gas and electricity 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.

Management s Discussion and Analysis

(i) Competition

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

Our electric distribution operation currently does not face substantial competition as the electric utility industry in Florida has not been deregulated. In addition, natural gas is the only viable alternative fuel to electricity in our electric service territories and is available only in a small area.

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

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

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

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

Management s Discussion and Analysis

(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, Florida filed a declaratory action against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging that FPU breached its obligations under its franchise with the city to provide electric service to customers within and without the city by failing (i) to develop and implement TOU and interruptible rates that were mutually agreed to by the city and FPU; (ii) to have such mutually agreed upon rates in effect by February 17, 2011; and (iii) to have such rates available to all of FPU s customers located within and without the corporate limits of the city. The city is seeking a declaratory judgment to exercise its option under the franchise agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Commission which would also need to approve the presentation of a referendum to voters in the City of Marianna for approval of the purchase and the operation by the city of an electric distribution facility. If the purchase is approved by the Commission and the voters in the City of Marianna, the closing of the purchase must occur within 12 months after the referendum is approved. If the purchase occurs, FPU would have a gain in the year of the disposition. Additionally, future financial results would be negatively impacted from the loss in earnings generated by FPU under the franchise agreement, however such impact is anticipated to be immaterial. FPU intends to file a response to the City s complaint and vigorously contest this litigation and intends to oppose the passage of any proposed referendum that is presented to voters to approve the purchase of the FPU property in the City of Marianna.

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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 Market Risk.

Item 8. Financial Statements and Supplementary Data.

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.

On October 28, 2009, the previously announced merger between Chesapeake and FPU was consummated. FPU s activity is included in Chesapeake s 2010 evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. See Notes to the Consolidated Financial Statements Note B, Acquisitions for additional information relating to the FPU merger.

Chesapeake s management has evaluated and concluded that Chesapeake s internal control over financial reporting was effective as of December 31, 2010.

Report of Independent Registered Public Accounting Firm

To 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, 2010 and 2009, and the related consolidated statements of income, stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, 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, 2010, 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, 2011 expressed an unqualified opinion.

/s/ ParenteBeard LLC

ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2011

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Consolidated Statements of Income

For the Years Ended December 31, *(in thousands, except shares and per share data)*	**2010**	**2009**	**2008**
Operating Revenues			
Regulated Energy	**$ 269,934**	$ 139,099	$ 116,468
Unregulated Energy	**146,793**	119,973	161,290
Other	**10,819**	9,713	13,685
Total operating revenues	**427,546**	268,785	291,443
Operating Expenses			
Regulated energy cost of sales	**144,217**	64,803	54,789
Unregulated energy and other cost of sales	**116,098**	95,467	145,854
Operations	**75,335**	50,706	43,476
Transaction-related costs	**660**	1,478	1,153
Maintenance	**7,484**	3,430	2,215
Depreciation and amortization	**20,758**	11,588	9,005
Other taxes	**11,064**	7,577	6,472
Total operating expenses	**375,616**	235,049	262,964
Operating Income	**51,930**	33,736	28,479
Other income, net of other expenses	**195**	165	103
Interest charges	**9,146**	7,086	6,158
Income Before Income Taxes	**42,979**	26,815	22,424
Income taxes	**16,923**	10,918	8,817
Net Income	**$ 26,056**	$ 15,897	$ 13,607
Weighted Average Common Shares Outstanding:			
Basic	**9,474,554**	7,313,320	6,811,848
Diluted	**9,582,374**	7,440,201	6,927,483
Earnings Per Share of Common Stock:			
Basic	**$ 2.75**	$ 2.17	$ 2.00
Diluted	**$ 2.73**	$ 2.15	$ 1.98
Cash Dividends Declared Per Share of Common Stock	**$ 1.305**	$ 1.250	$ 1.210

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

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Consolidated Statements of Cash Flows

For the Years Ended December 31, *(in thousands)*	**2010**	2009	2008
Operating Activities			
Net Income	**$ 26,056**	$ 15,897	$ 13,607
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	**20,758**	11,588	9,005
Depreciation and accretion included in other costs	**3,133**	2,789	2,239
Deferred income taxes, net	**13,389**	10,065	11,442
Unrealized (gain) loss on commodity contracts	**(116)**	1,606	(1,252)
Unrealized (gain) loss on investments	**(181)**	(212)	509
Employee benefits and compensation	**(757)**	1,217	152
Share based compensation	**1,155**	1,306	820
Other, net	**(17)**	(40)	4
Changes in assets and liabilities:			
Purchase of investments	**(297)**	(146)	(201)
Accounts receivable and accrued revenue	**(20,467)**	(13,652)	19,411
Propane inventory, storage gas and other inventory	**151**	2,597	(1,730)
Regulatory assets	**687**	(1,842)	411
Prepaid expenses and other current assets	**1,157**	(757)	(1,182)
Other deferred charges	**(156)**	(83)	(153)
Long-term receivables	**286**	191	207
Accounts payable and other accrued liabilities	**15,853**	10,185	(15,033)
Income taxes receivable	**(3,761)**	5,020	(6,155)
Accrued interest	**(97)**	66	158
Customer deposits and refunds	**2,038**	(75)	(502)
Accrued compensation	**1,339**	(2,066)	(175)
Regulatory liabilities	**665**	1,071	(3,107)
Other liabilities	**187**	1,074	69
Net cash provided by operating activities	**61,005**	45,799	28,544
Investing Activities			
Property, plant and equipment expenditures	**(45,411)**	(26,603)	(30,756)
Cash acquired in the merger, net of cash paid		359	
(Purchases of) proceeds from investments	**(3,108)**	3,519	
Environmental expenditures	**(290)**	(418)	(480)
Net cash used by investing activities	**(48,809)**	(23,143)	(31,236)
Financing Activities			
Common stock dividends	**(11,013)**	(7,957)	(7,810)
Issuance of stock for Dividend Reinvestment Plan	**568**	392	(118)
Change in cash overdrafts due to outstanding checks	**3,255**	835	(684)
Net borrowing (repayment) under line of credit agreements	**1,579**	(3,812)	(11,980)

Other short-term borrowing	**29,100**		29,961
Repayment of long-term debt	**(36,860)**	(10,907)	(7,658)
Net cash provided by (used in) financing activities	**(13,371)**	(21,449)	1,711
Net Increase (Decrease) in Cash and Cash Equivalents	**(1,175)**	1,207	(981)
Cash and Cash Equivalents Beginning of Period	**2,818**	1,611	2,592
Cash and Cash Equivalents End of Period	**$ 1,643**	$ 2,818	$ 1,611

Supplemental Cash Flow Disclosures (see Note D)

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

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Consolidated Balance Sheets

Assets *(in thousands, except shares and per share data)*	December 31, 2010	December 31, 2009
Property, Plant and Equipment		
Regulated energy	**$ 500,689**	$ 462,061
Unregulated energy	**61,313**	61,334
Other	**16,989**	16,049
Total property, plant and equipment	**578,991**	539,444
Less: Accumulated depreciation and amortization	**(121,628)**	(107,318)
Plus: Construction work in progress	**5,394**	4,461
Net property, plant and equipment	**462,757**	436,587
Investments, at fair value	**4,036**	1,959
Current Assets		
Cash and cash equivalents	**1,643**	2,818
Accounts receivable (less allowance for uncollectible accounts of $1,194 and $1,609, respectively)	**88,074**	69,773
Accrued revenue	**14,978**	12,838
Propane inventory, at average cost	**8,876**	7,901
Other inventory, at average cost	**3,084**	3,149
Regulatory assets	**51**	448
Storage gas prepayments	**5,084**	6,144
Income taxes receivable	**6,748**	2,614
Deferred income taxes	**2,191**	724
Prepaid expenses	**4,613**	5,853
Mark-to-market energy assets	**1,642**	2,379
Other current assets	**245**	147
Total current assets	**137,229**	114,788
Deferred Charges and Other Assets		
Goodwill	**35,613**	34,095
Other intangible assets, net	**3,459**	3,951
Long-term receivables	**155**	440
Regulatory assets	**23,884**	20,100
Other deferred charges	**3,860**	3,891
Total deferred charges and other assets	**66,971**	62,477

Total Assets	**$**	**670,993**	$	615,811

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

Consolidated Balance Sheets

Capitalization and Liabilities *(in thousands, except shares and per share data)*	December 31, 2010	December 31, 2009
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 and 12,000,000 shares, respectively)	**$ 4,635**	$ 4,572
Additional paid-in capital	**148,159**	144,502
Retained earnings	**76,805**	63,231
Accumulated other comprehensive loss	**(3,360)**	(2,524)
Deferred compensation obligation	**777**	739
Treasury stock	**(777)**	(739)
Total stockholders equity	**226,239**	209,781
Long-term debt, net of current maturities	**89,642**	98,814
Total capitalization	**315,881**	308,595
Current Liabilities		
Current portion of long-term debt	**9,216**	35,299
Short-term borrowing	**63,958**	30,023
Accounts payable	**65,541**	51,462
Customer deposits and refunds	**26,317**	25,046
Accrued interest	**1,789**	1,887
Dividends payable	**3,143**	2,959
Accrued compensation	**6,784**	5,341
Regulatory liabilities	**9,009**	8,295
Mark-to-market energy liabilities	**1,492**	2,514
Other accrued liabilities	**10,393**	7,017
Total current liabilities	**197,642**	169,843
Deferred Credits and Other Liabilities		
Deferred income taxes	**80,031**	66,008
Deferred investment tax credits	**243**	335
Regulatory liabilities	**3,734**	4,393
Environmental liabilities	**10,587**	11,104
Other pension and benefit costs	**18,199**	15,088
Accrued asset removal cost Regulatory liability	**35,092**	33,214
Other liabilities	**9,584**	7,231
Total deferred credits and other liabilities	**157,470**	137,373

Other commitments and contingencies (Note P and Q)				
Total Capitalization and Liabilities	**$**	**670,993**	$	615,811

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

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Consolidated Stockholders Equity

(in thousands, except shares and per share data)	Common Stock Number of Shares[7]	Common Stock Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total
Balances at December 31, 2007	**6,777,410**	**$ 3,298**	**$ 65,593**	**$ 51,538**	**$ (852)**	**$ 1,404**	**$ (1,404)**	**$ 119,577**
Net Income				13,607				13,607
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					(71)			(71)
Net loss [5]					(2,825)			(2,825)
Total comprehensive income								10,711
Dividend Reinvestment Plan	9,060	5	269					274
Retirement Savings Plan	5,260	3	156					159
Conversion of debentures	10,397	5	171					176
Share based compensation [1] [3]	24,994	12	442					454
Tax benefit on stock warrants			50					50
Deferred Compensation Plan						145	(145)	
Purchase of treasury stock	(2,425)						(72)	(72)
Sale and distribution of treasury stock	2,425						72	72
Dividends on stock-based compensation				(81)				(81)
Cash dividends [2]				(8,247)				(8,247)
Balances at December 31, 2008	**6,827,121**	**3,323**	**66,681**	**56,817**	**(3,748)**	**1,549**	**(1,549)**	**123,073**
Net Income				15,897				15,897
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					7			7
Net Gain [5]					1,217			1,217
Total comprehensive income								17,121
Dividend Reinvestment Plan	31,607	15	921					936
Retirement Savings Plan	32,375	16	966					982
Conversion of debentures	7,927	4	131					135
Share based compensation [1] [3]	7,374	3	1,332					1,335
Deferred Compensation Plan [6]						(810)	810	
Purchase of treasury stock	(2,411)						(73)	(73)
Sale and distribution of treasury stock	2,411						73	73
Common stock issued in the merger	2,487,910	1,211	74,471					75,682

Dividends on stock-based compensation				(104)				(104)
Cash dividends [2]				(9,379)				(9,379)
Balances at December 31, 2009	**9,394,314**	**4,572**	**144,502**	**63,231**	**(2,524)**	**739**	**(739)**	**209,781**
Net Income				26,056				26,056
Other comprehensive income, net of tax:								
Employee Benefit Plans, net of tax:								
Amortization of prior service costs [4]					8			8
Net loss [5]					(844)			(844)
Total comprehensive income								25,220
Dividend Reinvestment Plan	53,806	26	1,699					1,725
Retirement Savings Plan	27,795	14	889					903
Conversion of debentures	11,865	6	196					202
Tax benefit on share based compensation			253					253
Share based compensation [1] [3]	36,415	17	620					637
Deferred Compensation Plan [6]						38	(38)	
Purchase of treasury stock	1,144						(38)	(38)
Sale and distribution of treasury stock	(1,144)						38	38
Dividends on stock-based compensation				(103)				(103)
Cash dividends [2]				(12,379)				(12,379)
Balances at December 31, 2010	**9,524,195**	**$ 4,635**	**$ 148,159**	**$ 76,805**	**$ (3,360)**	**$ 777**	**$ (777)**	**$ 226,239**

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

(2) Cash dividends declared per share for the periods ended December 31, 2010, 2009 and 2008 were $1.305, $1.250 and $1.210 respectively.

(3) The shares issued under the Performance Incentive Plan (PIP) are net of shares withheld for employee taxes. For 2010 and 2008, the Company withheld 17,695 and 12,511 respectively shares for taxes. The Company did not issue any shares for the PIP in 2009.

(4) Tax expense (benefit) recognized on the prior service cost component of employees benefit plans for the periods ended December 31, 2010, 2009 and 2008 were approximately $5, $5 and ($52) respectively.

(5) Tax expense (benefit) recognized on the net gain (loss) component of employees benefit plans for the periods ended December 31, 2010, 2009 and 2008 were ($541), $794 and ($1,900) respectively.

(6) In May and November 2009, certain participants of the Deferred Compensation Plan received distributions totaling $883. There were no distributions in 2010 and 2008.

(7) Includes 29,600, 28,452, and 62,221 shares at December 31, 2010, 2009 and 2008, respectively, held in a Rabbi Trust established by the Company relating to the Deferred Compensation Plan.

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

Notes to the Consolidated Financial Statements

A. Summary of Accounting Policies

Nature of Business

Chesapeake, incorporated in 1947 in Delaware, is a diversified utility company engaged in regulated energy, unregulated energy and other unregulated businesses. Our regulated energy business delivers natural gas to approximately 120,000 customers located in central and southern Delaware, Maryland s Eastern Shore and Florida and electricity to approximately 31,000 customers in northeast and northwest Florida. Our regulated energy business also provides natural gas transmission service primarily through a 396-mile interstate pipeline from various points in Pennsylvania and northern Delaware to our natural gas distribution affiliates in Delaware and Maryland as well as to other utility and industrial customers in Pennsylvania, Delaware and the Eastern Shore of Maryland.

Our unregulated energy business includes natural gas marketing, propane distribution and propane wholesale marketing operations. The natural gas marketing operation sells natural gas supplies directly to commercial and industrial customers in Florida, Delaware and Maryland. Through our propane distribution operation, we distribute propane to approximately 48,000 customers in Delaware, the Eastern Shore of Maryland and Virginia, southeastern Pennsylvania and Florida. The propane wholesale marketing operation markets propane to wholesale customers including large independent oil and petrochemical companies, resellers and propane distribution companies in the southeastern United States.

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.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Chesapeake and its wholly-owned subsidiaries. As a result of the merger with FPU on October 28, 2009, FPU s financial position, results of operations and cash flows have been consolidated into our results from the effective date of the merger. 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.

System of Accounts

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC with respect to their rates for service, maintenance of their accounting records and various other matters. ESNG is an open access pipeline regulated by the FERC. Our financial statements are prepared in accordance with GAAP, which give appropriate recognition to the ratemaking and accounting practices and policies of the various regulatory commissions. The unregulated energy and other unregulated businesses are not subject to regulation with respect to rates, service or maintenance of accounting records.

Reclassifications

We reclassified certain amounts in the consolidated balance sheet as of December 31, 2009 and in the consolidated statements of cash flows for the years ended December 31, 2009 and 2008 to conform to the current year s presentation. These reclassifications are considered immaterial to the overall presentation of our consolidated financial statements.

Use of Estimates

Our financial statements are prepared in conformity with GAAP, which 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.

Notes to the Consolidated Financial Statements

Property, Plant, Equipment and Depreciation

Property, plant and equipment is stated at original cost less accumulated depreciation or fair value, if impaired. Property, plant and equipment acquired in the merger were stated at fair value at the time of the merger. Costs include direct labor, materials and third-party construction contractor costs, allowance for capitalized interest 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. The provision for depreciation is computed using the straight-line method at rates that amortize the unrecovered cost of depreciable property over the estimated remaining useful life of the asset. Depreciation and amortization expenses for the regulated energy operations are provided at various annual rates, as approved by the regulators.

(in thousands)	**December 31, 2010**	**December 31, 2009**	**Useful Life[1]**
Plant in service			
Mains	**$ 259,672**	$ 236,352	27-62 years
Services utility	**68,349**	65,070	12-48 years
Compressor station equipment	**24,952**	24,981	42 years
Liquified petroleum gas equipment	**27,623**	28,240	5-31 years
Meters and meter installations	**32,850**	28,419	Unregulated energy 3-33 years, regulated energy 14-49 years
Measuring and regulating station equipment	**22,332**	17,708	14-54 years
Office furniture and equipment	**15,796**	15,532	Unregulated energy 4-7 years, regulated energy 14-25 years
Transportation equipment	**17,046**	16,613	1-20 years
Structures and improvements	**16,290**	15,184	3-44 years [2]
Land and land rights	**15,052**	12,789	Not depreciable, except certain regulated assets
Propane bulk plants and tanks	**7,967**	7,275	12-40 years
Electric transmission lines and transformers	**30,669**	29,024	10-41 years
Poles and towers	**9,259**	8,434	21-40 years
Other equipment	**9,189**	11,147	10-61 years
Various	**21,945**	22,676	Various

Total plant in service		**578,991**		539,444
Plus construction work in progress		**5,394**		4,461
Less accumulated depreciation		**(121,628)**		(107,318)
Net property, plant and equipment	**$**	**462,757**	$	436,587

(1) Certain immaterial account balances may fall outside this range.

The regulated operations compute depreciation in accordance with rates approved by either the state PSC or the FERC. These rates are based on depreciation studies and may change periodically upon receiving approval from the appropriate regulatory body. The depreciation rates shown above are based on the remaining useful lives of the assets at the time of the depreciation study, rather than their original lives. The depreciation rates are composite, straight-line rates applied to the average investment for each class of depreciable property and are adjusted for anticipated cost of removal less salvage value.

The non-regulated operations compute depreciation using the straight-line method over the estimated useful life of the asset.

(2) Includes buildings, structures used in connection with natural gas, electric and propane operations, improvements to those facilities and leasehold improvements.

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Notes to the Consolidated Financial Statements

Plant in service includes $1.4 million of assets owned by one of our natural gas transmission subsidiaries, which it uses to provide natural gas transmission service under a contract with a third- party. This contract is accounted for as an operating lease due to exclusive use of the assets by the customer. The service under this contract commenced in January 2009 and provides $264,000 in annual revenues for a term of 20 years. Accumulated depreciation for these assets total $146,000 at December 31, 2010.

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 market value. Investments with an original maturity of three months or less when purchased are considered cash equivalents.

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.

Regulatory Assets, Liabilities and Expenditures

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 to require 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 to our financial position, result of operation and cash flows.

Notes to the Consolidated Financial Statements

At December 31, 2010 and 2009, the regulated utility operations had recorded the following regulatory assets and liabilities on the Balance Sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers rates.

(in thousands)		December 31, 2010		December 31, 2009
Regulatory Assets				
Underrecovered purchased fuel costs	**$**		$	368
Income tax related amounts due from customers		**1,897**		2,022
Deferred post retirement benefits		**8,304**		3,636
Deferred transaction and transition costs		**1,264**		1,486
Deferred conversion and development costs		**2,069**		2,720
Environmental regulatory assets and expenditures		**6,826**		7,510
Acquisition adjustment [1]		**764**		795
Loss on reacquired debt[3]		**1,668**		154
Other		**1,143**		1,857
Total Regulatory Assets	**$**	**23,935**	$	20,548
Regulatory Liabilities				
Self insurance	**$**	**1,265**	$	1,152
Overrecovered purchased fuel costs		**8,159**		6,523
Shared interruptible margins				84
Conservation cost recovery		**320**		1,060
Rate refund[2]				258
Income tax related amounts due to customers		**48**		74
Storm reserve		**2,682**		2,554
Accrued asset removal cost		**35,092**		33,214
Other		**269**		983
Total Regulatory Liabilities	**$**	**47,835**	$	45,902

(1) Net carrying value of goodwill from FPU s previous acquisition that is allowed to be amortized pursuant to a rate order.

(2) Refunded to FPU natural gas customers in February 2010.

(3) Gains and losses resulting from the reacquisition of long-term debt, which are amortized over future periods as adjustments to interest expense in accordance with established regulatory practice.

We have deferred certain costs as regulatory assets prior to obtaining specific regulatory approvals. We have deferred $1.3 million and $1.5 million, of FPU merger-related costs at December 31, 2010 and 2009, respectively, as deferred transaction and transition costs above, which represent our estimate, based on similar proceedings in Florida in the past, of the merger-related costs which we expect to be permitted to recover when we complete the appropriate proceedings. We are currently in the process of discussing this recovery with the Office of Public Counsel. Also included in income tax related amounts due from customers are $1.2 million and $838,000 at December 31, 2010 and

2009, respectively, for which we are currently seeking recovery in the rate case. With the exception of purchased fuel costs and deferred conversion and development costs, there are no material regulatory assets for which we have not earned the appropriate rate of return.

We monitor our regulatory and competitive environment 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.

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Notes to the Consolidated Financial Statements

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 H, Goodwill and Other Intangible Assets, to the Consolidated Financial Statements for additional discussion of this subject.

Other Deferred Charges

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

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 establishing its discount rates, we consider high quality corporate bond rates based on the Moody s Aa bond index, the Citigroup yield curve, changes in those rates from the prior year, and other pertinent factors, such as 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 plan assets component of our annual pension and 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 increase in the discount rate could decrease our pension and postretirement costs by approximately $98,000 and a decrease of 0.25 percent could increase our pension and postretirement costs by $123,000. A 0.25 percent increase in the rate of return would decrease our pension cost by approximately $112,000, and a decrease of 0.25 percent could increase our pension cost by approximately $117,000 and will not have an impact on postretirement and SERP plans because these plans are not funded.

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Notes to the Consolidated Financial Statements

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.

Financial Instruments

Xeron, our propane wholesale marketing operation, 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, net of future servicing costs. The changes in market price are recognized as gains or losses in revenues on the consolidated statements of income in the period of change. There were unrealized gains of $284,000 in 2010 and unrealized losses of $1.6 million in 2009. Trading liabilities are recorded as mark-to-market energy liabilities. Trading assets are recorded as mark-to-market energy assets.

Our natural gas, electric and propane distribution operations and natural gas marketing 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.

The propane distribution operation may enter into a fair value hedge of its inventory in order to mitigate the impact of wholesale price fluctuations. During 2008, we entered into a swap agreement to protect the Company from the impact that propane price increases would have on the Pro-Cap (propane price cap) Plan that the Delmarva propane distribution operation offers to our customers. Propane prices declined significantly in late 2008 and we recorded a mark-to-market loss of approximately $939,000 on the swap agreement in 2008, which increased the cost of propane sales. In January 2009, we terminated the swap agreement. The propane distribution operation may enter into a fair value hedge of its inventory in order to mitigate the impact of wholesale price fluctuations. During 2010 and 2009, we purchased a put option related to the Pro-Cap Plan, which we accounted for on a mark-to-market basis, and recorded a loss of $168,000 and $41,000, respectively. At both December 31, 2010 and 2009, the fair value of the put options was $0.

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Notes to the Consolidated Financial Statements

Earnings Per Share

Basic earnings per share are computed by dividing income available for common shareholders 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 chart.

For the Years Ended December 31,	**2010**	2009	2008
(in thousands, except shares and per share data)			
Calculation of Basic Earnings Per Share:			
Net Income	**$ 26,056**	$ 15,897	$ 13,607
Weighted average shares outstanding	**9,474,554**	7,313,320	6,811,848
Basic Earnings Per Share	**$ 2.75**	$ 2.17	$ 2.00
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income	**$ 26,056**	$ 15,897	$ 13,607
Effect of 8.25% Convertible debentures	**73**	79	89
Adjusted numerator Diluted	**$ 26,129**	$ 15,976	$ 13,696
Reconciliation of Denominator:			
Weighted shares outstanding Basic	**9,474,554**	7,313,320	6,811,848
Effect of dilutive securities:			
Share-based Compensation	**22,550**	34,229	12,083
8.25% Convertible debentures	**85,270**	92,652	103,552
Adjusted denominator Diluted	**9,582,374**	7,440,201	6,927,483
Diluted Earnings Per Share	**$ 2.73**	$ 2.15	$ 1.98

Common stock issued in connection with the FPU merger (See Note B, Acquisitions, to the Consolidated Financial Statements) increased weighted average shares outstanding during 2010 and 2009.

Operating Revenues

Revenues for our natural gas and electric distribution operations are based on rates approved by the PSCs of the states in which they operate. The natural gas transmission operation 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 ESNG 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. In connection with this accrual, we must estimate the amount of natural gas and electricity that have not been accounted for on our delivery systems and must 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.

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Notes to the Consolidated Financial Statements

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 distribution 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 FPU natural gas operation and electric distribution operation in Florida has a purchased 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 purchased fuel costs 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.

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 any of our interruptible customers is 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 and unregulated energy 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.

Depreciation and Accretion Included in Operations Expenses

Depreciation and accretion included in operations expenses consist 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.

Allowance for Doubtful Accounts

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.

Notes to the Consolidated Financial Statements

Acquisition Accounting

The merger with FPU was accounted for under the acquisition method of accounting, with Chesapeake treated as the acquirer. The acquisition method of accounting requires, among other things, that the assets acquired and liabilities assumed in the merger be recognized at their fair value as of the acquisition date. It also establishes that the consideration transferred be measured at the closing date of the merger at the then-current market price. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In addition, market participants are assumed to be buyers and sellers in the principal (or the most advantageous) market for the asset or liability and fair value measures for an asset assume the highest and best use by those market participants, rather than the acquirer s intended use of those assets. In estimating the fair value of the assets and liabilities subject to rate regulation, we considered the nature of the assets and liabilities and the regulatory mechanism for recovery, to which these assets and liabilities are subject, as a factor in determining their appropriate fair value. We also considered the existence of a regulatory process that would allow, or sometimes require, regulatory assets and liabilities to be established for fair value adjustment to certain assets and liabilities subject to rate regulation. If a regulatory asset or liability should be established to offset the fair value adjustment based on the current regulatory process, as was the case for fuel contracts and long-term debt, we did not gross-up our balance sheet to reflect the fair value adjustment and corresponding regulatory asset/liability, because such gross-up would not have resulted in a change to our value of net assets and future earnings.

Total value of the consideration transferred by Chesapeake in the FPU merger was $75.7 million. Net fair value of the assets acquired and liabilities assumed in the FPU merger was estimated to be $41.5 million. This resulted in a purchase premium of $34.2 million, which was reflected as goodwill. Note B, Acquisitions, to the Consolidated Financial Statements describes more fully the purchase price allocation.

Subsequent Events

We have assessed and reported on subsequent events through the date of issuance of these Consolidated Financial Statements.

FASB Statements and Other Authoritative Pronouncements

Recent Accounting Amendments Yet to be Adopted by the Company

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards (IFRS), a comprehensive series of accounting standards published by the International Accounting Standards Board (IASB). Under the proposed roadmap, we may be required to prepare our financial statements in accordance with IFRS as early as 2015. The SEC will make a determination in 2011 regarding the mandatory adoption of IFRS. In July 2009, the IASB issued an exposure draft of Rate-regulated Activities, which sets out the scope, recognition and measurement criteria, and accounting disclosures for assets and liabilities that arise in the context of cost-of-service regulation, to which our rate-regulated businesses are subject. Throughout 2010, IASB has continued its deliberation on the exposure draft and comments received on the overall concept of the recognition of assets and liabilities arising out of cost-of-service regulation. We will continue to monitor the development of the potential implementation of IFRS.

Other Accounting Amendments Adopted by the Company in 2010

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

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

B. Acquisitions

FPU

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

The merger increased our overall presence in Florida by adding approximately 51,000 natural gas distribution customers and 12,000 propane distribution customers to our existing Florida operations. As a result of the merger, we also now serve approximately 31,000 electric customers in northwest and northeast Florida.

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

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

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The following table summarizes the final allocation of the purchase price to the assets acquired and liabilities assumed at the date of the merger.

(in thousands)	October 28, 2009
Purchase price	$ 75,699
Current assets	26,761
Property, plant and equipment	139,709
Regulatory assets	19,899
Investments and other deferred charges	3,659
Intangible assets	4,019
Total assets acquired	194,047
Long term debt	47,812
Borrowings from line of credit	4,249
Other current liabilities	17,427
Pre-merger contingencies	923
Other regulatory liabilities	19,414
Pension and post retirement obligations	14,276
Environmental liabilities	12,414
Deferred income taxes	20,559
Customer deposits and other liabilities	15,467
Total liabilities assumed	152,541
Net identifiable assets acquired	41,506
Goodwill	$ 34,193

During 2010, we adjusted the allocation of the purchase price based on additional information available. The adjustments are related to certain accruals, regulatory assets, deferred and current income tax assets and liabilities, and pre-merger contingencies (see discussion below). These adjustments also resulted in a change in fair value of the propane property, plant and equipment. Goodwill from the merger increased to $34.2 million after incorporating these adjustments, compared to $33.4 million as previously disclosed at December 31, 2009. None of the $34.2 million in goodwill recorded in connection with the merger is deductible for tax purposes. All of the goodwill recorded in connection with the merger is related to the regulated energy segment. We believe the goodwill recognized is attributable to the synergies and opportunities primarily related to FPU s regulated energy businesses. The intangible assets acquired in connection with the merger are related to propane customer list ($3.5 million) and favorable propane supply contracts ($519,000). The intangible value assigned to FPU s existing propane customer list is being amortized over a 12-year period based on the expected duration of the benefit arising from the list. The intangible value assigned to FPU s favorable propane contracts is being amortized over a period ranging from one to 14 months based on contractual terms.

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

The pre-merger contingencies of $923,000 included in the final allocation of the purchase price are primarily related to a pending settlement agreement for a class action complaint against FPU from a propane customer, which is further discussed in Note Q, Other Commitments and Contingencies to the Consolidated Financial Statements. The proposed settlement addresses a particular charge by FPU to its propane customers during the period from May 27, 2006 to September 24, 2010, which encompasses both pre-merger and post-merger periods. We used the ratio of the charges assessed to customers during the pre-merger period to the charges assessed to customers during the total settlement period to estimate that $835,000 of the total contingency was related to FPU s operations prior to the merger with Chesapeake. The portion of the liability related to FPU s operations after the merger with Chesapeake and any increases to the liability after the measurement date, which totaled to $370,000, was expensed in 2010. Also included in the pre-merger contingencies are liabilities related to FPU s income taxes for periods prior to the merger.

Notes to the Consolidated Financial Statements

The financial position and results of operations and cash flows of FPU from the effective date of the merger are included in our consolidated financial statements. The revenue from FPU for the years December 31, 2010 and 2009, included in our consolidated statements of income, were $180.2 million and $26.4 million, respectively, and the net income from FPU for the years ended December 31, 2010 and 2009, included in our consolidated statements of income, were $9.3 million and $1.8 million, respectively.

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

For the Years Ended December 31, *(in thousands, except per share data)*	**2010**	2009
Operating revenues	**$ 427,546**	$ 394,772
Operating Income	**$ 51,930**	$ 44,382
Net Income	**$ 26,056**	$ 20,872
Earnings per share basic	**$ 2.75**	$ 2.23
Earnings per share diluted	**$ 2.73**	$ 2.20

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

The acquisition method of accounting requires acquisition-related costs to be expensed in the period in which those costs are incurred, rather than including them as a component of consideration transferred. It also prohibits an accrual of certain restructuring costs at the time of the merger. As we intend to seek recovery in future rates in Florida of a certain portion of the purchase premium paid and merger-related costs incurred, we also considered the impact of ASC Topic 980, Regulated Operations, in determining the proper accounting treatment for the merger-related costs. As of December 31, 2010, we incurred approximately $3.3 million in costs to consummate the merger, including the cost associated with merger-related litigation and integrating operations following the merger. This includes $369,000 incurred during the year ended December 31, 2010. We deferred approximately $1.3 million of the total costs incurred as a regulatory asset at December 31, 2010, which represents our best estimate, based on similar proceedings in Florida in the past, of the costs which we expect to be permitted to recover when we complete the appropriate rate proceedings.

Included in the $3.3 million merger-related costs incurred as of December 31, 2010, were approximately $452,000 of severance and other restructuring charges for our efforts to integrate the operations of the two companies.

Virginia LP Gas

On February 4, 2010, Sharp Energy, Inc. (Sharp), our propane distribution subsidiary, purchased the operating assets of Virginia LP Gas, Inc., a propane distributor serving approximately 1,000 retail customers in Northampton and Accomack Counties in Virginia. The total consideration for the purchase was $600,000, of which $300,000 was paid at the closing and the remaining $300,000 will be paid over 60 months. Based on our 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 were included in our consolidated statement of income for the year ended December 31, 2010 were not material.

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Indiantown Gas Company

On August 9, 2010, FPU purchased the natural gas operating assets of IGC, which provides natural gas distribution services 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 is deductible for income tax purposes. There was no intangible asset recorded in connection with this acquisition. The revenue and net income from this acquisition which were included in our consolidated statement of income for the year ended December 31, 2010 were not material.

C. 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, electric distribution and natural gas transmission operations. All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of ESNG.
>
> *Unregulated Energy.* The unregulated energy segment includes natural gas marketing, propane distribution and propane wholesale marketing operations, which are unregulated as to their rates and services.
>
> *Other*. The Other segment consists primarily of the advanced information services subsidiary, unregulated subsidiaries that own real estate leased to Chesapeake and certain corporate costs not allocated to other operations.

Notes to the Consolidated Financial Statements

The following table presents information about our reportable segments.

For the Years Ended December 31,	**2010**	**2009**	**2008**
(in thousands)			
Operating Revenues, Unaffiliated Customers			
Regulated Energy	**$ 268,830**	$ 137,847	$ 115,544
Unregulated Energy	**146,430**	119,719	161,287
Other	**12,286**	11,219	14,612
Total operating revenues, unaffiliated customers	**$ 427,546**	$ 268,785	$ 291,443
Intersegment Revenues [1]			
Regulated Energy	**$ 1,104**	$ 1,252	$ 924
Unregulated Energy	**363**	254	3
Other	**856**	779	761
Total intersegment revenues	**$ 2,323**	$ 2,285	$ 1,688
Operating Income			
Regulated Energy	**$ 43,509**	$ 26,900	$ 24,733
Unregulated Energy	**7,908**	8,158	3,781
Other	**513**	(1,322)	(35)
Operating Income	**51,930**	33,736	28,479
Other income	**195**	165	103
Interest charges	**9,146**	7,086	6,158
Income taxes	**16,923**	10,918	8,817
Net income from continuing operations	**$ 26,056**	$ 15,897	$ 13,607
Depreciation and Amortization			
Regulated Energy	**$ 17,038**	$ 8,866	$ 6,694
Unregulated Energy	**3,433**	2,415	2,024
Other and eliminations	**287**	307	287
Total depreciation and amortization	**$ 20,758**	$ 11,588	$ 9,005
Capital Expenditures			
Regulated Energy	**$ 41,898**	$ 22,917	$ 25,386
Unregulated Energy	**2,764**	1,873	3,417
Other	**2,293**	1,504	2,041
Total capital expenditures	**$ 46,955**	$ 26,294	$ 30,844

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

At December 31, *(in thousands)*	**2010**	2009
Identifiable Assets		
Regulated Energy	**$ 520,192**	$ 481,606
Unregulated Energy	**113,039**	99,642
Other	**37,762**	34,286
Total identifiable assets	**$ 670,993**	$ 615,534

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Notes to the Consolidated Financial Statements

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

D. Supplemental Cash Flow Disclosures

Cash paid for interest and income taxes during the years ended December 31, 2010, 2009 and 2008 were as follows:

For the Years Ended December 31,	**2010**	**2009**	**2008**
(in thousands)			
Cash paid for interest	**$ 8,751**	$ 6,703	$ 5,835
Cash paid for income taxes	**$ 10,168**	$ 1,111	$ 3,885

Non-cash investing and financing activities during the years ended December 31, 2010, 2009, and 2008 were as follows:

For the Years Ended December 31,	**2010**	**2009**	**2008**
(in thousands)			
Capital property and equipment acquired on account, but not paid as of December 31	**$ 1,064**	$ 1,151	$ 696
Merger/acquisitions	**$ 300**	$ 75,682	$
Retirement Savings Plan	**$ 902**	$ 982	$ 159
Dividend Reinvestment Plan	**$ 1,182**	$ 692	$ 208
Conversion of Debentures	**$ 202**	$ 135	$ 177
Performance Incentive Plan	**$ 719**	$	$ 568
Director Stock Compensation Plan	**$ 297**	$ 214	$ 181
Tax benefit on stock warrants and share-based compensation	**$ 253**	$	$ 50

E. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas and propane. Our natural gas and propane distribution operations have entered into agreements with suppliers to purchase natural gas and propane for resale to their customers. Purchases under these contracts either do not meet the definition of derivatives or are considered normal purchases and sales and are accounted for on an accrual basis. Our propane distribution operation may also enter into fair value hedges of its inventory in order to mitigate the impact of wholesale price fluctuations. As of December 31, 2010, our natural gas and propane distribution operations did not have any outstanding derivative contracts.

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Xeron, our propane wholesale and marketing operation, engages in trading activities using forward and futures contracts. These contracts are considered derivatives and have been accounted for using the mark-to-market method of accounting. Under the mark-to-market method of accounting, the trading contracts are recorded at fair value and the changes in fair value of those contracts are recognized as unrealized gains or losses in the statement of income in the period of change. As of December 31, 2010, we had the following outstanding trading contracts which we accounted for as derivatives:

At December 31, 2010	Quantity in Gallons	Estimated Market Prices	Weighted Average Contract Prices	
Forward Contracts				
Sale	13,523,496	$1.0350 $1.4100	$	1.2192
Purchase	12,914,496	$1.0150 $1.3779	$	1.2093
Other Contract				
Put option	1,470,000	$	$	0.1150

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

All contracts expire by the end of the second quarter of 2011.

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, 2010 and 2009, are the following:

		Asset Derivatives Fair Value			
(in thousands)	Balance Sheet Location	December 31, 2010		December 31, 2009	
Derivatives not designated as hedging instruments:					
Forward contracts	Mark-to-market energy assets	**$**	**1,642**	$	2,379
Put Option[(1) (2)]	Mark-to-market energy assets				
Total asset derivatives		**$**	**1,642**	$	2,379

		Liability Derivatives Fair Value			
(in thousands)	Balance Sheet Location	December 31, 2010		December 31, 2009	
Derivatives not designated as hedging instruments:					
Forward contracts		**$**	**1,492**	$	2,514

Mark-to-market energy liabilities				
Total liability derivatives	$	**1,492**	$	2,514

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

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

Notes to the Consolidated Financial Statements

The effects of gains and losses from derivative instruments on the Consolidated Statement of Income are the following:

(in thousands)	Location of Gain (Loss) on Derivatives	Amount of Gain (Loss) on Derivatives: For the Years Ended December 31, 2010	2009	2008
Derivatives designated a fair value hedges:				
Propane swap agreement[(1)]	Cost of Sales	**$**	$ (42)	$ 1,476
Derivatives not designated as hedging instruments:				
Put Option[(2)]	Cost of Sales	**(168)**		
Put Option[(3)]	Revenue		(41)	
Unrealized gain (loss) on forward contracts	Revenue	**284**	(1,565)	1,357
Total		**$ 116**	$ (1,648)	$ 2,833

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

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

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

The effects of trading activities on the Consolidated Statements of Income are the following:

(in thousands)	Location of Gain (Loss) on Derivatives	Amount of Trading Revenue For the Years Ended December 31, 2010	2009	2008
Realized gain on forward contracts/put option	Revenue	**$ 1,540**	$ 3,830	$ 1,935
Unrealized gain (loss) on forward contracts	Revenue	**284**	(1,565)	1,357
Total		**$ 1,824**	$ 2,265	$ 3,292

F. 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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Notes to the Consolidated Financial Statements

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2010:

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

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy used at December 31, 2009:

		Fair Value Measurements Using:		
(in thousands)	**Fair Value**	**Quoted Prices in Active Markets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Assets:				
Investments	$ 1,959	$ 1,959		$
Mark-to-market energy assets	$ 2,379	$	$ 2,379	$
Liabilities:				
Mark-to-market energy liabilities	$ 2,514	$	$ 2,514	$

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

Level 1 Fair Value Measurements:

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

Level 2 Fair Value Measurements:

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

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

At December 31, 2010, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

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Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The carrying value of these financial assets and liabilities approximates fair value due to their short maturities and because interest rates approximate current market rates for short-term debt.

At December 31, 2010, long-term debt, which includes the current maturities of long-term debt, had a carrying value of $98.9 million, compared to a fair value of $113.4 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, with adjustments for duration, optionality, and risk profile. At December 31, 2009, the estimated fair value was approximately $145.5 million, compared to a carrying value of $134.1 million.

G. Investments

The investment balance at December 31, 2010, represents: (a) a Rabbi Trust associated with our Supplemental Executive Retirement Savings Plan; (b) a Rabbi Trust related to a stay bonus agreement with a former executive; and (c) investments in equity securities. We classify these investments as trading securities and report them at their fair value. Any unrealized gains and losses, net of other expenses, are included in other income in the consolidated statements of income. We also have an associated liability that is recorded and adjusted each month for the gains and losses incurred by the Rabbi Trusts. At December 31, 2010 and 2009, total investments had a fair value of $4.0 million and $2.0 million, respectively.

H. Goodwill and Other Intangible Assets

The carrying value of goodwill as of December 31, 2010 and 2009 is as follows:

(in thousands)	**December 31, 2010**	December 31, 2009
Regulated Energy	**$ 34,939**	$ 33,421
Unregulated Energy	**674**	674
Total	**$ 35,613**	$ 34,095

Goodwill in the regulated energy segment is comprised of $34.2 million from the FPU merger and $746,000 from the purchase of operating assets from IGC. Goodwill in the unregulated energy segment is comprised of the premium paid by Sharp in its acquisitions in the late 1980s and 1990s.

We test for impairment of goodwill at least annually. The impairment testing for 2010 and 2009 indicated no impairment of goodwill.

Notes to the Consolidated Financial Statements

The carrying value and accumulated amortization of intangible assets subject to amortization as of December 31, 2010 and 2009 are as follows:

	December 31, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
(in thousands)				
Favorable propane contracts	**$ 0**	$ 0	**$ 519**	$ 169
Customer list	**3,500**	340	**3,500**	49
Other	**566**	267	**379**	229
	$ 4,066	$ 607	**$ 4,398**	$ 447

Favorable propane contracts and customer list were acquired in the FPU merger in October 2009. All of the favorable propane contracts expired as of December 31, 2010. The propane customer list is 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 Gas, Inc. in February 2010 and customer lists and acquisition costs from our acquisitions in the late 1980s and 1990s. These intangible assets are amortized over a period ranging from seven to 40 years.

For the years ended December 31, 2010, 2009 and 2008, amortization expense of intangible assets was $679,000, $232,000 and $14,000, respectively. Amortization expense of intangible assets for 2011 to 2015 is: $332,000 for 2011, $329,000 for 2012, $325,000 for 2013 2015.

I. 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 the Company s 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 will continue to file a separate state income tax return in Florida.

In September 2008, the Internal Revenue Service (IRS) completed its examination of our 2005 and 2006 consolidated federal returns and issued its Examination Report. As a result of the examination, we reduced our income tax receivable by $27,000 for the tax liability associated with disallowed expense deductions included on the tax returns. We have amended our 2005 and 2006 federal and state corporate income tax returns to reflect the disallowed expense deductions. We are no longer subject to income tax examinations by the IRS for years before December 31, 2006. FPU filed a separate federal income tax return for the period prior to the merger and is not subject to income tax examinations by the IRS for years before December 31, 2005.

We generated net operating losses in 2008, for federal income tax purposes, primarily from increased book-to-tax timing differences authorized by the 2008 American Recovery and Reinvestment Act, which allowed bonus depreciation for certain assets. A federal tax net operating loss of $9,049,132 was carried forward to 2009 and fully offset taxable income for the year. As of December 31, 2010, we have no remaining carryforward of the 2008 federal tax net operating loss. As of December 31, 2010, we also had tax net operating losses from various states totaling $16.6 million, almost all of which will expire in 2027. We have recorded a deferred tax asset of $1.3 million related to these carry-forwards. We have not recorded a valuation allowance to reduce the future benefit of the tax net operating losses because we believe they will all be utilized.

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The tables below provide the following: (a) the components of income tax expense; (b) reconciliation between the statutory federal income tax rate and the effective income tax rate; and (c) the components of accumulated deferred income tax assets and liabilities at December 31, 2010 and 2009.

For the Years Ended December 31,	**2010**	**2009**	**2008**
(in thousands)			
Current Income Tax Expense			
Federal	**$ 1,566**	$	$ (2,551)
State	**2,116**	878	
Investment tax credit adjustments, net	**(91)**	(69)	(42)
Total current income tax expense (benefit)	**3,591**	809	(2,593)
Deferred Income Tax Expense (1)			
Property, plant and equipment	**16,964**	7,098	10,272
Deferred gas costs	**(2,505)**	(786)	781
Pensions and other employee benefits	**(402)**	(612)	(174)
Amortization of intangibles	**(211)**	5	75
Environmental expenditures	**32**	7	145
Net operating loss carryforwards	**99**	4,106	
Merger related costs	**(13)**	967	
Reserve for insurance deductibles	**(419)**	518	462
Other	**(213)**	(1,194)	(151)
Total deferred income tax expense (benefit)	**13,332**	10,109	11,410
Total Income Tax Expense	**$ 16,923**	$ 10,918	$ 8,817

Reconciliation of Effective Income Tax Rates

	2010	**2009**	**2008**
Continuing Operations			
Federal income tax expense (2)	**$ 15,053**	$ 9,171	$ 7,863
State income taxes, net of federal benefit	**2,083**	1,490	1,162
Merger related costs	**70**	299	
ESOP dividend deduction	**(266)**	(213)	(205)
Other	**(17)**	171	(3)
Total income tax expense	**$ 16,923**	$ 10,918	$ 8,817
Effective income tax rate	**39.38%**	40.72%	39.32%

At December 31,	**2010**	**2009**
(in thousands)		
Deferred Income Taxes		
Deferred income tax liabilities:		

Property, plant and equipment	**$ 89,544**	$ 75,863
Deferred gas costs		848
Loss on reacquired debt	**643**	59
Other	**2,891**	2,884
Total deferred income tax liabilities	**93,078**	79,654
Deferred income tax assets:		
Pension and other employee benefits	**7,849**	7,972
Environmental costs	**1,770**	1,803
Net operating loss carryforwards	**1,300**	305
Self insurance	**419**	464
Storm reserve liability	**1,034**	985
Other	**2,866**	2,841
Total deferred income tax assets	**15,238**	14,370
Deferred Income Taxes Per Consolidated Balance Sheet	**$ 77,840**	$ 65,284

(1) Includes $1,963,000, $1,588,000 and $260,000 of deferred state income taxes for the years 2010, 2009 and 2008, respectively.

(2) Federal income taxes were recorded at 35% for each year represented.

Notes to the Consolidated Financial Statements

J. Long-term Debt

Our outstanding long-term debt is as shown below.

(in thousands)	December 31, 2010	December 31, 2009
FPU secured first mortgage bonds:		
9.57% bond, due May 1, 2018	**$ 7,248**	$ 8,156
10.03% bond, due May 1, 2018	**3,986**	4,486
9.08% bond, due June 1, 2022	**7,950**	7,950
6.85% bond, due October 1, 2031		14,012
4.90% bond, due November 1, 2031		13,222
Uncollateralized senior notes:		
6.91% note, due October 1, 2010		909
6.85% note, due January 1, 2012	**1,000**	2,000
7.83% note, due January 1, 2015	**8,000**	10,000
6.64% note, due October 31, 2017	**19,091**	21,818
5.50% note, due October 12, 2020	**20,000**	20,000
5.93% note, due October 31, 2023	**30,000**	30,000
Convertible debentures:		
8.25% due March 1, 2014	**1,318**	1,520
Promissory note	**265**	40
Total long-term debt	**98,858**	134,113
Less: current maturities	**(9,216)**	(35,299)
Total long-term debt, net of current maturities	**$ 89,642**	$ 98,814

Annual maturities of consolidated long-term debt are as follows: $9,216 for 2011; $8,196 for 2012; $8,196 for 2013; $12,514 for 2014; $9,141 for 2015 and $51,685 thereafter.

Secured First Mortgage Bonds

In October 2009, we became subject to the obligations of FPU s secured first mortgage bonds in connection with the merger. 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.

In January 2010, we redeemed the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturities. The difference between the carrying value of those bonds and the amount paid at redemption totaling $1.5 million was deferred as a regulatory asset. We are amortizing this difference over the remaining terms of these bonds as adjustments to interest expense as allowed by the Florida PSC.

Uncollateralized Senior Notes

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

Notes to the Consolidated Financial Statements

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 2010 and 2009, debentures totaling $202,000 and $135,000, 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 2010 and 2009, no debentures were redeemed for cash. At our option, the debentures may be redeemed at stated amounts.

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 the Company 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, 2010, 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 (such as dividends) 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, 2010, the cumulative consolidated net income base was $128.9 million, offset by Restricted Payments of $76.2 million, leaving $52.7 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, 2010, FPU s cumulative net income base was $65.9 million, offset by restricted payments of $37.6 million, leaving $28.3 million of cumulative net income for FPU free of restrictions pursuant to this covenant. In January 2010, this series of first mortgage bonds was redeemed prior to its maturity.

K. Short-term Borrowing

At December 31, 2010 and 2009, we had $64.0 million and $30.0 million, respectively, of short-term borrowings outstanding. The annual weighted average interest rates on our short-term borrowings were 1.77 percent and 1.28 percent for 2010 and 2009, respectively. We incurred commitment fees of $86,000 and $79,000 in 2010 and 2009, respectively.

The outstanding short-term borrowings at December 31, 2010 were composed of $30.8 million in borrowings from the bank lines of credit, $29.1 million in borrowings from a term loan maturing in March 2011 and $4.1 million in book overdrafts representing outstanding checks in excess of funds on deposit, which if presented would be funded through the bank lines of credit. All of the outstanding short-term borrowings at December 31, 2009 were related to the bank lines of credit.

As of December 31, 2010, we had four unsecured bank lines of credit with two financial institutions, totaling $100.0 million, none of which requires compensating balances. These bank lines are available to provide funds for our short-term cash needs to meet seasonal working capital requirements and to 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 $85.0 million of short-term debt, as required, from these short-term lines of credit.

Notes to the Consolidated Financial Statements

Committed credit facilities

As of December 31, 2010 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, 2010, there were no available funds 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, 2010, there was $29.2 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, 2010, we had two uncommitted lines 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, 2010, 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 $3.2 million in letters of credit under this credit facility. There have been no draws on these letters of credit as of December 31, 2010. 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, 2010, there was $16.8 million available under this credit facility which was reduced by $3.2 million for letters of credit issued.

In addition to the four unsecured bank lines of credit, we entered into a new term loan for $29.1 million with an existing lender in March 2010. We borrowed $29.1 million under this new credit facility related to the early redemption of the 6.85 percent and 4.90 percent series of FPU s secured first mortgage bonds prior to their respective maturities. The interest rate on the borrowing was fixed at 1.88 percent for nine months and on December 16, 2010 the rate was fixed for three months at 1.55 percent. On November 1, 2010 we extended the maturity of this credit facility from March 15, 2011 until October 31, 2011. We are subject to the same covenants representations and warranties for this term loan facility as we are for the $20 million second uncommitted line of credit facility.

In October 2009 in connection with the FPU merger, we became subject to $4.2 million in outstanding borrowings under FPU s revolving line of credit. All of the outstanding borrowings were repaid in full in November 2009 and FPU s revolving line of credit was terminated on November 23, 2009.

Notes to the Consolidated Financial Statements

L. Lease Obligations

We have entered into several operating lease arrangements for office space, equipment and pipeline facilities. Rent expense related to these leases was $1.1 million, $997,000 and $880,000 for 2010, 2009 and 2008, respectively. Future minimum payments under our current lease agreements are $803,000, $717,000, $517,000, $377,000 and $93,000 for the years 2011 through 2015, respectively; and $2.0 million thereafter, with an aggregate total of $4.5 million.

M. 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, 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).

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, 2010:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ (11)	$	$ 83	$	$	$ 72
Net loss	3,221	1,409	793	1,145	531	7,099
Total unrecognized cost	$ 3,210	$ 1,409	$ 876	$ 1,145	$ 531	$ 7,171
Accumulated other comprehesive loss pre-tax[(1)]	$ 3,210	$ 268	$ 876	$ 1,145	$ 101	$ 5,600
Regulatory asset post merger		1,141			430	1,571
Subtotal	3,210	1,409	876	1,145	531	7,171
Regulatory asset pre-merger		6,631			78	6,709
Total	$ 3,210	$ 8,040	$ 876	$ 1,145	$ 609	$ 13,880

(1) The total amount of accumulated other comprehensive loss recorded on our consolidated balance sheets as of December 31, 2010 is net of income tax benefits of $2.2 million.

The pre-merger regulatory asset of $6.7 million at December 31, 2010 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.

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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 2011 are set forth in the following table:

(in thousands)	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
Prior service cost (credit)	$ (5)	$	$ 19	$	$	$ 14
Net (gain) loss	$ 173	$	$ 43	$ 58	$ 22	$ 296
Amortization of pre-merger regulatory asset	$	$ 761	$	$	$ 8	$ 769

In January 2011, our former Chief Executive Officer, John Schimkaitis, retired and received a lump-sum pension distribution of $844,000 from the Chesapeake Pension Plan. He is also expected to receive $765,000 in the form of a lump-sum distribution from the Chesapeake SERP in July 2011. In connection with these lump-sum payment distributions, we expect to record $455,000 in pension settlement losses which will be recorded 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 regulations, Mr. Schimkaitis 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 or 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 the minimum funding requirements of the Employee Retirement Income Security Act of 1974. We were not required to make any funding payments to the Chesapeake Pension Plan in 2009 or to the FPU Pension Plan subsequent to the merger closing in October 2009.

The following schedule summarizes the assets of the Chesapeake Pension Plan, by investment type, at December 31, 2010, 2009 and 2008 and the assets of the FPU Pension Plan, by investment type, at December 31, 2010 and 2009:

	Chesapeake Pension Plan			FPU Pension Plan	
At December 31,	**2010**	**2009**	**2008**	**2010**	**2009**
Asset Category					
Equity securities	**64.33%**	66.22%	48.70%	**60.00%**	63.00%
Debt securities	**30.60%**	33.76%	51.24%	**35.00%**	29.00%
Other	**5.07%**	0.02%	0.06%	**5.00%**	8.00%
Total	**100.00%**	100.00%	100.00%	**100.00%**	100.00%

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The asset listed as Other in the above table represents monies temporarily held in money market funds, which invest at least 80 percent of their total assets in:

- United States government obligations; and
- Repurchase agreements that are fully collateralized by such obligations.

All of the equity securities held by the Chesapeake Pension Plan as of December 31, 2010 and 2009 are classified under Level 1 of the fair value hierarchy and are recorded at fair value based on unadjusted quoted prices in active markets for identical securities. All of the debt securities and other assets held by the Chesapeake Pension Plan as of December 31, 2010 and 2009 are classified under Level 2 of the fair value hierarchy and are recorded at fair value based on quoted market prices in active markets for similar assets or closing prices reported in active markets for those assets. All of the assets held by the FPU Pension Plan as of December 31, 2010 and 2009 are also classified under Level 2 of the fair value hierarchy and are recorded at fair value based on net asset value per unit of those assets.

The investment policy for the Chesapeake Pension Plan calls for an allocation of assets between equity and debt instruments, with equity being 60 percent and debt at 40 percent, but allowing for a variance of 20 percent in either direction. In addition, as changes are made to holdings, cash, money market funds or United States Treasury Bills may be held temporarily by the fund. Investments in the following are prohibited: options, guaranteed investment contracts, real estate, venture capital, private placements, futures, commodities, limited partnerships and Chesapeake stock; short selling and margin transactions are prohibited as well. Investment allocation decisions are made by the Employee Benefits Committee. During 2004, Chesapeake modified its investment policy to allow the Employee Benefits Committee to reallocate investments to better match the expected life of the Chesapeake Pension Plan.

The investment policy for the FPU Pension Plan is designed to achieve a long-term rate of return, including investment income and appreciation, sufficient to meet the actuarial requirements of the plan. The FPU Pension Plan s investment strategy is to achieve its return objectives by investing in a diversified portfolio of equity, fixed income and cash securities seeking a balance of growth and stability as well as an adequate level of liquidity for pension distributions as they fall due. Plan assets are constrained such that no more than 10 percent of the portfolio will be invested in any one issue. Investment allocation decisions for the FPU Pension Plan are also made under the direction of the Employee Benefits Committee.

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The following schedule sets forth the funded status at December 31, 2010 and 2009:

At December 31,	Chesapeake Pension Plan 2010	Chesapeake Pension Plan 2009	FPU Pension Plan 2010	FPU Pension Plan 2009
(in thousands)				
Change in benefit obligation:				
Benefit obligation beginning of year[1]	**$ 11,127**	$ 11,593	**$ 45,420**	$ 46,851
Interest cost	**570**	547	**2,729**	418
Change in assumptions	**(5)**	(188)		
Actuarial loss	**776**	(307)	**6,326**	(1,544)
Benefits paid	**(708)**	(518)	**(1,997)**	(305)
Benefit obligation end of year	**11,760**	11,127	**52,478**	45,420
Change in plan assets:				
Fair value of plan assets beginning of year[1]	**7,449**	6,689	**36,427**	35,037
Actual return on plan assets	**490**	1,278	**4,605**	1,695
Employer contributions	**556**		**1,166**	
Benefits paid	**(708)**	(518)	**(1,997)**	(305)
Fair value of plan assets end of year	**7,787**	7,449	**40,201**	36,427
Reconciliation:				
Funded status	**(3,973)**	(3,678)	**(12,277)**	(8,993)
Accrued pension cost	**$ (3,973)**	$ (3,678)	**$ (12,277)**	$ (8,993)
Assumptions:				
Discount rate	**5.00%**	5.25%	**5.25%**	5.75%
Expected return on plan assets	**6.00%**	6.00%	**7.00%**	7.00%

(1) FPU Pension Plan s beginning balance for 2009 reflects the benefit obligations as of the merger date of October 28, 2009.

Net periodic pension cost (benefit) for the plans for 2010, 2009, and 2008 include the components shown below:

For the Years Ended December 31,	Chesapeake 2010	Chesapeake 2009	Chesapeake 2008	FPU 2010	FPU 2009[1]
(In thousands)					
Components of net periodic pension cost:					
Interest cost	**$ 570**	$ 547	$ 594	**$ 2,729**	$ 418
Expected return on assets	**(423)**	(362)	(629)	**(2,532)**	(396)
Amortization of prior service cost	**(5)**	(5)	(5)		
Amortization of actuarial loss	**155**	237			

Net periodic pension benefit	**$**	**297**	$	417	$	(40)	**$**	**197**	$	22
Assumptions:										
Discount rate		**5.25%**		5.25%		5.50%		**5.75%**		5.50%
Expected return on plan assets		**6.00%**		6.00%		6.00%		**7.00%**		7.00%

(1) FPU s net periodic pension cost is from the merger date (October 28, 2009) through December 31, 2009.

In addition, we recorded $888,000 in expense in 2010 related to continued amortization of FPU s pre-merger pension regulatory asset.

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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 $2.7 million and $2.5 million, at December 31, 2010 and 2009, respectively.

At December 31,	**2010**	**2009**
(in thousands)		
Change in benefit obligation:		
Benefit obligation beginning of year	**$ 2,505**	$ 2,520
Interest cost	**136**	129
Actuarial (gain) loss	**179**	(55)
Amendments		
Benefits paid	**(89)**	(89)
Benefit obligation end of year	**2,731**	2,505
Change in plan assets:		
Fair value of plan assets beginning of year		
Employer contributions	**89**	89
Benefits paid	**(89)**	(89)
Fair value of plan assets end of year		
Reconciliation:		
Funded status	**(2,731)**	(2,505)
Accrued pension cost	**$ (2,731)**	$ (2,505)
Assumptions:		
Discount rate	**5.00%**	5.25%

Net periodic pension costs for the Chesapeake Pension SERP for 2010, 2009, and 2008 include the components shown below:

For the Years Ended December 31,	**2010**	**2009**	**2008**
(in thousands)			
Components of net periodic pension cost:			
Interest cost	**$ 136**	$ 130	$ 125
Amortization of prior service cost	**18**	18	
Amortization of actuarial loss	**59**	54	45
Net periodic pension cost	**$ 213**	$ 202	$ 170
Assumptions:			

Discount rate	**5.25%**	5.25%	5.50%

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Other Postretirement Benefits Plans

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

At December 31,	Chesapeake Postretirement Plan 2010	Chesapeake Postretirement Plan 2009	FPU Medical Plan 2010	FPU Medical Plan 2009
(in thousands)				
Change in benefit obligation:				
Benefit obligation beginning of year[1]	**$ 2,585**	$ 2,179	**$ 2,417**	$ 2,457
Service cost		3	**76**	18
Interest cost	**121**	131	**122**	23
Plan participants contributions	**100**	90		6
Actuarial (gain) loss	**(149)**	378	**595**	(71)
Benefits paid	**(183)**	(196)	**(112)**	(16)
Benefit obligation end of year	**2,474**	2,585	**3,098**	2,417
Change in plan assets:				
Fair value of plan assets beginning of year[1]				
Employer contributions[2]	**83**	106	**112**	10
Plan participants contributions	**100**	90		6
Benefits paid	**(183)**	(196)	**(112)**	(16)
Fair value of plan assets end of year				
Reconciliation:				
Funded status	**(2,474)**	(2,585)	**(3,098)**	(2,417)
Accrued postretirement cost	**$ (2,474)**	$ (2,585)	**$ (3,098)**	$ (2,417)
Assumptions:				
Discount rate	**5.00%**	5.25%	**5.25%**	5.75%

(1) FPU Medical Plan s beginning balance for 2009 reflects the benefit obligation as of the merger date of October 28, 2009.

(2) 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.

Net periodic postretirement benefit costs for 2010, 2009, and 2008 include the following components:

For the Years Ended December 31,	Chesapeake Postretirement Plan 2010	Chesapeake Postretirement Plan 2009	Chesapeake Postretirement Plan 2008	FPU Medical Plan 2010	FPU Medical Plan 2009[1]
(in thousands)					
Components of net periodic postretirement cost:					

Service cost	**$**	$ 3	$ 3	**$ 76**	$ 18
Interest cost	**122**	131	114	**123**	23
Amortization of:					
Actuarial (gain) loss	**57**	76	290	**(6)**	
Net periodic postretirement cost	**$ 179**	$ 210	$ 407	**$ 193**	$ 41
Assumptions					
Discount rate	**5.25%**	5.25%	5.50%	**5.75%**	5.50%

(1) FPU Medical Plan s net periodic cost includes only the cost from the merger date (October 28, 2009) through December 31, 2009.

Notes to the Consolidated Financial Statements

In addition, we recorded $9,000 in expense 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 2010, 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 lives of the plan and investment policies, particularly in light of the lump-sum-payment option provided in the Chesapeake Pension Plan, different discount rate and expected return on plan asset assumptions were selected for Chesapeake s plans and FPU s plans. Since all of the 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 2010 used to calculate the benefit obligation is seven percent for medical and eight percent for prescription drugs for the Chesapeake Postretirement Plan; and 10.50 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 $787,000 as of January 1, 2010, and would increase the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2010 by approximately $48,000. A one-percentage point decrease in the health care inflation rate from the assumed rate would decrease the accumulated postretirement benefit obligation by approximately $582,000 as of January 1, 2010, and would decrease the aggregate of the service cost and interest cost components of the net periodic postretirement benefit cost for 2010 by approximately $40,000.

Estimated Future Benefit Payments

In 2011, we expect to contribute $205,000 and $1.3 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, and $853,000 to the Chesapeake SERP. We also expect to contribute $96,000 and $158,000 to the Chesapeake Postretirement Plan and FPU Medical Plan, respectively, in 2011. The schedule below shows the estimated future benefit payments for each of the plans previously described:

(in thousands)	Chesapeake Pension Plan(1)	FPU Pension Plan(1)	Chesapeake SERP(2)	Chesapeake Postretirement Plan(2)	FPU Medical Plan(2)(3)
2011	$ 1,315	$ 2,324	$ 853	$ 96	$ 158
2012	$ 465	$ 2,484	$ 87	$ 104	$ 151
2013	$ 533	$ 2,662	$ 86	$ 111	$ 144
2014	$ 556	$ 2,815	$ 84	$ 119	$ 169
2015	$ 686	$ 2,939	$ 133	$ 128	$ 189
Years 2016 through 2020	$ 3,932	$ 15,974	$ 672	$ 703	$ 1,040

(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.

(3) These amounts are shown net of estimated Medicare Part-D reimbursements of $9,000, $10,000, $11,000, $12,000 and $13,000 for the years 2011 to 2015, respectively, and $78,000 for the years 2015 through 2019.

Notes to the Consolidated Financial Statements

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

We sponsor two 401(k) retirement savings plans and one non-qualified supplemental employee retirement savings plan.

Chesapeake s 401(k) plan is offered to all eligible employees, except for those FPU employees, who have the opportunity to participate in FPU s 401(k) plan. 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 the eligible compensation, including pre-tax contributions made by BravePoint employees. In addition, we may make a supplemental contribution to all 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 will be 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 participants, employees are 100 percent vested after two years of service or have attained an age of 55 years 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.

Prior to January 1, 2011, we made matching contributions on up to six percent of each Chesapeake employee s eligible pre-tax compensation for the year, except for the employees of our advanced information services subsidiary, as further explained below. The match was between 100 percent and 200 percent of the employee s contribution (up to six percent), 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 option 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 the advanced information services subsidiary 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.

We continue to maintain a separate 401(k) retirement savings plan for FPU. Effective January 1, 2011, we match 100 percent of eligible non-union participants pre-tax contributions to the FPU 401(k) plan up to a maximum of six percent of the eligible compensation. Eligible employees who have not opted out of the plan are automatically enrolled at the three-percent deferral rate and the automatic deferral will increase by one percent per year up to a maximum of six percent, unless an employee elects otherwise, with vesting of 100 percent after two years of service. Employees with one year of service are 20 percent vested and become 100 percent vested after two years of service. Also, we may make other supplemental employer contributions to the plan at such time that we deem appropriate. Supplemental employer contributions may be made to the eligible plan participants based on the employee compensation for the year. Participants are only eligible for the employer and supplemental employer contributions if they have worked for at least 501 hours and 1000 hours respectively during the Plan Year.

Notes to the Consolidated Financial Statements

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, with the option 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.

Effective January 1, 1999, we began offering a non-qualified supplemental employee retirement savings plan (401(k) SERP) to our executives 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. These same funds are available for investment of employee contributions within Chesapeake s 401(k) plan. 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. As discussed further in Note G Investments, to the Consolidated Financial Statements, the assets held in the Rabbi Trust included a fair value of $2.4 million and $2.0 million at December 31, 2010 and 2009, respectively, related to the 401(k) SERP. The assets of the Rabbi Trust are at all times subject to the claims of our general creditors.

Contributions to all of our 401(k) plans totaled $1.7 million for the year ended December 31, 2010 and $1.6 million for both years ended December 31, 2009 and 2008. As of December 31, 2010, there are 582,486 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, 2010, 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 and directors stock retainers are paid in shares of our common stock, except that cash is paid in lieu of fractional shares.

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 $777,000 and $739,000 at December 31, 2010 and 2009, respectively.

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N. Share-Based Compensation Plans

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

The table below presents the amounts included in net income related to share-based compensation expense, for the restricted stock awards issued under the DSCP and the PIP for the years ended December 31, 2010, 2009 and 2008:

For the Years Ended December 31,		**2010**		**2009**		**2008**
(in thousands)						
Directors Stock Compensation Plan	**$**	**283**	$	191	$	180
Performance Incentive Plan		**872**		1,115		640
Total compensation expense		**1,155**		1,306		820
Less: tax benefit		**463**		523		327
Share-Based Compensation amounts included in net income	**$**	**692**	$	783	$	493

Stock Options

We did not have any stock options outstanding at December 31, 2010 or 2009, nor were any stock options issued during 2010, 2009 and 2008.

Directors Stock Compensation Plan

Under the DSCP, each of our non-employee directors received in 2010 an annual retainer of 900 shares of common stock. Shares granted under the DSCP are issued in advance of the directors service period; therefore, these shares are fully vested as of the grant date. We record a prepaid expense as of the date of the grant equal to the fair value of the shares issued and amortize the expense equally over a service period of one year.

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

	Number of Shares		**Weighted Average Grant Date Fair Value**
Outstanding December 31, 2008			
Granted (1)	7,174	$	29.83
Vested	7,174	$	29.83
Forfeited			
Outstanding December 31, 2009			
Granted	9,900	$	29.99
Vested	9,900	$	29.99
Forfeited			
Outstanding December 31, 2010			

(1)

On October 28, 2009, we added two new members to our Board of Directors; each new member was awarded 337 shares of common stock for the prorated portion of their service period.

We recorded compensation expense of $283,000, $191,000 and $180,000 related to DSCP awards for the years ended December 31, 2010, 2009 and 2008, respectively.

Notes to the Consolidated Financial Statements

The weighted average grant-date fair value of DSCP awards granted during 2010 and 2009 was $29.99 and $29.83, 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, 2010, there was $99,000 of unrecognized compensation expense related to DSCP awards that is expected to be recognized over the first four months of 2011.

As of December 31, 2010, there were 34,215 shares reserved for issuance under the DSCP.

Performance Incentive Plan (PIP)

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.

In 2007, the Board of Directors granted each executive officer equity incentive awards, which entitled each to earn shares of common stock to the extent that we achieved pre-established performance goals at the end of a one-year performance period. In 2008, we adopted multi-year performance plans to be used in lieu of the one-year awards. Similar to the one-year plans, the multi-year plans provide incentives based upon the successful achievement of long-term goals, growth, and financial results and they are comprised of both market-based and performance-based conditions or targets.

A portion of the shares granted under the PIP in 2008 vested in 2010, and the fair value of each share is equal to the market price of our common stock on the date of the grant. The shares granted under the 2009 and 2010 long-term plans have not vested as of December 31, 2010, and the fair value of each performance-based condition or target is equal to the market price of our common stock on the date of the grant. For the market-based conditions, we used the Black-Scholes pricing model to estimate the fair value of each market-based award granted.

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

	Number of Shares		Weighted Average Fair Value
Outstanding December 31, 2008	94,200	$	27.84
Granted	28,875	$	29.19
Vested			
Fortfeited			
Expired			
Outstanding December 31, 2009	123,075	$	28.15
Granted	40,875		29.38
Vested	43,960		27.94
Fortfeited			
Expired	18,840		27.94
Outstanding December 31, 2010	101,150	$	28.78

In 2010 and 2008 (in 2009, no shares under the PIP vested), 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 17,695 and 12,511 for 2010 and 2008, 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. No payments for the employee s tax obligations were made to taxing authorities in 2009 as no shares vested during this period. Total payments for the employees tax obligations to the taxing authorities were approximately $538,000 and $383,000 in 2010 and 2008, respectively.

Notes to the Consolidated Financial Statements

We recorded compensation expense of $872,000, $1.1 million and $640,000 related to the PIP for the years ended December 31, 2010, 2009, and 2008, respectively.

The weighted average grant-date fair value of PIP awards granted during 2010, 2009 and 2008 was $29.38, $29.19 and $27.84, per share, respectively. The intrinsic value of the PIP awards was $2.7 million, $2.1 million and $1.1 million for 2010, 2009 and 2008, respectively.

As of December 31, 2010, there were 345,028 shares reserved for issuance under the PIP.

O. 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; ESNG, our natural gas transmission subsidiary, is subject to regulation by the FERC; and PIPECO, 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

On September 2, 2008, our Delaware division filed with the Delaware PSC its annual Gas Sales Service Rates (GSR) Application, seeking approval to change its GSR, effective November 1, 2008. On July 7, 2009, the Delaware PSC granted approval of a settlement agreement presented by the parties in this docket, which included the Delaware PSC, our Delaware division and the Division of the Public Advocate. As part of the settlement, the parties agreed to develop a record in a later proceeding on the price charged by the Delaware division for the temporary release of transmission pipeline capacity to our natural gas marketing subsidiary, PESCO. On January 8, 2010, the Hearing Examiner in this proceeding issued a report of Findings and Recommendations in which he recommended, among other things, that the Delaware PSC require the Delaware division to refund to its firm service customers the difference between what the Delaware division would have received had the capacity released to PESCO been priced at the maximum tariff rates under asymmetrical pricing principles and the amount actually received by the Delaware division for capacity released to PESCO. The Hearing Examiner also recommended that the Delaware PSC require us to adhere to asymmetrical pricing principles in all future capacity releases by the Delaware division to PESCO, if any. Accordingly, if the Hearing Examiner s refund recommendation for past capacity releases were approved without modification by the Delaware PSC, the Delaware division would have to credit to its firm service customers amounts equal to the maximum tariff rates that the Delaware division pays for long-term capacity, which we estimated to be approximately $700,000, even though the temporary releases were made at lower rates based on competitive bidding procedures required by the FERC s capacity release rules. We disagreed with the Hearing Examiner s recommendations and filed exceptions to those recommendations on February 18, 2010.

At the hearing on March 30, 2010, the Delaware PSC agreed with us that the Delaware division had been releasing capacity based on a previous settlement approved by the Delaware PSC and, therefore, did not require the Delaware division to issue any refunds for past capacity releases. The Delaware PSC, however, required the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO until a more appropriate pricing methodology is developed and approved. The Delaware PSC issued an order on May 18, 2010 elaborating its decisions at the March hearing and directing the parties to reconvene in a separate docket to determine if a pricing methodology other than asymmetrical pricing principles should apply to future capacity releases by the Delaware division to PESCO. On June 17, 2010, the Division of the Public Advocate filed an appeal with the Delaware Superior Court, asking it to overturn the Delaware PSC s decision with regard to refunds for past capacity releases. On June 28, 2010, the Delaware division filed a Notice of Cross Appeal with the Delaware Superior Court asking it to overturn the Delaware PSC s decision with regard to requiring the Delaware division to adhere to asymmetrical pricing principles for future capacity releases to PESCO. The parties involved filed opening briefs with the Delaware Superior Court on September 30, 2010, answering briefs on October 20, 2010, and reply briefs on November 3, 2010. We anticipate that the Court will render a decision sometime in 2011. Due to the ongoing legal proceeding, the parties have not yet opened a separate docket to determine an alternative pricing methodology for future capacity releases. We did not accrue any contingent liability related to potential refunds for past capacity releases. Since the Delaware PSC s Order on May 18, 2010, the Delaware division has not released any capacity to PESCO.

Notes to the Consolidated Financial Statements

On September 4, 2009, the Delaware division filed with the Delaware PSC its annual GSR Application, seeking approval to change its GSR, effective November 1, 2009. On October 6, 2009, the Delaware PSC authorized the Delaware division to implement the GSR charges on November 1, 2009, on a temporary basis, subject to refund, pending the completion of full evidentiary hearings and a final decision. The evidentiary hearing in this matter was held on May 19, 2010. At the evidentiary hearing, the parties in this docket, which included the Delaware PSC, the Delaware division and the Division of the Public Advocate, presented a proposed settlement agreement to resolve all issues addressed in this docket. The settlement agreement contemplates that the Delaware division will begin to share interruptible margins with its firm ratepayers when those margins reach a certain level in each 12-month period ending October 31. Based on the current level of interruptible margins generated by the Delaware division, we do not anticipate that sharing of future interruptible margins will have a significant impact on our results. The Delaware PSC approved the settlement agreement on September 7, 2010.

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

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

Maryland

On December 1, 2009, 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, 2009. No issues were raised at the hearing, and on December 9, 2009, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. On January 8, 2010, the Maryland PSC issued an Order substantially affirming the Hearing Examiner s decision in the matter.

On December 14, 2010, 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, 2010. No issues were raised at the hearing, and on December 20, 2010, the Hearing Examiner in this proceeding issued a proposed Order approving the division s four quarterly filings. This proposed Order became a final Order of the Maryland PSC on January 20, 2011.

Florida

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

Notes to the Consolidated Financial Statements

Also on December 15, 2009, the Florida PSC approved the settlement agreement for a final natural gas rate increase of $7,969,000 for FPU s natural gas distribution operation. The Florida PSC had approved an annual interim rate increase of $984,054 on February 10, 2009 and approved the permanent rate increase of $8,496,230 in an order issued on May 5, 2009, with the new rates to be effective beginning on June 4, 2009. On June 17, 2009, however, the Office of Public Counsel entered a protest to the Florida PSC s order and its final natural gas rate increase ruling. Subsequent negotiations led to the settlement agreement between the Office of Public Counsel and FPU, which the Florida PSC approved on December 15, 2009. The rates authorized pursuant to the order approving the settlement agreement became effective on January 14, 2010. In February 2010, FPU refunded to its natural gas customers approximately $290,000, representing revenues in excess of the amount provided by the settlement agreement that had been billed to customers from June 2009 through January 14, 2010.

In 2010, we recorded a $750,000 accrual related to the regulatory risk for FPU s natural gas distribution operation associated with its earnings, merger benefits and recovery of the purchase premium.. We are required to detail known benefits, synergies, cost savings and cost increases resulting from the merger and present the information in the come-back filing to the Florida PSC by April 29, 2011 (within 18 months of the merger). We are currently in discussions with the Office of Public Counsel and the Florida PSC staff regarding the benefits and cost savings of the merger, current and expected earnings levels as well as the recovery of approximately $34.9 million in purchase premium and $2.2 million in merger-related costs. We recorded this accrual based on our assessment of FPU s current earnings, the regulatory environment in Florida and progress of the current discussions.

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

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

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

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

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

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

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

On, July 7, 2009, the City of Marianna, Florida Commission (the Commission) passed an ordinance granting a franchise to FPU effective February 1, 2010 for a period not to exceed 10 years for the operation and distribution and/or sale of electric energy (the franchise agreement). The franchise agreement provides that FPU will develop and implement new time-of-use (TOU) and interruptible electric power rates that shall be mutually agreed upon by FPU and the city. The franchise agreement further provides that the TOU and interruptible rates be effective no later than February 17, 2011 and available to all customers within the corporate limits of the City of Marianna. If the rates are not in effect by February 17, 2011, the city has the right to give notice to FPU within 180 days thereafter of its intent to exercise its option to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Commission which would also need to approve the presentation of a referendum to voters in the City of Marianna for the approval of the purchase and the operation by the city of an electric distribution facility. If the purchase is approved by the Commission and the voters in the City of Marianna, the closing of the purchase must occur within 12 months after the referendum is approved. If the city elects to purchase the Marianna property, the agreement requires the city to pay FPU the fair market value for such property as determined by three qualified appraisers.

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

As disclosed in Note Q, Other Commitments and Contingencies, on March 2, 2011, the city filed a declaratory action against FPU in the Circuit Court of the Fourteenth Judicial Circuit in and for Jackson County, Florida, alleging breaches of the franchise agreement by FPU and seeking a declaratory judgment that the city has the right to exercise its option to purchase FPU s property in the City of Marianna in accordance with the terms of the franchise agreement.

Notes to the Consolidated Financial Statements

ESNG

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

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

Mainline Extension Project: On November 25, 2009, ESNG filed a notice of its intent under its blanket certificate to construct, own and operate new mainline facilities to deliver additional firm service of 1,594 Mcfs per day of natural gas to Chesapeake s Delaware division. The FERC published the notice of this filing on December 7, 2009. No protest was filed during the 60-day period following the notice, and ESNG commenced construction on February 6, 2010. The facilities were completed on April 29, 2010, and ESNG commenced billing for the new service on May 1, 2010.

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

Rate Case Filing: On December 30, 2010, ESNG filed a base rate proceeding in compliance with the terms of the settlement in its prior rate base proceeding. ESNG s filed rates, proposed to be effective February 1, 2011, reflect an annual increase of $6,748,628 over its current rates. The proposed rate increase reflects increases in operating and maintenance expenses, depreciation expense, and return on new gas plant facilities that are expected to be placed into service before June 30, 2011. ESNG proposed a return on equity of 13.5 percent. ESNG expects to reach a settlement agreement on the filing in 2011.

ESNG also had developments in the following FERC matters:

On April 30, 2010, ESNG submitted its annual Interruptible Revenue Sharing Report to the FERC. ESNG reported in this filing that its interruptible revenue was in excess of its annual threshold amount and refunded $90,718, inclusive of interest, in the second quarter of 2010 to its eligible firm customers.

On May 28, 2010, ESNG submitted its annual Fuel Retention Percentage (FRP) and Cash-Out Surcharge filings to the FERC. In these filings, ESNG proposed to implement a FRP rate of 0.00 percent and a zero rate for its Cash-Out Surcharge. ESNG also proposed to refund $310,117, inclusive of interest, to its eligible customers in the second quarter of 2010 as a result of combining its over-recovered Gas Required for Operations and its over-recovered Cash-Out Cost. The FERC approved these proposals on June 29, 2010, and ESNG issued refunds to eligible customers.

Notes to the Consolidated Financial Statements

On August 16, 2010, ESNG submitted its compliance filing with regard to the FERC s Order on Electronic Tariff Filings (Order No. 714). This Order required all natural gas pipelines subject to FERC jurisdiction to file baseline tariff sheets electronically. All subsequent rate and tariff-related filings are to be made electronically. On October 13, 2010, the FERC approved ESNG s compliance filing for this Order.

On September 1, 2010, ESNG submitted its compliance filing with regard to the FERC s most recent Order adopting Standards for Business Practices for Interstate Natural Gas Pipelines (Order No. 587-U). With this Order, FERC incorporated by reference into its regulations Version 1.9 of the North American Energy Standards Board Wholesale Gas Quadrant s standards. On October 13, 2010, FERC approved ESNG s compliance filing.

P. Environmental Commitments and Contingencies

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

We have participated in the investigation, assessment or remediation and have certain exposures at six former 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. The Key West, Pensacola, Sanford and West Palm Beach sites are related to FPU, for which we assumed in the merger any existing and future contingencies.

As of December 31, 2010, we had $358,000 in environmental liabilities related to Chesapeake s MGP sites in Maryland and Florida, representing our estimate of the future costs associated with those sites. As of December 31, 2010, we had approximately $1.3 million in regulatory and other assets for future recovery of environmental costs from Chesapeake s customers through our approved rates. As of December 31, 2010, we had approximately $11.6 million in environmental liabilities related to FPU s MGP sites in Florida, primarily from the West Palm Beach site, which represents our estimate of the future costs associated with those sites. FPU has approval to recover up to $14.0 million of its environmental costs from insurance and from customers through rates. Approximately $7.8 million of FPU s expected environmental costs have been recovered from insurance and customers through rates as of December 31, 2010. We also had approximately $6.2 million in regulatory assets for future recovery of environmental costs from FPU s customers.

The following discussion provides details on each site.

Salisbury, Maryland

We have substantially completed remediation of this site in Salisbury, Maryland, where it was determined that a former MGP caused localized ground-water contamination. During 1996, we completed construction of an Air Sparging and Soil-Vapor Extraction (AS/SVE) system and began remediation procedures. We have reported the remediation and monitoring results to the MDE on an ongoing basis since 1996. In February 2002, the MDE granted permission to permanently decommission the AS/SVE system and to discontinue all on-site and off-site well monitoring, except for one well, which is being maintained for periodic product monitoring and recovery. We have requested and are awaiting a No Further Action determination from the MDE.

Notes to the Consolidated Financial Statements

Through December 31, 2010, we have incurred and paid approximately $2.9 million for remedial actions and environmental studies. We have recovered approximately $2.2 million through insurance proceeds or in rates and have $667,000 to be recovered through future rates.

Winter Haven, Florida

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

The BS/SVE treatment system does not address impacted soils in the southwest corner of the site. On April 16, 2010, a soil excavation interim RAP describing the proposed excavation of approximately 4,000 cubic yards of impacted soils from the southwest corner of the site was submitted to the FDEP for review. The FDEP provided comments to the soil excavation interim RAP by letter, dated June 24, 2010. A response letter, dated August 3, 2010, was submitted to FDEP. A subsequent conditional approval letter, dated August 27, 2010, was issued by FDEP. The cost to implement this excavation plan has been estimated at $250,000; however, this estimate does not include costs associated with dewatering or shoreline stabilization, which would be required to complete the excavation. Because the costs associated with shoreline stabilization and dewatering (including treatment and discharge of the pumped water) are likely substantial, alternatives to this excavation plan will to be evaluated. We plan to perform the excavation in late 2011 or early 2012.

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

Through December 31, 2010, we have incurred and paid approximately $1.6 million for this site and estimate an additional cost of $358,000 in the future, which has been accrued. We have recovered through rates $1.3 million of the costs and continue to expect that the remaining $658,000, which is included in regulatory assets, will be recoverable from customers through our approved rates.

Key West, Florida

FPU formerly owned and operated an MGP in Key West, Florida. Field investigations performed in the 1990s identified limited environmental impacts at the site, which is currently owned by an unrelated third party, Suburban Propane. In September 2010, FDEP issued a Preliminary Contamination Assessment Report, for additional soil and groundwater investigation work that was undertaken by FDEP in November 2009 and January 2010, after 17 years of regulatory inactivity. Because FDEP observed that some soil and groundwater standards were exceeded, FDEP is seeking to meet with FPU and the current site owner, Suburban Propane, to discuss additional field work which the FDEP believes is warranted for the site. Potential costs for investigation and remediation are projected to be $153,000.

Notes to the Consolidated Financial Statements

Pensacola, Florida

FPU formerly owned and operated an MGP in Pensacola, Florida. The MGP was also owned by Gulf Power. Portions of the site are now owned by the city of Pensacola and the Florida Department of Transportation (FDOT). In October 2009, FDEP informed Gulf Power that FDEP would approve a conditional No Further Action (NFA) determination for the site, which must include a requirement for institutional and engineering controls. On November 9, 2010, an NFA Proposal was submitted to FDEP, along with a draft restrictive covenant for the property currently owned by FDOT. At this point, it is anticipated that no further monitoring will be required on the site. The remaining consulting and remediation costs are projected to be $7,000.

Sanford, Florida

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

In January 2007, FPU and other members of the Sanford Group signed a Third Participation Agreement, which provides for funding the final remedy approved by EPA for the site. FPU s share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13 million, or $650,000. As of December 31, 2010, FPU has paid $650,000 to the Sanford Group escrow account for its share of funding requirements.

The Sanford Group, EPA and the U.S. Department of Justice agreed to a Consent Decree in March 2008, which was entered by the federal court in Orlando, Florida on January 15, 2009. The Consent Decree obligates the Sanford Group to implement the remedy approved by EPA for the site. The total cost of the final remedy is now estimated at approximately $18 million. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed by FPU in the Third Participation Agreement.

Several members of the Sanford Group have concluded negotiations with two adjacent property owners to resolve damages that the property owners allege they have and will incur as a result of the implementation of the EPA-approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims.

As of December 31, 2010, FPU s remaining share of remediation expenses, including attorneys fees and costs, is estimated to be $20,000. However, we are unable to determine, to a reasonable degree of certainty, whether the other members of the Sanford Group will accept FPU s asserted defense to liability for costs exceeding $13 million to implement the final remedy for this site or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid under the Third Participation Agreement.

Notes to the Consolidated Financial Statements

West Palm Beach, Florida

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

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

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

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

Other

We are in discussions with the MDE regarding a former MGP site located in Cambridge, Maryland. The outcome of this matter cannot be determined at this time; therefore, we have not recorded an environmental liability for this location.

Q. Other Commitments and Contingencies

Litigation

In May 2010, a FPU propane customer filed a class action complaint against FPU in Palm Beach County, Florida, alleging, among other things, that FPU acted in a deceptive and unfair manner related to a particular charge by FPU on its bills to propane customers and the description of such charge. The suit sought to certify a class comprised of FPU propane customers to whom such charge was assessed since May 2006 and requested damages and statutory remedies based on the amounts paid by FPU customers for such charge. FPU vigorously denies any wrongdoing and maintains that the particular charge at issue is customary, proper and fair. Without any admission by FPU of any wrongdoing, validity of the claims or a properly certifiable class for the complaint, FPU entered into a settlement agreement with the plaintiff in September 2010 to avoid the burden and expenses of continued litigation. The court approved the final settlement. The judgement becomes final when the time for appeal expires, which is expected on March 13, 2011. To date, there has been no notice of appeal.

Notes to the Consolidated Financial Statements

On March 2, 2011, the City of Marianna, Florida filed a declaratory action against FPU in the Circuit Court of the Fourteenth judicial Circuit in and for Jackson County, Florida, alleging that FPU breached its obligations under its franchise with the city to provide electric service to customers within and without the city by failing (i) to develop and implement TOU and interruptible rates that were mutually agreed to by the city and FPU; (ii) to have such mutually agreed upon rates in effect by February 17,2011; and (iii) to have such rates available to all of FPU s customers located within and without the corporate limits of the city. The city is seeking a declaratory judgment to exercise its option under the franchise agreement to purchase FPU s property (consisting of the electric distribution assets) within the City of Marianna. Any such purchase would be subject to approval by the Commission which would also need to approve the presentation of a referendum to voters in the City of Marianna for approval of the purchase and the operation by the city of an electric distribution facility. If the purchase is approved by the Commission and the voters in the City of Marianna, the closing of the purchase must occur within 12 months after the referendum is approved. FPU intends to file a response to the City s complaint and vigorously contest this litigation and intends to oppose the passage of any proposed referendum that is presented to voters to approve the purchase of the FPU property in the City of Marianna.

Natural Gas, Electric and Propane Supply

Our natural gas, electric and propane distribution operations have entered into contractual commitments to purchase gas and electricity from various suppliers. The contracts have various expiration dates. In March 2009, we renewed our contract with an energy marketing and risk management company to manage a portion of our natural gas transportation and storage capacity. This contract expires on March 31, 2012.

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 Public Service Commission (Florida PSC), all of the capacity under these agreements has been released to various third-parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake is contingently liable to FGT and Gulfstream, should any party that acquired the capacity through release fail to pay for the service.

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

FPU s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU s agreement with JEA requires FPU to comply with the following ratios based on the result of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times and (b) fixed charge coverage ratio greater than 1.5. If either ratio is not met by FPU, it has 30 days to cure the default or provide an irrevocable letter of credit if the default is not cured. FPU s agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operation interest coverage ratio (minimum of 2 times) and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of action taken or proposed to be taken to be compliant. Failure to comply with the ratios specified in the Gulf Power agreement could result in FPU providing an irrevocable letter of credit. FPU was in compliance with these requirements as of December 31, 2010.

Corporate Guarantees

The Board of Directors has authorized the Company to issue up to $35 million of corporate guarantees on behalf of our subsidiaries and for letters of credit. As of March 2, 2011, the Board increased this limit from $35 million to $45 million.

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily the propane wholesale marketing subsidiary and our natural gas marketing subsidiary. These corporate guarantees provide for the payment of propane and natural gas purchases in the event of the respective subsidiary s default. Neither subsidiary has ever defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in the Consolidated Financial Statements when incurred. The aggregate amount guaranteed at December 31, 2010 was $25.6 million, with the guarantees expiring on various dates in 2011.

In addition to the corporate guarantees, we have issued a letter of credit to our primary insurance company for $440,625 which expires on December 2, 2011. The letter of credit is provided as security to satisfy the deductibles under our various outstanding insurance policies. As a result of the recent change in our primary insurance company, we have issued an additional letter of credit for $725,000 to our former primary insurance company, which will expire on June 1, 2011. There have been no draws on these letters of credit as of December 31, 2010. We do not anticipate that the letters of credit will be drawn upon by the counterparties and we expect that the letters of credit will be renewed to the extent necessary in the future.

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Notes to the Consolidated Financial Statements

We provided a letter of credit for $2.0 million to TETLP related to the Precedent Agreement with TETLP, which is further described below.

Agreements for Access to New Natural Gas Supplies

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

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

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

The Precedent Agreement requires us to reimburse TETLP for our proportionate share of TETLP s pre-service costs incurred to date, if we terminate the Precedent Agreement, are unwilling or unable to perform our material duties and obligations thereunder, or take certain other actions whereby TETLP is unable to obtain the authorizations and exemptions required for this project. If such termination were to occur, we estimate that our proportionate share of TETLP s pre-service costs could be approximately $4.7 million as of December 31, 2010. If we were to terminate the Precedent Agreement after TETLP completed its construction of all facilities, which is expected to be in the fourth quarter of 2011, our proportionate share could be as much as approximately $45 million. The actual amount of our proportionate share of such costs could differ significantly and would ultimately be based on the level of pre-service costs at the time of any potential termination. As our Delaware and Maryland divisions have now executed the required reservation rate agreements with TETLP, we believe that the likelihood of terminating the Precedent Agreement and having to reimburse TETLP for our proportionate share of TETLP s pre-service costs is remote.

As of December 31, 2010, we provided a letter of credit for $2.0 million under the Precedent Agreement with TETLP as required. This letter of credit is expected to increase quarterly as TETLP s pre-service costs increase and will not exceed more than the three-month reservation charge under the firm transportation service contracts, which we currently estimate to be $2.1 million.

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

Notes to the Consolidated Financial Statements

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

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

Non-income-based Taxes

From time to time, we are subject to various audits and reviews by the states and other regulatory authorities regarding non-income-based taxes. We are currently undergoing a sales tax audit in Florida. During 2010, we recorded an accrual of $698,000 related to additional sales taxes and gross receipts taxes owed to various states.

Other Contingency

In 2010, we recorded a $750,000 accrual related to the regulatory risk for FPU s natural gas distribution operation associated with its earnings, merger benefits and recovery of its purchase premium (See Note O, Rates and Other Regulatory Activities, to the Consolidated Financial Statements for further discussion).

R. 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**
(in thousands except per share amounts)				
2010				
Operating Revenue	**$ 153,260**	**$ 80,061**	**$ 76,466**	**$ 117,759**
Operating Income	**$ 25,398**	**$ 7,761**	**$ 4,583**	**$ 14,188**
Net Income	**$ 13,974**	**$ 3,340**	**$ 1,628**	**$ 7,113**
Earnings per share:				
Basic	**$ 1.48**	**$ 0.35**	**$ 0.17**	**$ 0.75**
Diluted	**$ 1.47**	**$ 0.35**	**$ 0.17**	**$ 0.74**
2009[1]				
Operating Revenue	$ 104,479	$ 40,834	$ 31,758	$ 91,715
Operating Income	$ 15,966	$ 2,856	$ 2,257	$ 12,658
Net Income	$ 8,593	$ 806	$ 308	$ 6,191
Earnings per share:				
Basic	$ 1.26	$ 0.12	$ 0.04	$ 0.71
Diluted	$ 1.24	$ 0.12	$ 0.04	$ 0.71

(1) The quarterly results prior to the completion of the merger with FPU exclude the result from FPU. The merger became effective on October 28, 2009.

(2) The sum of the four quarters does not equal the total year due to rounding.

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, 2010. 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, 2010.

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, 2010, that materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

On October 28, 2009, the previously announced merger between Chesapeake and FPU was consummated. Chesapeake has included FPU s activity in its evaluation of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. See Item 8 under the heading Notes to the Consolidated Financial Statements Note B, Acquisitions for additional information relating to the FPU merger.

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, 2010. In addition, on June 3, 2010 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

The report of management required under this Item 9A is contained in Item 8 of this Form 10-K under the caption Management s Report on Internal Control over Financial Reporting.

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

To 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, 2010, 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 appearing under Item 8. 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, 2010, 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, 2010 and 2009, and the related consolidated statements of income, stockholders equity and cash flows of Chesapeake Utilities Corporation, and our report dated March 8, 2011 expressed an unqualified opinion.

/s/ ParenteBeard LLC

ParenteBeard LLC
Malvern, Pennsylvania
March 8, 2011

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Item 9B. Other Information.

None

Part III

Item 10. Directors, Executive Officers of the Registrant and Corporate Governanace.

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, 2011, in connection with the Company s Annual Meeting to be held on or about May 4, 2011.

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 Company.

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 portion 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, 2011, in connection with the Company s Annual Meeting to be held on or about May 4, 2011.

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, 2011, in connection with the Company s Annual Meeting to be held on or about May 4, 2011.

The following table sets forth information, as of December 31, 2010, 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			402,843(1)
Equity compensation plans not approved by security holders			
Total			402,843

(1) Includes 345,028 shares under the 2005 Performance Incentive Plan, 34,215 shares available under the 2005 Directors Stock Compensation Plan, and 23,600 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 portions of the Proxy Statement captioned, Corporate Governance, to be filed no later than March 31, 2011 in connection with the Company s Annual Meeting to be held on or about May 4, 2011.

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 not later than March 31, 2011, in connection with the Company s Annual Meeting to be held on or about May 4, 2011.

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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, 2010, 2009, and 2008;

   Consolidated Balance Sheets at December 31, 2010 and December 31, 2009;

   Consolidated Statements of Cash Flows for each of the three years ended December 31, 2010, 2009, and 2008;

   Consolidated Statements of Stockholders Equity for each of the three years ended December 31, 2010, 2009, and 2008; and

   Notes to the Consolidated Financial Statements.

2. **Financial Statement Schedules:**

   Report of Independent Registered Public Accounting Firm;

   Schedule I Parent Company Condensed Financial Statements; 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 1.1 Underwriting Agreement entered into by Chesapeake Utilities Corporation and Robert W. Baird & Co. Incorporated and A.G. Edwards & Sons, Inc., on November 15, 2006 relating to the sale and issuance of 600,300 shares of Chesapeake s common stock, is incorporated herein by reference to Exhibit 1.1 of our Current Report on Form 8-K, filed November 16, 2006, File No. 001-11590.

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.

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 April 7, 2010, are incorporated herein by reference to Exhibit 3 of the Company s Current Report on Form 8-K, filed April 13, 2010, File No. 001-11590.

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 the Company on October 2, 1995, pursuant to which Chesapeake privately placed $10 million of its 6.91% Senior Notes, paid off in 2010, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. We hereby agree to furnish a copy of that agreement to the SEC upon request.

Exhibit 4.3	Note Purchase Agreement, entered into by Chesapeake on December 15, 1997, pursuant to which Chesapeake privately placed $10 million of its 6.85% Senior Notes due in 2012, is incorporated by reference to Exhibit 4.3 of our Annual Report on Form 10-K for the year ended December 31, 2009, File No. 001-11590.
Exhibit 4.4	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 4.5	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.
Exhibit 4.6	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 4.7	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 4.8	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 4.9	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 filed herewith.
Exhibit 4.10	Fifteenth Supplemental Indenture entered into by Florida Public Utilities Company on November 1, 2001, pursuant to which Florida Public Utilities Company, on November 1, 2001, privately placed $14,000,000 of its 4.90% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4(c) of Florida Public Utilities Company s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-10608.
Exhibit 4.11	Fourteenth Supplemental Indenture entered into by Florida Public Utilities Company on September 1, 2001, pursuant to which Florida Public Utilities Company, on September 1, 2001, privately placed $15,000,000 of its 6.85% First Mortgage Bonds, is incorporated herein by reference to Exhibit 4(b) of Florida Public Utilities Company s Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-10608.

Exhibit 4.12	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 4.13	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.

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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.
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 filed herewith.
Exhibit 10.7*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.8*	Consulting Agreement dated January 3, 2011, by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is filed herewith.
Exhibit 10.9*	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 10.10*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.11*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.12*	Executive Employment Agreement dated December 31, 2009, by and between Chesapeake Utilities Corporation and Joseph Cummiskey, is incorporated herein by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed January 7, 2010, File No. 001-11590.
Exhibit 10.13*	

	Executive Employment Agreement dated March 3, 2011, by and between Chesapeake Utilities Corporation and Elaine B. Bittner, is filed herewith.
Exhibit 10.14*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.11 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.

Exhibit 10.15*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and John R. Schimkaitis, is incorporated herein by reference to Exhibit 10.12 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.16*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.13 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.17*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Michael P. McMasters, is incorporated herein by reference to Exhibit 10.14 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.18*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.15 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.19*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.16 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.20*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.17 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.21*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Beth W. Cooper, is incorporated herein by reference to Exhibit 10.18 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.22*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2009, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and S. Robert Zola, is incorporated herein by reference to Exhibit 10.19 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.23*	Performance Share Agreement dated January 23, 2008 for the period 2008 to 2010, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake

	Utilities Corporation and S. Robert Zola, is incorporated herein by reference to Exhibit 10.20 of our Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-11590.
Exhibit 10.24*	Form of Performance Share Agreement effective January 7, 2009 for the period 2009 to 2011, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of John R. Schimkaitis, Michael P. McMasters, Beth W. Cooper and Stephen C. Thompson, is incorporated herein by reference to Exhibit 10.26 on Form 10-K for the year ended December 31, 2008, File No. 001-11590.

Exhibit 10.25*	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 John R. Schimkaitis, Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, and Joseph Cummiskey 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 10.26*	Performance Share Agreement dated January 20, 2010 for the period 2010 to 2011, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and Joseph Cummiskey 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 10.27*	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 Cummiskey, 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 10.28*	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 filed herewith.
Exhibit 10.29*	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 10.30*	First Amendment to the Chesapeake Utilities Corporation Supplemental Executive Retirement Plan as amended and restated effective January 1, 2009, is filed herewith.
Exhibit 10.31*	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 10.32*	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 10.33	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 10.34	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 10.35	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 10.36	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 10.37	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 10.38	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.
Exhibit 10.39	Term Note Agreement entered into by Chesapeake Utilities Corporation on March 16, 2010, pursuant to the $29 million credit facility with PNC Bank, N.A., is incorporated herein by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, File No. 001-11590.
Exhibit 10.40	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 10.41	Form of Franchise Agreement between Florida Public Utilities Company and the city of Marianna, effective February 1, 2010, is filed herewith.
Exhibit 10.42	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 by reference as 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 10.43	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 filed herewith.
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, 2011, 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, 2011, 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, 2011, 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, 2011, 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, 2011

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	/s/ Michael P. McMasters
Ralph J. Adkins, Chairman of the Board and Director Date: March 2, 2011	Michael P. McMasters, President, Chief Executive Officer and Director Date: March 8, 2011
/s/ Beth W. Cooper	/s/ Eugene H. Bayard
Beth W. Cooper, Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer) Date: March 8, 2011	Eugene H. Bayard, Director Date: March 2, 2011
/s/ Richard Bernstein	/s/ Thomas J. Bresnan
Richard Bernstein, Director Date: March 2, 2011	Thomas J. Bresnan, Director Date: March 7, 2011
/s/ Thomas P. Hill, Jr.	/s/ Dennis S, Hudson, III
Thomas P. Hill, Jr., Director Date: March 2, 2011	Dennis S. Hudson, III, Director Date: March 2, 2011
/s/ Paul L. Maddock, Jr.	/s/ J. Peter Martin
Paul L. Maddock, Jr., Director Date: March 2, 2011	J. Peter Martin, Director Date: March 2, 2011
/s/ Joseph E. Moore, Esq	/s/ Calvert A. Morgan, Jr
Joseph E. Moore, Esq., Director Date: March 2, 2011	Calvert A. Morgan, Jr., Director Date: March 2, 2011
/s/ Dianna F. Morgan	/s/ John Schimkaitis

Dianna F. Morgan, Director	John R. Schimkaitis
Date: March 2, 2011	Vice Chairman of the Board and Director
	Date: March 2, 2011

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Chesapeake Utilities Corporation

The audit referred to in our report dated March 8, 2011 relating to the consolidated financial statements of Chesapeake Utilities Corporation as of December 31, 2010 and 2009 and for each of the years in the three-year period ended December 31, 2010, which is contained in Item 8 of this Form 10-K also included the audits of the financial statement schedules listed in Item 15(a)2. These financial statement schedules are the responsibility of the Chesapeake Utilities Corporation s management. Our responsibility is to express an opinion on these financial statement schedules based on our audits.

In our opinion such financial statement schedules, 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
Malvern, Pennsylvania
March 8, 2011

Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements
Chesapeake Utilities Corporation (Parent)
Condensed Balance Sheets

Assets *(in thousands)*	**December 31, 2010**	**December 31, 2009**
Total property, plant and equipment	**$ 202,807**	$ 191,440
Less: Accumulated depreciation and amortization	**(49,223)**	(46,297)
Plus: Construction work in progress	**1,492**	1,338
Net property, plant and equipment	**155,076**	146,481
Investments, at fair value	**2,368**	1,959
Investments in subsidiaries	**179,580**	160,150
Current Assets		
Cash and cash equivalents	**4,229**	973
Accounts receivable (less allowance for uncollectible accounts of $432 and $458, respectively)	**11,623**	9,356
Accrued revenue	**6,458**	4,936
Accounts receivable from affiliates	**74,663**	56,587
Propane inventory, at average cost	**635**	624
Other inventory, at average cost	**970**	971
Regulatory assets	**51**	1,205
Storage gas prepayments	**5,084**	6,144
Income taxes receivable	**4,003**	822
Deferred income taxes	**369**	1,909
Prepaid expenses	**2,310**	3,047
Other current assets	**176**	79
Total current assets	**110,571**	86,653
Deferred Charges and Other Assets		
Long-term receivables	**133**	331
Regulatory assets	**2,820**	3,610
Other deferred charges	**603**	479
Total deferred charges and other assets	**3,556**	4,420
Total Assets	**$ 451,151**	$ 399,663

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

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Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements
Chesapeake Utilities Corporation (Parent)
Condensed Balance Sheets

Capitalization and Liabilities *(in thousands)*	**December 31, 2010**	December 31, 2009
Capitalization		
Stockholders equity		
Common stock, par value $0.4867 per share (authorized 25,000,000 and 12,000,000 shares, respectively)	**$ 4,635**	$ 4,572
Additional paid-in capital	**148,159**	144,502
Retained earnings	**76,805**	63,231
Accumulated other comprehensive loss	**(3,134)**	(2,865)
Deferred compensation obligation	**777**	739
Treasury stock	**(777)**	(739)
Total stockholders equity	**226,465**	209,440
Long-term debt, net of current maturities	**71,682**	79,611
Total capitalization	**298,147**	289,051
Current Liabilities		
Current portion of long-term debt	**7,727**	6,636
Short-term borrowing	**63,958**	30,023
Accounts payable	**10,401**	9,157
Customer deposits and refunds	**7,619**	4,410
Accrued interest	**1,015**	1,003
Dividends payable	**3,143**	2,959
Accrued compensation	**3,377**	2,450
Regulatory liabilities	**2,432**	5,934
Other accrued liabilities	**2,635**	1,647
Total current liabilities	**102,307**	64,219
Deferred Credits and Other Liabilities		
Deferred income taxes	**20,999**	16,494
Deferred investment tax credits	**122**	157
Regulatory liabilities	**709**	695
Environmental liabilities	**358**	531
Other pension and benefit costs	**5,045**	5,674
Accrued asset removal cost Regulatory liability	**18,805**	18,248

Other liabilities		**4,659**		4,594
Total deferred credits and other liabilities		**50,697**		46,393
Other commitments and contingencies				
Total Capitalization and Liabilities	**$**	**451,151**	$	399,663

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

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Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements
Chesapeake Utilities Corporation (Parent)
Condensed Statements of Income

For the Years Ended December 31, *(in thousands)*	**2010**	**2009**	**2008**
Operating Revenues	**$ 95,764**	$ 101,577	$ 103,733
Operating Expenses			
Cost of sales	**52,295**	62,339	65,446
Operations	**19,919**	18,487	16,039
Transaction-related costs	**660**	1,478	1,153
Maintenance	**1,165**	1,535	1,303
Depreciation and amortization	**4,365**	4,194	3,918
Other taxes	**3,788**	3,564	3,380
Total operating expenses	**82,192**	91,597	91,239
Operating Income	**13,572**	9,980	12,494
Income from equity investments	**19,430**	12,042	7,781
Other loss, net of other expenses	**(30)**	(30)	(106)
Interest charges	**2,837**	3,066	3,026
Income Before Income Taxes	**30,135**	18,926	17,143
Income taxes	**4,079**	3,029	3,536
Net Income	**$ 26,056**	$ 15,897	$ 13,607

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

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Chesapeake Utilities Corporation and subsidiaries
Schedule I
Parent Company Condensed financial statements
Chesapeake Utilities Corporation (Parent)
Condensed Statement of Cash Flows

For the Years Ended December 31, *(in thousands)*	**2010**	2009	2008
Operating Activities			
Net Income	**$ 26,056**	$ 15,897	$ 13,607
Adjustments to reconcile net income to net operating cash:			
Equity earnings in subsidiaries	**(19,382)**	(12,042)	(7,781)
Depreciation and amortization	**4,366**	4,190	3,918
Depreciation and accretion included in other costs	**1,878**	1,773	1,389
Deferred income taxes, net	**6,901**	2,821	5,147
Unrealized (gain) loss on investments	**(113)**	(212)	509
Employee benefits and compensation	**(169)**	1,217	152
Share based compensation	**1,155**	1,306	820
Other, net	**(46)**	8	11
Changes in assets and liabilities:			
Purchase of investments	**(297)**	(146)	(201)
Accounts receivable and accrued revenue	**(3,814)**	(16,770)	(3,016)
Propane inventory, storage gas and other inventory	**1,050**	3,383	(3,854)
Regulatory assets	**1,716**	(1,825)	606
Prepaid expenses and other current assets	**653**	(1,050)	(516)
Other deferred charges	**(180)**	(72)	(8)
Long-term receivables	**198**	181	199
Accounts payable and other accrued liabilities	**1,636**	9,832	3,323
Income taxes receivable	**(3,858)**	2,791	(3,113)
Accrued interest	**12**	(20)	158
Customer deposits and refunds	**3,208**	(1,147)	34
Accrued compensation	**823**	352	377
Regulatory liabilities	**(3,488)**	3,603	(2,379)
Other liabilities	**64**	886	(23)
Net cash provided by operating activities	**18,369**	14,956	9,359
Investing Activities			
Property, plant and equipment expenditures	**(13,969)**	(12,615)	(16,328)
Proceeds from investments		1,000	500
Cash acquired in the merger, net of cash paid		(16)	
Environmental expenditures	**54**	(86)	(480)
Net cash used in investing activities	**(13,915)**	(11,717)	(16,308)
Financing Activities			

Change in receivable/payable with affiliates		**(18,051)**		13,379		4,302
Common stock dividends		**(11,013)**		(7,957)		(7,810)
Issuance of stock for Dividend Reinvestment Plan		**568**		392		(118)
Change in cash overdrafts due to outstanding checks		**3,256**		835		(684)
Net borrowing (repayment) under line of credit agreements		**1,579**		(3,812)		(11,980)
Other short-term borrowing		**29,100**				
Proceeds from issuance of long-term debt						29,961
Repayment of long-term debt		**(6,637)**		(6,637)		(7,637)
Net cash provided by (used in) financing activities		**(1,198)**		(3,800)		6,034
Net Increase (Decrease) in Cash and Cash Equivalents		**3,256**		(561)		(915)
Cash and Cash Equivalents Beginning of Period		**973**		1,534		2,449
Cash and Cash Equivalents End of Period	**$**	**4,229**	$	973	$	1,534

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

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Chesapeake Utilities Corporation and Subsidiaries
Schedule I
Parent Company Condensed Financial Statements

Notes to Financial Information

These condensed financial statements represent the financial information of Chesapeake Utilities Corporation (parent company).

For information concerning Chesapeake s debt obligations, see Item 8 under the heading Notes to the Consolidated Financial Statements Note J, Long-term Debt, and Note K, Short-term Borrowing.

For information concerning Chesapeake s material contingencies and guarantees, see Item 8 under the heading Notes to the Consolidated Financial Statements Note P, Environmental Commitments and Contingencies and Note Q, Other Commitments and Contingencies.

Chesapeake s wholly-owned subsidiaries are accounted for using the equity method of accounting.

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Chesapeake Utilities Corporation and Subsidiaries
Schedule II
Valuation and Qualifying Accounts

For the Year Ended December 31, Reserve Deducted From Related Assets Reserve for Uncollectible Accounts *(In thousands)*	Balance at Beginning of Year	Additions: Charged to Income	Additions: Other Accounts (1)	Deductions (2)	Balance at End of Year
2010	**$ 1,609**	**$ 1,129**	**$ 181**	**$ (1,725)**	**$ 1,194**
2009	$ 1,159	$ 1,138	$ 616	$ (1,304)	$ 1,609
2008	$ 952	$ 1,186	$ 241	$ (1,220)	$ 1,159

(1) Recoveries.

(2) Uncollectible accounts charged off.