

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, 1998

Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION

(Exact name of registrant as specified in its charter)

State of Delaware
(State or other jurisdiction of
incorporation or organization)
No.)

51-0064146
(I.R.S. Employer
Identification

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: Common Stock - par value per share \$.4867 Name of each exchange on which registered: New York Stock Exchange, Inc.

SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:

Title of class: 8.25% Convertible Debentures Due 2014

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes . No .

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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.

As of March 26, 1999, 5,115,971 shares of common stock were outstanding. The aggregate market value of the common shares held by non-affiliates of Chesapeake Utilities Corporation, based on the last trade price on March 26, 1999, as reported by the New York Stock Exchange, was approximately \$67 million.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 1999 Annual Meeting of Stockholders are incorporated by reference in Part III.

CHESAPEAKE UTILITIES CORPORATION
FORM 10-K

YEAR ENDED DECEMBER 31, 1998

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PART I

Item 1. Business

(a) General Development of Business Chesapeake Utilities Corporation ("Chesapeake" or "the Company") is a diversified utility company engaged primarily in natural gas distribution and transmission, propane distribution and marketing and advanced information services.

Chesapeake's three natural gas distribution divisions serve approximately 37,100 residential, commercial and industrial customers in southern Delaware, Maryland's Eastern Shore and Central Florida. The Company's natural gas transmission subsidiary, Eastern Shore Natural Gas Company ("Eastern Shore"), operates a 273-mile interstate pipeline system that transports gas from various points in Pennsylvania to the Company's Delaware and Maryland distribution divisions, as well as to other utilities and industrial customers in Delaware and on the Eastern Shore of Maryland. The Company's propane distribution operation serves approximately 35,000 customers in southern Delaware and on the Eastern Shore of Maryland and Virginia. The advanced information services segment provides consulting, custom programming, training and development tools for national and international clients.

(b) Financial Information about Industry Segments Financial information by business segment is included in Item 7 under the heading "Notes to Consolidated Financial Statements - Note C".

(c) Narrative Description of Business The Company is engaged in four primary business activities: natural gas transmission, natural gas distribution, propane distribution and marketing and advanced information services. In addition to the four primary groups, Chesapeake has four subsidiaries engaged in other service-related businesses.

(i) (a) Natural Gas Transmission General Eastern Shore, the Company's wholly owned transmission subsidiary, operates an interstate natural gas pipeline and provides open access transportation services for affiliated and non-affiliated companies through an integrated gas pipeline extending from southeastern Pennsylvania to Delaware and the Eastern Shore of Maryland. Eastern Shore also provides contract storage services as well as the purchase and sale of small quantities of gas for system balancing purposes ("swing gas"). Eastern Shore's rates are subject to regulation by the Federal Energy Regulatory Commission ("FERC").

Adequacy of Resources

Eastern Shore has 4,916 thousand cubic feet ("Mcf") of firm transportation capacity under Rate Schedule FT under contract with Transcontinental Gas Pipe Line Corporation ("Transco") which expires in 2005. Eastern Shore also has 7,046 Mcf of firm peak day entitlements and total storage capacity of 278,264Mcf under Rate Schedules GSS, LSS and LGA, respectively, under contract with Transco. The GSS and LSS contracts expire in 2013 and the LGA contract expires in 2006.

Eastern Shore also has firm storage service under Rate Schedule FSS and firm storage transportation capacity under Rate Schedule SST under contract with Columbia Gas Transmission ("Columbia"). These contracts, which expire in 2004, provide for 1,073 Mcf of firm peak day entitlement and total storage capacity of 53,738 Mcf.

Eastern Shore has retained the firm transportation capacity and firm storage services described above in order to provide swing transportation service to those customers that requested such service.

Competition

Under the open access environment, interstate pipeline companies have unbundled the traditional components of their service - gas gathering, transportation and storage - from the sale of the commodity. Pipelines that choose to be merchants of gas must form separate marketing operations independent of their pipeline operations. Hence, gas marketers have developed as a viable option for many companies because they are providing expertise in gas purchasing along with collective purchasing capabilities which, when combined, may reduce the end-user cost. Additional discussion on competition is included in Item 7 under the heading "Management's Discussion and Analysis - Competition".

Rates and Regulation

General. Eastern Shore is subject to regulation by the FERC as an interstate pipeline. The FERC regulates the provision of service, terms and conditions of service, and the rates and fees Eastern Shore can charge to its transportation customers. In addition, the FERC regulates the rates Eastern Shore is charged for transportation and transmission line capacity and services provided by Transco and Columbia.

Regulatory Proceedings

Amendment to Rt. 72 and Porter Road filing. On March 6, 1998, the FERC authorized Eastern Shore to replace 2.3 miles of 6-inch pipeline with 10- inch pipeline along Route 72 and Power Road, all in conjunction with a Delaware Department of Transportation highway relocation project. On September 15, 1998, Eastern Shore filed an amendment in Docket No. CP97- 279-001 requesting that the FERC authorize an increase in the diameter of the previously approved 2.3-mile pipeline from 10 inches to 16 inches. Eastern Shore filed this amendment in connection with the 1999 System Expansion described below. The FERC issued an Order Amending Certificate in this docket on October 16, 1998, approving Eastern Shore's proposal. Construction has started and is expected to be completed during 1999.

1999 System Expansion. On September 25, 1998, Eastern Shore filed an application before the FERC requesting authorization to construct and operate a total of eight miles (4.5 miles in Pennsylvania and 3.5 miles in Delaware) of 16-inch pipeline looping on Eastern Shore's existing system and to install 1,085 horsepower of additional compression at its Delaware City compressor station. The purpose of these new facilities is to enable Eastern Shore to provide 16,540 dekatherms of additional firm transportation capacity on its system for two existing customers, Delmarva Power and Light Company and Star Enterprise. The proposed expansion has been targeted for completion on November 1, 1999. The estimated project cost is approximately \$7.0 million and is expected to generate approximately \$1.8 million in additional annual revenue.

Eastern Shore also requested the FERC to issue a preliminary determination of rolled-in treatment of the costs incurred in this project into existing rates. The Company is awaiting FERC approval.

Rate Case Filing. In October 1996, Eastern Shore filed for a general rate increase with the FERC. The filing proposed an increase in Eastern Shore's jurisdictional rates that would generate additional annual operating revenue of approximately \$1.4 million. Eastern Shore also stated in the filing that it intended to use the cost-of-service submitted in the general rate increase filing to develop rates in the pending Open Access Docket. In September 1997, the FERC approved a rate increase of \$1.2 million.

Open Access Filing. In December 1995, Eastern Shore filed its abbreviated application for a blanket certificate of public convenience and necessity authorizing the transportation of natural gas on behalf of others. Eastern Shore proposed to unbundle the sales and storage services it had provided. Customers who had previously received firm sales and storage services on Eastern Shore (the "Converting Customers") would receive entitlements to firm transportation service on Eastern Shore's pipeline in a quantity equivalent to their existing service rights. Eastern Shore proposed to retain some of its pipeline entitlements and storage capacity for operational issues and to facilitate "no-notice" (no prior notification required to receive service) transportation service on its pipeline system. Eastern Shore would release or assign to the remaining Converting Customers the firm transportation capacity, including contract storage, it held on its upstream pipelines so that the Converting Customers would be able to become direct customers of such upstream pipelines. Converting Customers who previously received bundled sales service having no-notice characteristics would have the right to elect no-notice firm transportation service.

In connection with the rate increase settlement, the issues listed above pertaining to Eastern Shore operating as an open access pipeline were also settled in September 1997, with open access implementation occurring on November 1, 1997.

Delaware City Compressor Station Filing. In December 1995, Eastern Shore filed an application before the FERC pursuant to Sections 7(b) and (c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing Eastern Shore to: (1) construct and operate a 2,170 horsepower compressor station in Delaware City, New Castle County, Delaware on a portion of its existing pipeline system known as the "Hockessin Line", such new station to be known as the "Delaware City Compressor Station"; (2) construct and operate slightly less than one mile of 16-inch pipeline in Delaware City, New Castle County, Delaware to tie the suction side of the proposed Delaware City Compressor Station into the Hockessin Line; and (3) increase the maximum allowable operating pressure on 28.7 miles of Eastern Shore's pipeline from Eastern Shore's existing Bridgeville Compressor Station in Bridgeville, Sussex County, Delaware to its terminus in Salisbury, Wicomico County, Maryland.

In September 1996 the FERC issued its Final Order, which: authorized Eastern Shore to: (1) construct and operate the facilities requested in its application; (2) roll-in the cost of the facilities into its existing rates if the revenues from the increase in services exceed the cost associated with the expansion portion of the project; and (3) abandon the 100 Mcf per day of firm sale service to one of its direct sale customers. The FERC's Final Order also denied Eastern Shore the authority to increase the level of sales and storage service it provides its customers until it completes its restructuring in its open access proceeding. The compressor facility and associated piping were needed to stabilize capacity on Eastern Shore's system as a result of steadily declining inlet pressures at the Hockessin interconnect with Transcontinental Gas Pipe Line Corporation. Construction of the facilities started during the second half of 1996 and was completed during the first quarter of 1997.

(i) (b) Natural Gas Distribution General Chesapeake distributes natural gas to approximately 37,100 residential, commercial and industrial customers in southern Delaware, the Salisbury and Cambridge, Maryland areas on Maryland's Eastern Shore, and Central Florida. These activities are conducted through three utility divisions, one division in Delaware, another in Maryland and a third division in Florida. In 1993, the Company started natural gas supply management services in the state of Florida under the name of Peninsula Energy Services Company ("PESCO").

Delaware and Maryland. The Delaware and Maryland divisions serve an average of approximately 27,900 customers, of which approximately 27,800 are residential and commercial customers purchasing gas primarily for heating purposes. Annually, residential and commercial customers account for approximately 56% of the volume delivered by the divisions and 75% of the divisions' revenue. The divisions' industrial customers purchase gas, primarily on an interruptible basis, for a variety of manufacturing, agricultural and other uses. Most of Chesapeake's customer growth in these divisions comes from new residential construction using gas heating equipment.

Florida. The Florida division distributes natural gas to an average of approximately 9,100 residential and commercial and 90 industrial customers in Polk, Osceola and Hillsborough Counties. Currently 41 of the division's industrial customers, which purchase and transport gas on a firm and interruptible basis, account for approximately 89% of the volume delivered by the Florida division and 50% of the division's annual natural gas and transportation revenues. These customers are primarily engaged in the citrus and phosphate industries and electric cogeneration. The Company's Florida division also provides natural gas supply management services to compete in the open access environment. Currently, twenty-two customers receive such services, which generated net income of \$66,000 in 1998.

Adequacy of Resources

General. Chesapeake's Delaware and Maryland utility divisions ("Delaware", "Maryland" or "the Divisions") have firm and interruptible contracts with four (4) interstate "open access" pipelines. The Divisions are directly interconnected with Eastern Shore and services upstream of Eastern Shore are contracted with Transco, Columbia, and Columbia Gulf Transmission Company ("Gulf"). The Divisions use their firm supply sources to meet a significant percentage of their projected demand requirements. In order to meet the difference between firm supply and firm

demand, Delaware and Maryland obtain gas supply on the "spot market" from various other suppliers that is transported by the upstream pipelines and delivered to the Divisions' interconnects with Eastern Shore as needed. The Company believes that Delaware and Maryland's available firm and "spot market" supply is ample to meet the anticipated needs of their customers.

Delaware. Delaware's contracts with Transco include: (a) firm transportation capacity of 8,663 dekatherms ("Dt") per day, which expires in 2005; (b) firm transportation capacity of 311 Dt per day for December through February, expiring in 2006; and (c) firm storage service, providing a total capacity of 142,830 Dt. Delaware and Transco are currently engaged in negotiations with regard to an extension of the term of the firm storage service. Although the original contract expired in 1998, Transco and Delaware have continued under the previous terms and conditions until an agreement is finalized.

Delaware's contracts with Columbia include: (a) firm transportation capacity of 852 Dt per day, which expires in 2004; (b) firm transportation capacity of 1,132 Dt per day, which expires in 2017; (c) firm transportation capacity of 549 Dt per day, which expires in 2018; (d) firm storage service providing a peak day entitlement of 6,193 Dt and a total capacity of 298,195 Dt, expiring in 2004; and (f) firm storage service, providing a peak day entitlement of 583 Dt per day and a total capacity of 52,460 Dt, which expires in 2018. Delaware's contracts with Columbia for storage related transportation provide quantities that are equivalent to the peak day entitlement for the period of October through March and are equivalent to fifty percent (50%) of the peak day entitlement for the period of April through September. The terms of the storage related transportation contracts mirror the storage services that they support.

Delaware's contract with Gulf, which expires in 2004, provides firm transportation capacity of 868 Dt per day for the period November through March and 798 Dt per day for the period April through October.

Delaware's contracts with Eastern Shore include: (a) firm transportation capacity of 25,560 Dt per day for the period December through February, 24,338 Dt per day for the months of November, March and April, and 15,262 Dt per day for the period May through October, with various expiration dates ranging from 2004 to 2017; (b) firm storage capacity under Eastern Shore's Rate Schedule GSS providing a peak day entitlement of 2,655 Dt and a total capacity of 131,370 Dt, which expires in 2013; (c) firm storage capacity under Eastern Shore's Rate Schedule LSS providing a peak day entitlement of 580 Dt and a total capacity of 29,000 Dt, which expires in 2013; and (d) firm storage capacity under Eastern Shore's Rate Schedule LGA providing a peak day entitlement of 911 Dt and a total capacity of 5,708 Dt, which expires in 2006. Delaware's firm transportation contracts with Eastern Shore also include Eastern Shore's provision of swing transportation service. This service includes: (a) firm transportation capacity of 1,846 Dt per day on Transco's pipeline system, retained by Eastern Shore, in addition to Delaware's Transco capacity referenced earlier and (b) an interruptible storage service under Transco's Rate Schedule ESS that supports a swing supply service provided under Transco's Rate Schedule FS.

Delaware currently has contracts for the purchase of firm natural gas supply with four (4) suppliers. These contracts provide the availability of a maximum firm daily entitlement of 12,200 Dt and the supplies are transported by Transco, Columbia, Gulf and Eastern Shore under Delaware's transportation contracts. The gas purchase contracts have various expiration dates.

Maryland. Maryland's contracts with Transco include: (a) firm transportation capacity of 4,738 Dt per day, which expires in 2005; (b) firm transportation capacity of 155 Dt per day for December through February, expiring in 2006; and (c) firm storage service providing a total capacity of 33,120 Dt. Maryland and Transco are currently engaged in negotiations with regard to an extension of the term of the firm storage service. Although the original contract expired in 1998, Transco and Maryland have continued under the previous terms and conditions until an agreement is finalized.

Maryland's contracts with Columbia include: (a) firm transportation capacity of 442 Dt per day, which expires in 2004; (b) firm transportation capacity of 908 Dt per day, which expires in 2017; (c) firm transportation capacity of 350 Dt per day, which expires in 2018; (d) firm storage service providing a peak day entitlement of 3,142 Dt and a total capacity of 154,756 Dt, which expires in 2004; and (e) firm storage service providing a peak day entitlement of 521 Dt and a total capacity of 46,881 Dt, which expires in 2017. Maryland's contracts with Columbia for storage related transportation provide quantities that are equivalent to the peak day entitlement for the period October through March and are equivalent to fifty percent (50%) of the peak day entitlement for the period April through September. The terms of the storage related transportation contracts mirror the storage services that they support.

Maryland's contract with Gulf, which expires in 2004, provides firm transportation capacity of 590 Dt per day for the period November through March and 543 Dt per day for the period April through October.

Maryland's contracts with Eastern Shore include: (a) firm transportation capacity of 13,378 Dt per day for the period December through February, 12,654 Dt per day for the months of November, March and April, and 8,093 Dt per day for the period May through October; (b) firm storage capacity under Eastern Shore's Rate Schedule GSS providing a peak day entitlement of 1,428 Dt and a total capacity of 70,665 Dt, which expires in 2013; (c) firm storage capacity under Eastern Shore's Rate Schedule LSS providing a peak day entitlement of 309 Dt and a total capacity of 15,500 Dt, which expires in 2013; and (d) firm storage capacity under Eastern Shore's Rate Schedule LGA providing a peak day entitlement of 569 Dt and a total capacity of 3,560 Dt, which expires in 2006. Maryland's firm transportation contracts with Eastern Shore also include Eastern Shore's provision of swing transportation service. This service includes: (a) firm transportation capacity of 969 Dt per day on Transco's pipeline system, retained by Eastern Shore, in addition to Maryland's Transco capacity referenced earlier and (b) an interruptible

storage service under Transco's Rate Schedule ESS that supports a swing supply service provided under Transco's Rate Schedule FS.

Maryland currently has contracts for the purchase of firm natural gas supply with four (4) suppliers. These contracts provide the availability of a maximum firm daily entitlement of 7,239 Dt and the supplies are transported by Transco, Columbia, Gulf and Eastern Shore under Maryland's transportation contracts. The gas purchase contracts have various expiration dates.

Florida. The Florida division receives transportation service from Florida Gas Transmission Company ("FGT"), a major interstate pipeline. Chesapeake has contracts with FGT for: (a) daily firm transportation capacity of 21,123 Dt in May through September, 27,105 Dt in October, and 27,519 Dt in November through April under FGT's firm transportation service (FTS-1) rate schedule; (b) daily firm transportation capacity of 5,100 Dt in May through October, and 8,100 Dt in November through April under FGT's firm transportation service (FTS-2) rate schedule; and (c) daily interruptible transportation capacity of 20,000 Dt under FGT's interruptible transportation services (ITS-1) rate schedule. The firm transportation contract (FTS-1) expires on August 1, 2000 with the Company retaining a unilateral right to extend the term for an additional ten years. After the expiration of the primary or secondary term, Chesapeake has the right to first refuse to match the terms of any competing bids for the capacity. The firm transportation contract (FTS-2) expires on March 1, 2015. The interruptible transportation contract is effective until August 1, 2010 and month to month thereafter unless canceled by either party with thirty days notice.

The Florida division currently receives its gas supply from various suppliers. If needed, some supply is bought on the spot market; however, the majority is bought under the terms of two firm supply contacts with Dynergy Marketing and Trade and Duke Energy. Availability of gas supply to the Florida division is also expected to be adequate under existing arrangements.

Competition

Competition with Alternative Fuels. Historically, the Company's natural gas distribution divisions have successfully competed with other forms of energy such as electricity, oil and propane. The principal consideration in the competition between the Company and suppliers of other sources of energy is price and, to a lesser extent, accessibility. All of the Company's divisions have the capability of adjusting their interruptible rates to compete with alternative fuels.

The divisions have several large volume industrial customers that have the capacity to use fuel oil as an alternative to natural gas. When oil prices decline, these interruptible customers convert to oil to satisfy their fuel requirements. Lower levels in interruptible sales occur when oil prices remain depressed relative to the price of natural gas. However, oil prices as well as the prices of other fuels are subject to change at any time for a variety of reasons; therefore, there is always uncertainty in the continuing competition among natural gas and other fuels. In order to address this uncertainty, the Company uses flexible pricing arrangements on both the supply and sales side of its business to maximize sales volumes.

To a lesser extent than price, availability of equipment and operational efficiency are also factors in competition among fuels, primarily in residential and commercial settings. Heating, water heating and other domestic or commercial equipment is generally designed for a particular energy source, and especially with respect to heating equipment, the cost of conversion is a disincentive for individuals and businesses to change their energy source.

Competition within the Natural Gas Industry. FERC Order 636 enables all natural gas suppliers to compete for customers on an equal footing. Under this open access environment, interstate pipeline companies have unbundled the traditional components of their service such as gas gathering, transportation and storage from the sale of the commodity. If they choose to be a merchant of gas, they must form a separate marketing operation independent of their pipeline operations. Hence, gas marketers have developed as a viable option for many companies because they are providing expertise in gas purchasing along with collective purchasing capabilities which, when combined, may reduce end-user cost.

Also resulting from an open access environment, the distribution division can be in competition with the interstate transmission company if the distribution customer is located close to the transmission company's pipeline. The customers at risk are usually large volume commercial and industrial customers with the financial resources and capability to bypass the distribution division. In certain situations the distribution divisions may adjust rates and services for these customers to retain their business.

Rates and Regulation

General. Chesapeake's natural gas distribution divisions are subject to regulation by the Delaware, Maryland and Florida Public Service Commissions with respect to various aspects of the Company's business, including the rates for sales to all of their customers in each jurisdiction. All of Chesapeake's firm distribution rates are subject to purchased gas adjustment clauses, which match revenues with gas costs and normally allow eventual full recovery of gas costs. Adjustments under these clauses require periodic filings and hearings with the relevant regulatory authority, but do not require a general rate proceeding. Rates on interruptible sales by the Florida division are also subject to purchased gas adjustment clauses.

Management monitors the rate of return in each jurisdiction in order to ensure the timely filing of rate adjustment applications.

Regulatory Proceedings

Maryland. During the month of March 1997, the Maryland Public Service Commission ("MPSC") approved an order authorizing Chesapeake to implement new service offerings and rate design for services rendered on and after April 1, 1997. The approved changes included: (1) class revenue requirements and restructured sales services which provide for separate firm commercial and industrial rate schedules for general service, medium volume, large volume and high load factor customer groups; (2) unbundling of gas costs from distribution charges; (3) a new gas cost recovery mechanism, which utilizes a projected period under which the fixed cost portion of the gas rate will be forecasted on an annual basis and the commodity cost portion of the gas rate will be estimated quarterly, based on projected market prices; and (4) a new sharing agreement under which interruptible margins will continue to be shared, 90% to customers and 10% to the Company, but distribution costs incurred for incremental load additions can be recovered with carrying charges utilizing 100% of the incremental margin if the payback period is within three years.

At the request of the MPSC Staff, consideration of the Company's proposed new transportation services was postponed until Eastern Shore Natural Gas Company's open access filing was settled with the FERC. As mentioned previously, Eastern Shore Natural Gas Company became an open access pipeline on November 1, 1997.

Chesapeake's Maryland division was involved in a roundtable collaborative process with the MPSC Staff, customer representatives, third party suppliers or marketers and the Maryland Office of People's Counsel during the last half of 1997 and the first half of 1998, developing initial transportation services for its commercial and industrial customers. The MPSC issued an order in July 1998 authorizing the Company to implement transportation and balancing services effective October 1, 1998 for commercial and industrial customers with annual consumption over 30,000 Ccf per year to transport customer-owned gas on the Company's distribution system.

Delaware. In September 1998, Chesapeake's Delaware division filed an application with the Delaware Public Service Commission ("DPSC") to propose certain rate design changes to its existing margin sharing mechanism which was approved in the Company's 1997 rate restructuring. Chesapeake filed this application as an alternative to a base rate proceeding in order to provide the Company an opportunity to earn its allowed rate of return, without increasing the price of its natural gas services from the Company's last rate case in 1995.

The Company proposed certain rate design changes to its currently existing margin sharing mechanism in order to address the level of recovery of fixed distribution costs from the residential heating service customers and smaller commercial heating customers. Chesapeake proposed to modify the existing margin sharing thresholds to address the actual level of fixed distribution cost recovered from the residential and smaller commercial customers based on the base tariff rates established in PSC Docket No. 95- 73, Phase II. Chesapeake's base tariff rates established in the last rate case were designed to recover a certain amount of fixed distribution costs in order for Chesapeake to earn its authorized rate of return. The proposal increases or decreases the current margin sharing thresholds based on the actual level of recovery of fixed distribution costs from these respective customer classes as compared to the level which the base tariff rates were designed to recover in the last rate case.

The Company also proposed to change the existing margin sharing mechanism to take into consideration the appropriate treatment of margins achieved by the addition of new interruptible customers on the distribution system for which the Company makes capital investments to serve these customers. Currently, Chesapeake is required to include in its margin sharing calculation the margins achieved from all of its interruptible customers. Chesapeake does not have the opportunity to earn a return on its capital investments until base tariff rates are established in the context of a base rate proceeding. The Company proposes to exclude from the margin sharing mechanism the margins achieved from the addition of new interruptible customers in order to provide the Company a reasonable opportunity to earn its authorized rate of return until the Company's next base rate proceeding.

During October 1998, the DPSC suspended the Company's tariff filing, pending the completion of full evidentiary hearing(s) and a final decision by the DPSC during 1999. During February 1999, the scheduled evidentiary hearing was convened to introduce the Company's testimony and exhibits, as well as DPSC Staff's testimony, into the record of evidence. The parties deferred any cross-examination in this docket until March 1999 when the hearing will reconvene. At this time, the Company and the respective parties are engaged in discussions in an effort to reach a settlement on the issues beneficial to all parties prior to the next scheduled hearing. If a settlement cannot be reached among the parties in this docket, then the hearing will reconvene in March 1999 and the issues will be determined based on a formal commission proceeding. The DPSC most likely would issue a final order in this docket during May or June 1999.

In February 1997, the DPSC approved an order authorizing Chesapeake to implement new service offerings and rate design for services rendered on and after March 1, 1997. The approved changes included: (1) restructured sales services which provided commercial and industrial customers with various service classifications such as general service, medium volume, large volume, and high load factor services; (2) a modified purchased gas cost recovery mechanism which takes into consideration the unbundling of gas costs from distribution charges as well as charging certain firm service classifications different gas cost rates based on the service classification's load factor; (3) the implementation of a mechanism for sharing interruptible, capacity release and off-system sales margins between firm sales customers and the Company, with changing margin sharing percentages based on the level of total margin achieved; and (4) a provision for transportation and balancing services for commercial and industrial customers with annual consumption over 30,000 Ccf per year to transport customer-owned gas on the Company's distribution system. The Company's Delaware division implemented these initial transportation and balancing services on December 1, 1997 as a result of its pipeline supplier, Eastern Shore Natural Gas Company, becoming an open access pipeline on November 1, 1997.

Florida. On August 7, 1998, the Florida Division filed an administrative request for approval to revise its tariff sheets to include Citrus County,

Florida in its service territory. On August 19, 1998, we received notification that the tariff sheets had been approved by the PSC Staff. The Company has executed service agreements with several customers in the area and is in the process of securing franchise agreements with the cities of Crystal River and Inverness. The Company's approved tariff sheets became effective on September 10, 1998.

On July 15, 1998, the Florida Division filed a petition seeking the authority to implement a flexible gas service tariff. This tariff is designed to meet the Company's need to compete for potential customers who have other viable energy options and to increase load by working with customers with regard to specific terms and conditions of service. Approval of this tariff would enable the Company to provide potential and existing customers with flexible pricing and contract terms which would be precluded under our existing tariff. On October 6, 1998, the Commission voted to approve our Flexible Gas Service tariff. The tariff became effective upon approval and is now available for use in negotiations with customers at the sole option of the Company.

On May 7, 1998, the Company filed for approval of two transportation agreements with Quincy Farms and Fernlea Nurseries. Both customers are located in Gadsden County, Florida. The agreements provide for a transportation rate equal to the non-fuel rate in existence prior to the rate restructuring for the first two years of each contract. The majority of our negotiations with these two customers took place prior to the rate restructuring proceeding. The Company also requested modification of its tariff sheets to include Gadsden County in its service territory. PSC Staff issued its recommendation supporting the petition on June 18, 1998. The Commission voted to approve the contracts and tariff sheet revisions on June 30, 1998.

On November 26, 1997, the Florida Division filed a request with the Florida Public Service Commission (FPSC) in Docket No. 971559-GU, for a Limited Proceeding to Restructure Rates and for Approval of Gas Transportation Agreements. The Florida Division has entered into Gas Transportation Contracts with its two largest customers which resulted in retaining these two customers on the Company's distribution system at rates lower than previously achieved. As a result of this reduction in non-fuel revenue, the Company has proposed in its application to restructure rates for its remaining customers to more closely reflect the cost of service for each rate class and to recover the level of revenues previously generated by the two Contract customers.

The Company's restructuring proposal is revenue neutral. Approval of this request would not result in additional revenues to the Company; however, FPSC approval would enable the Company to retain its two largest customers while providing the Company with the opportunity to achieve its FPSC authorized rate of return.

FPSC Staff issued their recommendation in this docket on March 12, 1998. The Commission voted to approve the Company's restructuring proposal on March 24, 1998. A Commission Order on this docket was issued on March 31, 1998.

(i) (c) Propane Distribution and Marketing General Chesapeake's propane distribution group consists of Sharp Energy, Inc. ("Sharp Energy"), a wholly owned subsidiary of Chesapeake, its wholly owned subsidiary, Sharpgas, Inc. ("Sharpgas") and Tri-County Gas Company, Inc. ("Tri-County") a wholly owned subsidiary of Chesapeake. The propane marketing group consists of Xeron, Inc. ("Xeron"), a wholly owned subsidiary of Chesapeake.

On May 30, 1998, Chesapeake acquired Xeron, a natural gas liquids trading company located in Houston, Texas. Xeron markets propane to a number of large independent and petrochemical companies, resellers, and southeastern retail propane companies.

On March 6, 1997, the Company acquired Tri-County, a family-owned and operated propane distribution business located in Salisbury and Pocomoke, Maryland. The combined operations of the Company and Tri-County served approximately 35,000 propane customers on the Delmarva Peninsula and delivered approximately 26 million retail and wholesale gallons of propane during 1998.

The propane distribution business is affected by many factors such as seasonality, the absence of price regulation and competition among local providers. The propane marketing business is affected by wholesale price volatility and the demand and supply of propane at a wholesale level.

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 gaseous at normal pressures, 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 energy. Propane is sold primarily in suburban and rural areas which are not served by natural gas pipelines. Demand is typically much higher in the winter months and is significantly affected by seasonal variations, particularly the relative severity of winter temperatures, because of its use in residential and commercial heating.

Adequacy of Resources

Sharp Energy and Tri-County purchase propane primarily from suppliers, including major domestic oil companies and independent producers of gas liquids and oil. Supplies of propane from these and other sources are readily available for purchase by the Company. Supply contracts generally include minimum (not subject to a take-or-pay premiums) and maximum purchase provisions.

Sharp Energy and Tri-County use trucks and railroad cars to transport propane from refineries, natural gas processing plants or pipeline terminals to the Company's bulk storage facilities. From these facilities, propane is delivered in portable cylinders or by "bobtail" trucks, owned

and operated by the Companies, to tanks located at the customer's premises.

Xeron has no physical storage facilities or equipment to transport propane; however, they contract for storage and pipeline capacity to facilitate the sale of propane on a wholesale basis.

Competition

Sharp Energy and Tri-County compete with several other propane distributors in their service territories, primarily on the basis of service and price, emphasizing reliability of service and responsiveness. Competition is generally local because distributors located in close proximity to customers incur lower costs of providing service. Propane competes with electricity as an energy source, because it is typically less expensive than electricity, based on equivalent BTU value. Since natural gas has historically been less expensive than propane, propane is generally not distributed in geographic areas serviced by natural gas pipeline or distribution systems.

Xeron competes against various marketers that may have significantly great resources and are able to obtain price or volumetric advantages over Xeron.

The Company's propane distribution and 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 under the Federal Motor Carrier Safety Act, which is administered by the United States Department of Transportation and enforced by the various states in which such operations take place. Propane distribution operations are also subject to state safety regulations relating to "hook-up" and placement of propane tanks.

The Company's propane operations are subject to all operating hazards normally associated with the handling, storage and transportation of combustible liquids, such as the risk of personal injury and property damage caused by fire. The Company carries general liability insurance in the amount of \$35,000,000 per occurrence, but there is no assurance that such insurance will be adequate.

(i) (d) Advanced Information Services General Chesapeake's advanced information services segment is comprised of United Systems, Inc. ("USI") and Capital Data Systems, Inc. ("CDS"), both wholly owned subsidiaries of the Company. CDS provided programming support for application software, until the first quarter of 1997, at which time it disposed of substantially all of its assets.

USI is an Atlanta-based company that primarily provides support for users of PROGRESST, a fourth generation computer language and Relational Database Management System. USI offers consulting, training, software development "tools", web development and customer software development for its client base, which includes many large domestic and international corporations.

Competition

The advanced information services businesses face significant competition from a number of larger competitors having substantially greater resources available to them than the Company. In addition, changes in the advanced information services businesses are occurring rapidly, which could adversely impact the markets for the Company's products and services.

(i) (e) Other Subsidiaries Skipjack, Inc. ("Skipjack") and Chesapeake Investment Company ("Chesapeake Investment"), are wholly owned subsidiaries of Chesapeake Service Company. Skipjack owns and leases two office buildings in Dover, Delaware to affiliates. Chesapeake Investment is a Delaware affiliated investment company.

On March 30, 1998, the Company acquired Sam Shannahan Well Co., based in Salisbury, Maryland, operating as Tolan Water Service ("Tolan"). Tolan was a privately owned company serving 3,000 customers on the Delmarva Peninsula with divisions supporting residential, commercial and industrial water treatment.

On March 6, 1997, in connection with the acquisition of Tri-County, the Company acquired Eastern Shore Real Estate, Inc. ("ESR"), which became a wholly owned subsidiary of Chesapeake Service Company. ESR owns and leases office buildings to affiliates and external companies.

(ii) Seasonal Nature of Business Revenues from the Company's residential and commercial natural gas sales and from its propane distribution activities are affected by seasonal variations, since the majority of these sales are to customers using the fuels for heating purposes. Revenues from these customers are accordingly affected by the mildness or severity of the heating season.

(iii) Capital Budget A discussion of capital expenditures by business segment is included in Item 7 under the heading "Management Discussion and Analysis - Liquidity and Capital Resources".

(iv) Employees Chesapeake has 456 employees, including 165 in natural gas distribution and transmission, 135 in propane distribution, 7 in propane marketing, 81 in advanced information services and 25 in water conditioning. The remaining 43 employees are considered general and administrative and include officers of the Company, treasury, accounting, information technology, human resources and other administrative personnel. The acquisition of Tolan Water Service added 25 employees, while the Xeron acquisition added 7 employees.

Item 2. Properties

(a) General The Company owns offices and operates facilities in the following locations:

Pocomoke, Salisbury, Cambridge, and Princess Anne, Maryland; Dover, Seaford, Laurel and Georgetown, Delaware; and Winter Haven, Florida. Chesapeake rents office space in Dover, Delaware; Plant City, Florida; Chincoteague and Belle Haven, Virginia; Easton and Pocomoke, Maryland; Detroit, Michigan; Houston, Texas and Atlanta, Georgia. In general, the properties of the Company are adequate for the uses for which they are employed. Capacity and utilization of the Company's facilities can vary significantly due to the seasonal nature of the natural gas and propane distribution businesses.

(b) Natural Gas Distribution Chesapeake owns over 576 miles of natural gas distribution mains (together with related service lines, meters and regulators) located in its Delaware and Maryland service areas, and 474 miles of such mains (and related equipment) in its Central Florida service areas. Chesapeake also owns facilities in Delaware and Maryland for propane-air injection during periods of peak demand. Portions of the properties constituting Chesapeake's distribution system are encumbered pursuant to Chesapeake's First Mortgage Bonds.

(c) Natural Gas Transmission Eastern Shore owns approximately 273 miles of transmission lines extending from Parkesburg, Pennsylvania to Salisbury, Maryland. Eastern Shore also owns three compressor stations located in Delaware City, Delaware; Daleville, Pennsylvania and Bridgeville, Delaware. The Delaware City compressor facility and associated piping are needed to stabilize capacity on Eastern Shore's system as a result of steadily declining inlet pressures at the Hockessin interconnect with Transco. The Daleville station is used to increase Columbia supply pressures to match Transco supply pressures, and to increase Eastern Shore's pressures in order to serve Eastern Shore's firm customers' demands, including those of Chesapeake's Delaware and Maryland divisions. The Bridgeville station is being used to provide increased pressures required to meet demands on the system.

(d) Propane Distribution and Marketing Sharpgas and Tri-County own bulk propane storage facilities with an aggregate capacity of approximately 1.9 million gallons at 32 plant facilities in Delaware, Maryland and Virginia, located on real estate they either own or lease. Xeron has no physical storage facilities or equipment to transport propane.

Item 3. Legal Proceedings

(a) General The Company and its subsidiaries are involved in certain legal actions and claims arising in the normal course of business. The Company is also involved in certain legal and administrative proceedings before various governmental agencies concerning rates. In the opinion of management, the ultimate disposition of these proceedings will not have a material effect on the consolidated financial position of the Company.

(b) Environmental Dover Gas Light Site In 1984, the State of Delaware notified the Company that a parcel of land it purchased in 1949 from Dover Gas Light Company, a predecessor gas company, contained hazardous substances. The State also asserted that the Company is responsible for any clean-up and prospective environmental monitoring of the site. The Delaware Department of Natural Resources and Environmental Control ("DNREC") investigated the site and surroundings, finding coal tar residue and some ground-water contamination.

In October 1989, the Environmental Protection Agency Region III ("EPA") listed the Dover site on the National Priorities List under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or "Superfund"). At that time under CERCLA, both the State of Delaware and the Company were named as potentially responsible parties ("PRPs") for clean-up of the site.

The EPA issued the site Record of Decision ("ROD") dated August 16, 1994. The remedial action selected by the EPA in the ROD addressed the ground-water contamination with a combination of hydraulic containment and natural attenuation. Remediation selected for the soil at the site was to meet stringent cleanup standards for the first two feet of soil and less stringent standards for the soil below two feet. The ROD estimated the costs of selected remediation of ground-water and soil at \$2.7 million and \$3.3 million, respectively.

In May 1995, EPA issued an order to the Company under section 106 of CERCLA (the "Order"), which required the Company to fund or implement the ROD. The Order was also issued to General Public Utilities Corporation, Inc. ("GPU"), which both EPA and the Company believe is liable under CERCLA. Other PRPs such as the State of Delaware were not ordered to perform the ROD. EPA may seek judicial enforcement of its Order, as well as significant financial penalties for failure to comply. Although notifying EPA of objections to the Order, the Company agreed to comply. GPU informed EPA that it did not intend to comply with the Order.

In March 1995, the Company commenced litigation against the State of Delaware for contribution to the remedial costs being incurred to carry out the ROD. In December of 1995, this case was dismissed without prejudice based on a settlement agreement between the parties (the "Settlement"). Under the Settlement, the State agreed to: support the Company's proposal to reduce the soil remedy for the site, described below; contribute \$600,000 toward the cost of implementing the ROD and reimburse the EPA for \$400,000 in oversight costs. The Settlement is contingent upon a formal settlement agreement between EPA and the State of Delaware. Upon satisfaction of all conditions of the Settlement, the litigation will be dismissed with prejudice.

In June 1996, the Company initiated litigation against GPU for contribution to the remedial costs incurred by Chesapeake in connection with complying with the ROD. At this time, management cannot predict the outcome of the litigation or the amount of proceeds to be received, if any.

In July 1996, the Company began the design phase of the ROD, on-site pre-design and investigation. A pre-design investigation report ("the report") was filed in October 1996 with the EPA. The report, which required EPA approval, provided up to date status on the site, which the EPA used to determine if the remedial design selected in the ROD was still the appropriate remedy.

In the report, the Company proposed a modification to the soil clean-up remedy selected in the ROD to take into account an existing land use restriction banning future development at the site. In April of 1997, the EPA issued a fact sheet stating that the EPA was considering the proposed modification. The fact sheet included an overall cost estimate of \$5.7 million for the proposed modified remedy and a new overall cost estimate of \$13.2 million for the remedy selected in the ROD. On August 28, 1997, the EPA issued a Proposed Plan to modify, with respect to soil remediation only, the current clean-up plan that would involve the following three elements: (1) excavation and off-site thermal treatment of the contents of the former subsurface gas holders; (2) implementation of soil vaporization extraction; and (3) pavement of the parking lot. The overall estimated clean-up cost of the site under the proposed plan was \$4.2 million (\$1.5 million for soil remediation and \$2.7 million for ground-water remediation) as compared to the ROD cleanup estimate of \$6.0 million (\$3.3 million for soil remediation and \$2.7 million for ground-water remediation). In January 1998, the EPA issued a ROD Amendment, which modified the soil remediation to conform to the proposed plan and included the estimated soil clean-up costs of \$4.2 million.

During the fourth quarter of 1998 the Company completed the first element of the soil remediation at the Dover site at a cost of \$450,000. Over the next twelve to eighteen months the Company will finalize the remaining two elements of the soil remediation and initiate the ground-water remedial activities.

The Company's independent consultants have prepared preliminary cost estimates of two potentially acceptable alternatives to complete the ground-water remediation activities at the site. The costs range from a low of \$390,000 in capital and \$37,000 per year of operating costs for 30 years for natural attenuation to a high of \$4.0 million in capital and \$500,000 per year in operating costs for 30 years for a pump and treat system. A decision by the EPA as to the most appropriate ground-water remediation method is likely in 1999. The capital costs necessary to begin ground-water remediation are expected to be incurred over the next twelve to eighteen months.

The Company cannot predict which ground-water remediation method will be selected by the EPA and accordingly, has accrued \$2.1 million at December 31, 1998 for the Dover site, as well as a regulatory asset for an equivalent amount. Of this amount, \$1.5 million is for ground-water remediation and \$600,000 is for the remaining soil remediation. The \$1.5 million represents the low end of the ground-water remedy estimates described above. As of December 31, 1997, the Company had accrued both a liability and a regulatory asset of \$4.2 million. The Company is currently engaged in investigations related to additional parties who may be PRPs. Based upon these investigations, the Company will consider suit against other PRPs. The Company expects continued negotiations with PRPs in an attempt to resolve these matters.

Management believes that in addition to the \$600,000 expected to be contributed by the State of Delaware under the Settlement, the Company will be equitably entitled to contribution from other responsible parties for a portion of the expenses to be incurred in connection with the remedies selected in the ROD. The Company expects that it will be able to recover actual costs incurred (exclusive of carrying costs), which are not recovered from other responsible parties, through the ratemaking process in accordance with the existing environmental cost recovery rider provisions described below.

As of December 31, 1998, the Company has incurred approximately \$6.6 million in costs relating to environmental testing and remedial action studies. In 1990, the Company entered into settlement agreements with a number of insurance companies resulting in proceeds to fund actual environmental costs incurred over a five to seven-year period. In 1995, the Delaware Public Service Commission, authorized recovery of all unrecovered environmental costs incurred by a means of a rider (supplement) to base rates, applicable to all firm service customers. The costs, exclusive of carrying costs, would be recovered through a five-year amortization offset by the deferred tax benefit associated with those environmental costs. The deferred tax benefit equals the projected cash flow savings realized by the Company in connection with a reduced income tax liability due to the possibility of accelerated deduction allowed on certain environmental costs when incurred. Each year a new rider rate is calculated to become effective December 1. The rider rate is based on the amortization of expenditures through September of the filing year plus amortization of expenses from previous years. The advantage of the rider is that it is not necessary to file a rate case every year to recover expenses incurred. As of December 31, 1998, the unamortized balance and amount of environmental costs not included in the rider, effective January 1, 1999 were \$2.5 million and \$679,000, respectively. With the rider mechanism established, it is management's opinion that these costs and any future cost, net of the deferred income tax benefit, will be recoverable in rates.

Salisbury Town Gas Light Site

In cooperation with the Maryland Department of the Environment ("MDE"), the Company completed assessment of the Salisbury manufactured gas plant site, determining that there was localized ground-water contamination. During 1996, the Company completed construction and began the Air Sparging and Soil-Vapor Extraction remediation procedures. Chesapeake has been reporting the remediation and monitoring results to the Maryland Department of the Environment on an ongoing basis since 1996.

The cost of remediation is estimated at \$136,000 per year for operating expenses for five years. Based on these estimated costs, the Company recorded both a liability and a deferred regulatory asset of \$600,000 on December 31, 1998, to cover the Company's projected remediation costs for this site. As of December 31, 1998, the Company has incurred approximately \$2.5 million for remedial actions and environmental

studies and has charged such costs to accumulated depreciation. In January 1990, the Company entered into settlement agreements with a number of insurance companies resulting in proceeds to fund actual environmental costs incurred over a three to five-year period beginning in 1990. The final insurance proceeds were requested and received in 1992. In December 1995, the Maryland Public Service Commission approved recovery of all environmental cost incurred through September 30, 1995 less amounts previously amortized and insurance proceeds. The amount approved for a 10-year amortization was \$964,251. Of the \$2.5 million in costs reported above, approximately \$770,000 has not been recovered through insurance proceeds or received ratemaking treatment. It is management's opinion that these costs incurred and future costs incurred, if any, will be recoverable in rates.

Winter Haven Coal Gas Site

In May 1996, the Company filed an Air Sparging and Soil Vapor Extraction Pilot Study Work Plan for the Winter Haven site with the Florida Department of Environmental Protection ("FDEP"). The Work Plan described the Company's proposal to undertake an Air Sparging and Soil Vapor Extraction ("AS/SVE") pilot study to evaluate at the site. After discussions with the FDEP, the Company filed a modified AS/SVE Pilot Study Work Plan, scope of work to complete the site assessment activities and a report describing a limited sediment investigation performed recently. The Company is awaiting FDEP's comments to the modified Work Plan. It is not possible to determine whether remedial action will be required by FDEP and, if so, the cost of such remediation.

The Company has spent and received ratemaking treatment of approximately \$697,000 on these investigations as of December 31, 1998. The Company has been allowed by the Florida Public Service Commission to continue to accrue for future environmental costs. At December 31, 1998, the Company had \$501,000 accrued. It is management's opinion that future costs, if any, will be recoverable in rates.

Item 4. Submission of Matters to a Vote of Security Holders

None

Item 10. Executive Officers of the Registrant

Information pertaining to the Executive Officers of the Company is as follows:

Ralph J. Adkins (age 56) Mr. Adkins is Chairman of the Board of Chesapeake. He has served as Chairman of the Board since August 1997. Previously, Mr. Adkins served as Chairman of the Board and Chief Executive Officer, President and Chief Executive Officer, President and Chief Operating Officer, Executive Vice President, Senior Vice President, Vice President and Treasurer of Chesapeake. Mr. Adkins is Chairman of Chesapeake Service Company, Sharp Energy, Inc., Tri-County Gas Company, Inc., Chesapeake Investment Company, Xeron, Inc., Sam Shannahan Well Co. and Eastern Shore Natural Gas Company, all wholly owned subsidiaries of Chesapeake. He has been a director of Chesapeake since 1989.

John R. Schimkaitis (age 51) Mr. Schimkaitis is President and Chief Executive Officer. He has served in this position since January 1, 1999. Mr. Schimkaitis is also Chief Executive Officer of Chesapeake Service Company, Sharp Energy, Inc., Tri-County Gas Company, Chesapeake Investment Company, Xeron, Inc., Sam Shannahan Well Co. and Eastern Shore Natural Gas Company, all wholly owned subsidiaries of Chesapeake. He previously served as President and Chief Operating Officer, Executive Vice President, Chief Financial Officer, Senior Vice President, Treasurer and Assistant Secretary. From 1983 to 1986, Mr. Schimkaitis was Vice President of Cooper & Rutter, Inc., a consulting firm providing financial services to the utility and cable industries. He was appointed as a director of Chesapeake in February 1996.

Michael P. McMasters (age 40) Mr. McMasters is Vice President, Chief Financial Officer and Treasurer of Chesapeake Utilities Corporation. He has served as Vice President, Chief Financial Officer and Treasurer since December 1996. He previously served as Vice President of Eastern Shore, 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.

Stephen C. Thompson (age 38) Mr. Thompson is Vice President of the Natural Gas Operations, as well as Vice President of Chesapeake Utilities Corporation. He has served as Vice President since May 1997. He has served as President, Vice President, Manager, Director of Gas Supply and Marketing, Superintendent of Eastern Shore and Regional Manager for the Florida distribution Operations.

Philip S. Barefoot (age 51) Mr. Barefoot joined Chesapeake as Division Manager of Florida Operations in July 1988. In May 1994, he was elected Vice President of Chesapeake Utilities Corporation. Prior to joining Chesapeake, he was employed by Peoples Natural Gas Company where he held the positions of Division Sales Manager, Division Manager and Vice President of Florence Operations.

PART II

Item 5. Market for the Registrant's Common Stock and Related Security Holder

Matters

(a) Common Stock Price Ranges, Common Stock Dividends and Shareholder Information:

The Company's Common Stock is listed on the New York Stock Exchange under the symbol "CPK". The high, low and closing prices of Chesapeake's Common Stock and dividends declared per share for each calendar quarter during the years 1998 and 1997 were as follows:

Quarter Ended	High	Low	Close	Dividends Declared Per Share

1998				
March 31	\$20.500	\$18.250	\$18.375	\$0.2500
June 30	18.500	17.125	17.625	0.2500
September 30	18.500	16.500	17.938	0.2500
December 31	18.500	17.000	18.938	0.2500

1997				
March 31	\$18.000	\$16.500	\$17.375	\$0.2425
June 30	17.500	16.000	17.000	0.2425
September 30	18.500	16.250	18.375	0.2425
December 31	21.750	18.375	20.500	0.2425

In addition to the dividends declared by the Company, Xeron paid total dividends of \$27,000 during 1998.

Indentures to the long-term debt of the Company and its subsidiaries contain a restriction that the Company cannot, until the retirement of its Series I Bonds, pay any dividends after December 31, 1988 which exceed the sum of \$2,135,188 plus consolidated net income recognized on or after January 1, 1989. As of December 31, 1998, the amounts available for future dividends permitted by the Series I covenant are \$14.7 million.

At December 31, 1998, there were approximately 2,271 shareholders of record.

(b) Issuance of shares:

On May 29, 1998, in conjunction with the acquisition of Xeron, Inc., the Company issued 475,000 shares of common stock to J. Phillip Keeter, Earnest Allen Jr. and Patrick E. Armand in reliance on the private placement exemption provided by Section 4(c) of the Securities Act of 1933 and Regulation D, thereunder. On March 31, 1998, in conjunction with the acquisition of Sam Shannahan Well Co., the Company issued 25,000 shares of company stock to Deshield J. Shannahan and Joyce C. Shannahan in reliance on the private placement exemption provided by Section 4(c) of the Securities Act of 1933 and Regulation D, thereunder.

Item 6. Selected Financial Data

For the Years Ended December 31,	(dollars in thousands except stock data)				
	1998	1997	1996	1995	1994 (1)
Operating					
Operating revenues	\$183,569	\$222,489	\$260,102	\$235,285	\$ 98,572
Operating income	\$ 8,441	\$ 8,666	\$ 10,099	\$ 9,962	\$ 7,227
Net income	\$ 5,303	\$ 5,868	\$ 7,782	\$ 7,696	\$ 4,460
Balance Sheet					
Gross plant	\$152,991	\$144,251	\$134,001	\$120,746	\$110,023
Net plant	\$104,266	\$ 99,879	\$ 94,014	\$ 85,055	\$ 75,313
Total assets	\$145,234	\$145,719	\$155,786	\$130,998	\$108,271
Long-term debt, net	\$ 37,597	\$ 38,226	\$ 28,984	\$ 31,619	\$ 24,329
Common stockholders' equity	\$ 56,356	\$ 53,656	\$ 50,699	\$ 45,587	\$ 37,063
Capital expenditures	\$ 12,650	\$ 13,471	\$ 15,399	\$ 12,887	\$ 10,653
Common Stock					
Earnings per share:					
Basic	\$ 1.05	\$ 1.18	\$ 1.58	\$ 1.59	\$ 1.23
Diluted	\$ 1.04	\$ 1.17	\$ 1.55	\$ 1.56	\$ 1.20
Average shares outstanding	5,060,328	4,972,086	4,912,136	4,836,430	3,628,056
Cash dividends per share	\$ 1.00	\$ 0.97	\$ 0.93	\$ 0.90	\$ 0.88
Book value per share	\$ 11.06	\$ 10.72	\$ 10.26	\$ 9.38	\$ 10.15
Common equity/Total capitalization	59.98%	58.40%	63.63%	59.05%	60.37%
Return on equity	9.41%	10.94%	15.35%	16.88%	12.03%
Other					
Number of employees	456	429	418	415	320
Number of registered shareholders	2,271	2,178	2,213	2,098	1,721
Heating degree days	3,704	4,430	4,717	4,594	4,398
Heating degree days (10-year average)	4,579	4,596	4,586	4,564	4,588

(1) 1994 has not been restated to include the business combinations with Tri-County Gas Company, Inc., Tolan Water Service or Xeron, Inc.

[GRAPH APPEARS HERE]

Growth in Book Value
Compared to Dividend Growth

Dividends	Book	
Year	Value	Per
Share		
-----	-----	
1994	\$10.15	\$0.88
1995	\$9.37	\$0.90
1996	\$10.26	\$0.93
1997	\$10.72	\$0.97
1998	\$11.06	\$1.00

[GRAPH APPEARS HERE]

Earnings Compared to Heating
Degree Days

Heating		Degree
Year	Earnings	Days
-----	-----	
1994	\$1.23	4,398
1995	\$1.59	4,594
1996	\$1.58	4,717
1997	\$1.18	4,430
1998	\$1.05	3,704

Item 7. Management's Discussion and Analysis of Financial Condition and

Results of Operations

Liquidity and Capital Resources

The capital requirements of Chesapeake Utilities Corporation ("Chesapeake" or "the Company") reflect the capital-intensive nature of its business and are attributable principally to the construction program and the retirement of outstanding debt. The Company relies on cash generated from operations and short-term borrowing to meet normal working capital requirements and temporarily finance capital expenditures. During 1998, net cash provided by operating activities was \$11.0 million, cash used by investing activities was \$12.5 million and cash used by financing activities was \$737,000.

The Board of Directors has authorized the Company to borrow up to \$20.0 million from various banks and trust companies. As of December 31, 1998, Chesapeake had three unsecured bank lines of credit, totaling \$28.0 million, for short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of its capital expenditures. The outstanding balances of short-term borrowing at December 31, 1998 and 1997 were \$11.6 million and \$7.6 million, respectively.

In 1998, Chesapeake used cash provided by operations and short-term borrowing to fund capital expenditures. During 1997, the Company used cash provided by operations and the issuance of long-term debt to fund capital expenditures and reduce short-term borrowing.

During 1998, 1997 and 1996, capital expenditures were approximately \$12.0 million, \$12.4 million and \$14.0 million, respectively. Chesapeake has budgeted \$22.7 million for capital expenditures during 1999. This amount includes \$10.5 million and \$8.6 million for natural gas distribution and transmission, respectively, \$1.8 million for propane distribution and marketing, \$336,000 for advanced information services and \$1.5 million for general plant. The natural gas distribution expenditures are for expansion and improvement of facilities in existing service territories. Natural gas transmission expenditures are for improvement and expansion of the pipeline system, specifically, the construction of eight miles of pipeline to provide additional firm transportation capacity to two existing customers. The propane expenditures are to support customer growth and the replacement of older equipment. The advanced information services expenditures are for computer hardware, software and related equipment. General expenditures are for building improvements, computer software and hardware. Financing

for the 1999 construction program is expected to be provided from short-term borrowing and cash from operations. The construction program is subject to continuous review and modification. Actual construction expenditures may vary from the above estimates due to a number of factors including acquisition opportunities, changing economic conditions, customer growth in existing areas, regulation and new growth opportunities.

Chesapeake has budgeted \$2.2 million for environmental related expenditures during 1999 and expects to incur additional expenditures in future years, a portion of which may need to be financed through external sources (see Note L to the Consolidated Financial Statements). Management does not expect such financing to have a material adverse effect on the financial position or capital resources of the Company.

Capital Structure

As of December 31, 1998, common equity represented 60.0% of permanent capitalization, compared to 58.4% in 1997 and 63.6% in 1996. Chesapeake remains committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access the capital markets when required. This commitment, along with adequate and timely rate relief for the Company's regulated operations, helps to ensure that Chesapeake will be able to attract capital from outside sources at a reasonable cost. The achievement of these objectives will provide benefits to customers and creditors, as well as to the Company's investors.

Financing Activities

On March 31, 1998, Chesapeake acquired Sam Shannahan Well Co., Inc., operating as Tolan Water Service ("Tolan" or "Tolan Water") in exchange for 25,000 shares of Chesapeake's common stock. Tolan provides water conditioning services to approximately 3,000 residential, commercial and industrial customers on the Delmarva Peninsula.

All of the outstanding common stock of Xeron, Inc. ("Xeron") was acquired by Chesapeake on May 29, 1998. Xeron markets propane to a number of large independent oil and petrochemical companies, resellers, and southeastern retail propane companies. Four hundred seventy-five thousand shares of the Company's common stock were exchanged in the transaction.

On March 6, 1997, the Company acquired all of the outstanding common stock of Tri-County Gas Company, Inc. ("Tri-County") and associated properties. Tri-County distributes propane to both retail and wholesale customers on the Delmarva Peninsula. The transaction was effected through the exchange of 639,000 shares of the Company's common stock.

Each of these business combinations was accounted for as a pooling of interests.

During 1998, Chesapeake repaid approximately \$1.1 million of long-term debt. In December 1997, Chesapeake finalized a private placement of \$10 million of 6.85% Senior Notes due January 1, 2012. Debt repayments during 1997 totaled \$3.1 million. In 1996, Chesapeake repaid \$881,000 in long-term debt.

Chesapeake issued 32,925, 32,169 and 33,926 shares of common stock in connection with its Automatic Dividend Reinvestment and Stock Purchase Plan during the years of 1998, 1997 and 1996, respectively.

Results of Operations

Net income for 1998 was \$5.3 million as compared to \$5.9 million for 1997 and \$7.8 million for 1996. The decrease in net income is primarily related to warmer temperatures in the Company's northern service territory, partially offset by a one-time reduction in pension costs of \$1.2 million resulting from Chesapeake's 1998 restructuring of the Company's retirement benefits plans. Temperatures in 1998, based upon heating degree days, were 19% warmer than normal, 16% warmer than 1997 and 21% warmer than 1996. Temperatures in 1997 were approximately 6% warmer than those experienced in 1996. Normal weather conditions are calculated from the most recent ten years of temperature data measured in heating degree days. The warmer weather resulted in a reduction in volumes sold by both the natural gas distribution and propane segments. The lower volumes contributed to the reduction in Earnings Before Interest and Taxes ("EBIT") for both segments as shown in the table below.

EARNINGS BEFORE INTEREST AND TAXES (in thousands):

For the Years Ended December 31,	1998	1997	Increase (decrease)	1997	1996	Increase (decrease)
EBIT by Business Segment:						
Natural gas distribution	\$ 4,697	\$ 5,498	\$ (801)	\$ 5,498	\$ 7,167	\$(1,669)
Natural gas transmission	4,117	3,721	396	3,721	2,458	1,263
Propane distribution and marketing	971	1,158	(187)	1,158	2,669	(1,511)
Advanced information services	1,316	1,046	270	1,046	1,056	(10)
Other	522	671	(149)	671	633	38
Total EBIT	\$11,623	\$12,094	\$ (471)	\$12,094	\$13,983	\$(1,889)

Natural Gas Distribution

The \$801,000 reduction in EBIT from 1997 to 1998 was primarily the result of a reduction in gross margin, as indicated in the following table. Exclusive of the expense reductions related to the restructuring of the Company's retirement benefits plans, the decrease in EBIT of \$1.5 million or 27% was attributable to warmer than normal weather conditions. The reduction in gross margin of \$832,000 from the prior year is primarily due to the negative impact of warmer temperatures on volumes sold, partially offset by customer growth during the year. After taking into account customer growth of 4% for residential and commercial customers in the northern service territory, overall volumes declined by 12% for these customer classifications. Under normal temperatures and customer usage, the 4% customer growth is estimated to generate an additional margin of \$550,000 annually within this segment. Also contributing to the decline in margin is an 11% reduction in volumes sold and transported to industrial customers in the Florida service territory. Although operating expenses remained relatively unchanged, specific expense categories such as marketing, building rent, legal costs and depreciation and amortization increased. These were offset by decreases in pension expense, administrative fees associated with the pension plan, compensation and outside services.

The reduction in EBIT of \$1.7 million from 1996 to 1997 is primarily related to a decline in total gross margin, as indicated in the following table, coupled with an overall increase in expenses. The reduction in gross margin is primarily the result of a 4% decline in volumes sold to residential and commercial customers and a 5% decrease in volumes sold and transported to industrial customers in Chesapeake's Florida service territory. The reduction in volumes sold to residential and commercial customers was directly related to warmer temperatures, primarily during the first quarter of 1997. Operating expenses increased \$996,000 due to increases in compensation, regulatory commission expenses, and costs related to data processing and billable service revenue. In addition, there was a greater level of maintenance to the gas pipeline system and increased depreciation and amortization due to additional plant being placed in service.

NATURAL GAS DISTRIBUTION GROSS MARGIN SUMMARY (in thousands)

For the Years Ended December 31,	1998	1997	Increase (decrease)	1997	1996	Increase (decrease)
Revenues:						
Gas sold	\$50,466	\$54,205	\$ (3,739)	\$54,205	\$52,290	\$ 1,915
Gas transported	2,875	3,061	(186)	3,061	2,991	70
Gas marketed	11,683	18,419	(6,736)	18,419	19,382	(963)
Other	401	275	126	275	193	82
Total Revenues	\$65,425	\$75,960	\$ (10,535)	\$75,960	\$74,856	\$ 1,104
Cost of Sales: *						
Gas sold	\$32,529	\$35,507	\$ (2,978)	\$35,507	\$32,846	\$ 2,661
Gas marketed	11,508	18,233	(6,725)	18,233	19,117	(884)
Total Cost of Sales	\$44,037	\$53,740	\$ (9,703)	\$53,740	\$51,963	\$ 1,777
Gross Margin:						
Gas sold	\$17,937	\$18,698	\$ (761)	\$18,698	\$19,444	\$ (746)
Gas transported	2,875	3,061	(186)	3,061	2,991	70
Gas marketed	175	186	(11)	186	265	(79)
Other	401	275	126	275	193	82
Total Gross Margin	\$21,388	\$22,220	\$ (832)	\$22,220	\$22,893	\$ (673)

* Transportation service does not have an associated cost of sales.

Natural Gas Transmission

The Earnings Before Interest and Taxes of the Company's natural gas transmission segment increased \$396,000 from 1997 to 1998. This was the result of an increase in gross margin of \$468,000 offset by an \$87,000 increase in operating expenses. Exclusive of the expense reduction related to the restructuring of the Company's retirement benefits plans, EBIT increased \$221,000 or 6%. Gross margin increased under a full year of open access pipeline operations, as well as the full year's effect of both a rate increase and the implementation of new services which were both effective in 1997. Operating expenses were higher due to increases in regulatory commission expenses, legal fees, pipeline system maintenance and depreciation. These costs were offset by declines in pension costs, compensation and administrative fees associated with the pension plan.

The transmission segment's EBIT increased \$1.3 million from 1996 to 1997. The rise in EBIT was partially attributable to a rate increase and an increase in firm services implemented in 1997, as well as an overall reduction in expenses. Also contributing to the increase in EBIT were additional revenues generated by the increase in transportation services that were effective with the implementation of open access. Operating expenses decreased by \$124,000 or 3%, primarily due to reduced compensation, relocation costs, property insurance and pipeline system maintenance. These reductions were offset by higher depreciation expenses generated by capital additions during the year.

Propane Distribution and Marketing

In May 1998, the Company acquired Xeron, Inc., a wholesale marketer of propane, expanding Chesapeake's propane operations (see Note B to the Consolidated Financial Statements). The EBIT contribution of the propane distribution and marketing segment declined by \$187,000 from 1997 to 1998 due to a decrease in gross margin which was partially offset by a decline in operating expenses. Exclusive of the expense reduction related to the restructuring of the Company's retirement benefits plans, EBIT decreased \$463,000 or 40%. The propane distribution operation was negatively affected by the warmer temperatures realized in 1998, resulting in a decline in sales volumes of 8%, after taking into account a 3% increase in customer growth. Somewhat offsetting this volume-related decline in margin was an increase of 6% in the margin earned per gallon delivered as compared to the prior year. In addition, the lack of volatility in the wholesale propane market resulted in a reduction to propane marketing margins due to fewer gallons being marketed. Wholesale marketing is a high volume, low margin business. During 1998, marketing revenues declined by \$18.1 million or 18% while margins declined by \$250,000 or 16%. Operating expenses declined primarily due to compensation linked to Xeron's earnings, pension expense and administrative fees associated with the pension plan.

The Company estimates that the warm temperatures experienced in 1998 reduced EBIT by \$1.9 million when compared to normal temperatures. In addition, margins during 1998 were lower than historical norms, further reducing EBIT by approximately \$1.6 million.

The reduction in EBIT of \$1.5 million from 1996 to 1997 was primarily due to a reduction in gross margin earned by the distribution operation, partially offset by a reduction in operating expenses. Distribution margins decreased due to a 14% reduction in sales volumes coupled with a 13% lower margin per gallon sold. The decline in sales volumes is directly related to the warmer temperatures which averaged 6% warmer than those experienced in 1996. Furthermore, during the first quarter of 1997, temperatures were 14% warmer than normal. The marketing operation

contributed an additional \$240,000 to EBIT due to a reduction in compensation expense.

Advanced Information Services

The results of the advanced information services segment consisted primarily of those of United Systems, Inc. ("USI"). Exclusive of the expense reductions related to the restructuring of the Company's retirement benefits plans, EBIT contributed by USI increased 15% or \$156,000 from 1997 to 1998. Due to increased opportunities in areas such as website development, training and consulting, gross margin increased 38%, or \$1.5 million from 1997 to 1998.

Although the EBIT contribution of this segment remained virtually unchanged from 1996 to 1997, USI's gross margin increased by \$970,000 or 34%. Operating expenses increased due to the opening of a new office in Detroit, Michigan and the expansion of staff training and marketing efforts to position USI to be able to provide new services and for future growth of current services. Since the rise in operating costs offset most of the growth in gross margin, EBIT remained constant.

Income Taxes

Operating income taxes decreased \$245,000 in 1998 due to the reduction in EBIT. Income taxes also decreased in 1997 due to the reduction in EBIT. This was partially offset by a one-time expense to establish the deferred income tax liability in connection with the 1997 acquisition of Tri-County. The 1996 financial statements do not include any income tax expense for the acquisition due to its subchapter S status during that year.

Other

Non-operating income was \$241,000, \$545,000 and \$688,000 for the years 1998, 1997 and 1996, respectively. The decrease in 1998 is primarily attributable to one-time pre-tax gains of \$452,000 and \$300,000 on the sale of fixed assets included in 1997 and 1996, respectively. Also contributing to the 1998 decline is a reduction in interest income from \$288,000 for 1997 to \$188,000 for 1998.

Environmental Matters

The Company continues to work with federal and state environmental agencies to assess the environmental impact and explore corrective action at several former gas manufacturing plant sites (see Note L to the Consolidated Financial Statements). The Company believes that future costs associated with these sites will be recoverable in rates.

Market Risk

Market risk represents the potential loss arising from adverse changes in market rates and prices. The Company's long-term debt consists of first mortgage bonds, senior notes and convertible debentures (see Note G to the Consolidated Financial Statements for annual maturities of consolidated long-term debt). All of Chesapeake's long-term debt is fixed rate debt and was not entered into for trading purposes. The carrying value of the Company's long-term debt was \$38.1 million at December 31, 1998. The fair value was \$41.6 million at December 31, 1998, based mainly on current market prices or discounted cash flows using current rates for similar issues with similar terms and remaining maturities. The Company is exposed to changes in interest rates as a result of financing through its issuance of fixed rate long-term debt. The Company evaluates whether to refinance existing debt or permanently finance existing short-term borrowing based on the fluctuation in interest rates.

At December 31, 1998, the wholesale propane marketing operation was a party to natural gas liquids ("NGL") forward contracts, primarily propane contracts, with various third parties. These contracts require that the wholesale propane marketing operation purchase or sell NGL at a fixed price at fixed future dates. At expiration, the contracts are settled by the delivery of NGL to the respective party. The wholesale propane 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 of a net amount equal to the difference between the current market price of the futures contract and the original contract price.

The forward and futures contracts are entered into for trading and wholesale marketing purposes. The wholesale propane marketing operation is subject to commodity price risk on their open positions to the extent that NGL market prices deviate from fixed contract settlement amounts. Market risks associated with the trading of futures and forward contracts are monitored daily for compliance with Chesapeake's Risk Management Policy, which includes volumetric limits for open positions. In order to manage exposures to changing market prices, open positions are marked to market and reviewed by oversight officials on a daily basis. Additionally, the Risk Management Committee reviews periodic reports on market and credit risk, approves any exceptions to the Risk Management policy (within the limits established by the Board of Directors) and authorizes the use of any new types of contracts. Listed below is quantitative information on the forward and futures contracts at December 31, 1998. All of the contracts mature during 1999.

At December 31, 1998	Quantity in gallons	Estimated Market Prices	Weighted Average Contract Prices
Forward Contracts			
Sale	20,647,200	\$.2125 - \$.2550	\$0.2569
Purchase	24,263,400	\$.2125 - \$.2550	\$0.2424
Futures Contracts			
Sale	4,200,000	\$.2125 - \$.2550	\$0.2194
Purchase	714,000	\$.2125 - \$.2550	\$0.2110

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

The Year 2000

Chesapeake is dependent upon a variety of information systems to operate efficiently and effectively. In order to address the impact of the Year 2000 ("Year 2000" or "Y2K") on its information systems, Chesapeake is in the process of evaluating and remediating any deficiencies. The Company's evaluation of its readiness and the potential impact of the Year 2000 on its systems have been separated into five components: primary internal applications, embedded systems, vendors/suppliers, end-user computing systems and customers.

- Chesapeake's primary internal applications include company maintained software systems for its financial information; natural gas customer information and billing; and propane customer information, billing and delivery. The Company completed testing of these three applications in 1998 and deems them Year 2000 ready.

- Embedded systems include the supervisory control and data acquisition ("SCADA") system for the natural gas transmission segment, telecommunications, metering and other facilities related systems. Chesapeake has currently identified 64 vendors that support the Company's embedded systems. Chesapeake expects to finalize the review for additional vendors and/or embedded systems by the end of the first quarter of 1999. The Company has prioritized these vendors into three potential impact classifications: 15 high impact vendors, supporting items such as the SCADA system; 19 medium impact vendors, supporting systems such as telecommunications; and 30 low impact vendors, supporting items such as copiers and postage meters. The Company has been testing these systems and has contacted all of the vendors currently identified, with 85% responding. Of the vendors contacted, a total of 20 vendors - four high impact, six medium impact and ten low impact vendors - indicated they were Y2K ready. The Company has been either working with vendors to reach a state of readiness with the applicable systems or has changed to vendors or systems that are Y2K ready. The SCADA system, the most critical embedded system, is scheduled to be Y2K ready during the second quarter of 1999. Chesapeake will continue to follow up with vendors that are not Y2K ready and will consider alternate providers as necessary to the extent available.

- Chesapeake has identified 101 vendors/suppliers that supply the Company with products and services that impact various elements of the Company's business. The Company has classified these vendors into three impact classifications: 27 high impact vendors such as suppliers of natural gas or propane; 31 medium impact vendors such as regional communication vendors; and 43 low impact vendors. The Company has requested a Y2K status statement from each of these vendors. The Company has received 72 responses, which indicated that nine medium impact and 13 low impact vendors were Y2K ready. The Company will continue to follow up with vendors that are not Y2K ready and will consider alternate providers as necessary to the extent available.

- End-user computing systems are upgraded periodically through the Company's ongoing replacement program. Almost all of the Company's personal computers are currently Year 2000 ready. Additional personal computers will be replaced during the first quarter of 1999. Chesapeake's local area network is Year 2000 ready as is all PC-based and network-based software.

- Customers, primarily industrial interruptible natural gas customers, must ensure that their plant controls are Year 2000 ready for their alternative fuel. The Company has identified 107 interruptible customers and will contact each of them by the end of the first quarter of 1999. The Company will take into account the results of the survey in developing the natural gas contingency plan.

The Company believes the most significant potential risks with respect to its internal operations, those over which it has direct control, are its ability to: (1) use electronic devices to control and operate its natural gas delivery systems; (2) maintain continuous operation of its computer systems; (3) render timely bills to its customers; and (4) enforce tariffs and contracts applicable to interruptible customers.

The Company relies on the producers of natural gas and suppliers of interstate transportation capacity to deliver natural gas to the Company's

natural gas delivery systems. The Company is also dependent on propane producers, suppliers and railroad facilities to receive propane supply. Chesapeake is also dependent on various suppliers of communication services. Should any of these critical vendors fail, the impact of any such failure could become a significant challenge to the Company's ability to meet the demands of its customers, to operate its delivery systems and to communicate with its customers. It could also have a material adverse financial impact, including but not limited to, lost sales revenues, increased operating costs and claims from customers related to business interruptions. The Company's Year 2000 evaluation process is addressing each of these risks and the required remediation. The Company is developing its contingency plan for the Year 2000, which will address various alternatives and will include assessing a variety of scenarios that could emerge and require the Company to react. Chesapeake expects to have its contingency plan finalized by the end of the second quarter of 1999. The contingency plan will continue to be modified as warranted by changing events.

The costs incurred as of December 31, 1998 in addressing Year 2000 issues have been immaterial. The Company has estimated costs of \$270,000 to replace and/or remediate specific embedded systems. However, until the Company has completed further analysis of the impact of the Year 2000 issue on its embedded systems, vendors/suppliers, end-user computing systems, customers and contingency planning; it is unable to estimate any additional costs it may incur as a result of its efforts.

Presently, no Year 2000-impacted internal applications or embedded systems have been identified that cannot be upgraded or modified within acceptable time frames. The target date for completion of all Year 2000-related activities remains at mid-1999.

Competition

Historically, the Company's natural gas operations have successfully competed with other forms of energy such as electricity, oil and propane. The principal considerations have been price, and to a lesser extent, accessibility. As a result of Eastern Shore's recent conversion to open access, the Company expects to be subject to competitive pressures from other sellers of natural gas. With open access transportation services available on Eastern Shore's system, third party suppliers will compete with Chesapeake to sell gas to the local distribution companies and the end-users on Eastern Shore's system. Eastern Shore has shifted from providing sales service to providing transportation and contract storage services.

The Company's natural gas distribution operation located in Maryland began to offer transportation services to certain industrial customers during 1998. During 1997, the distribution operation located in Delaware also began offering transportation services. The Company expects to expand the availability of transportation services to additional customers in the future. The Florida distribution operation has been open to certain industrial customers since 1994. The Company established a natural gas brokering and supply operation in Florida to compete for these customers.

Both the propane and advanced information services businesses face significant competition from a number of larger competitors with substantially greater resources available to them than those of the Company. In addition, in the advanced information services business, changes are occurring rapidly which could adversely affect the markets for the Company's services.

Inflation

Inflation affects the cost of labor and other goods and services required for operation, maintenance and capital improvements. While the impact of inflation has lessened in recent years, natural gas prices are subject to rapid fluctuations. These fluctuations are passed on to customers through the gas cost recovery mechanism in the Company's tariffs. To help cope with the effects of inflation on its capital investments and returns, the Company seeks rate relief from regulatory commissions for regulated operations while monitoring the returns of its unregulated business operations.

Cautionary Statement

We make statements in this report that are considered forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are not matters of historical fact. Sometimes they contain words such as "believes," "expects," "intends," "plans," "will," or "may," and other similar words. These statements relate to such topics as customer growth, increases in revenues or margins, Year 2000 readiness, regulatory approvals, market risk associated with the Company's new propane marketing operation, the competitive position of the Company and other matters. It is important to understand that these forward-looking statements are not guarantees, but are subject to certain risks and uncertainties and other important factors that could cause actual results to differ materially from those in the forward-looking statements. These factors include, among other things:

- the seasonality and temperature sensitivity of Chesapeake's natural gas and propane businesses (that is, the Company's earnings vary depending on the season and, in the winter months, how cold the weather is);
- consumption patterns of the Company's existing and expected customers in these businesses;
- the wholesale price of propane and market movements in these prices, which affect both the margins in the Company's propane business and the profitability of the propane marketing operation;
- the relative price of alternative energy sources, to which some of Chesapeake's customers have access;

- the effects of competition on both unregulated and regulated businesses;
- the ability of the transmission segment to attract new customers in an open access environment;
- the ability of the Company's new and planned facilities to generate expected revenues;
- the Company's ability to obtain the rate relief requested from utility regulators and the timing of that rate relief; and
- the Company's ability to identify and address Year 2000 issues successfully, in a timely manner and at a reasonable cost, as well as the ability of the Company's vendors, suppliers, and other service providers and customers to successfully address their own Year 2000 issues in a timely manner.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk.

Information related to 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 Supplemental Data

REPORT OF INDEPENDENT ACCOUNTANTS

To the Stockholders of Chesapeake Utilities Corporation

In our opinion, the consolidated financial statements listed in the index appearing under item 14(a)(1) of this Form 10-K present fairly, in all material respects, the financial position of Chesapeake Utilities Corporation and its subsidiaries at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

In addition, in our opinion, the consolidated financial statement schedule listed in the index appearing under item 14(a)(2) of this Form 10-K presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP
Washington, D.C.
February 12, 1999

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	1998	1997	1996
Operating Revenues	\$ 183,568,795	\$ 222,489,264	\$ 260,102,200
Cost of Sales	136,019,813	175,191,090	207,655,979
Gross Margin	47,548,982	47,298,174	52,446,221
Operating Expenses			
Operations	23,669,514	23,686,774	26,485,013
Maintenance	2,123,456	2,068,114	2,550,197
Depreciation and amortization	6,109,202	5,475,417	5,605,930
Other taxes	4,024,129	3,974,097	3,822,200
Income taxes	3,181,599	3,427,308	3,884,377
Total operating expenses	39,107,900	38,631,710	42,347,717
Operating Income	8,441,082	8,666,464	10,098,504
Other Income			
Interest income	188,394	288,339	248,632
Other income, net	97,005	533,704	642,238
Income taxes	(44,145)	(276,888)	(202,239)
Total other income	241,254	545,155	688,631
Income Before Interest Charges	8,682,336	9,211,619	10,787,135
Interest Charges			
Interest on long-term debt	2,966,043	2,387,641	2,434,321
Amortization of debt expense	123,335	119,401	120,345
Other	290,372	836,965	450,536
Total interest charges	3,379,750	3,344,007	3,005,202
Net Income	\$ 5,302,586	\$ 5,867,612	\$ 7,781,933
Earnings Per Share of Common Stock :			
Basic	\$ 1.05	\$ 1.18	\$ 1.58
Diluted	\$ 1.04	\$ 1.17	\$ 1.55

Consolidated Statements of Comprehensive Income

For the Years Ended December 31,	1998	1997	1996
Net Income	\$ 5,302,586	\$ 5,867,612	\$ 7,781,933
Unrealized gain on marketable securities, net of income taxes	566,472	258,274	111,437
Total Comprehensive Income	\$ 5,869,058	\$ 6,125,886	\$ 7,893,370

See accompanying notes

CONSOLIDATED BALANCE SHEETS

Assets

At December 31,	1998	1997
Property, Plant and Equipment		
Natural gas distribution	\$ 81,844,066	\$ 75,564,462
Natural gas transmission	35,388,440	33,856,873
Propane distribution and marketing	27,287,807	27,091,102
Advanced information services	1,087,910	841,757
Other plant	7,382,965	6,896,899
Total property, plant and equipment	152,991,188	144,251,093
Less: Accumulated depreciation and amortization	(48,725,412)	(44,371,890)
Net property, plant and equipment	104,265,776	99,879,203
Investments, at fair market value	4,165,194	2,721,443
Current Assets		
Cash and cash equivalents	2,598,084	4,829,176
Accounts receivable (less allowance for uncollectibles of \$302,513 and \$331,775 in 1998 and 1997, respectively)	14,861,255	16,415,922
Materials and supplies, at average cost	1,728,513	1,424,312
Propane inventory, at average cost	1,787,038	2,436,200
Storage gas prepayments	2,152,605	2,926,618
Underrecovered purchased gas costs	1,552,265	1,673,389
Income taxes receivable	344,311	766,178
Deferred income taxes	-	247,487
Prepaid expenses	1,596,595	1,107,825
Total current assets	26,620,666	31,827,107
Deferred Charges and Other Assets		
Environmental regulatory assets	2,700,000	4,865,073
Environmental expenditures	3,418,166	2,372,929
Other deferred charges and intangible assets	4,063,811	4,053,068
Total deferred charges and other assets	10,181,977	11,291,070
Total Assets	\$145,233,613	\$145,718,823

See accompanying notes

CONSOLIDATED BALANCE SHEETS

Capitalization and Liabilities

At December 31,	1998	1997
Capitalization		
Stockholders' equity		
Common stock	\$ 2,479,019	\$ 2,435,142
Additional paid-in capital	24,192,188	22,581,463
Retained earnings	28,892,384	28,533,145
Less: Unearned compensation related to restricted stock awarded	(71,041)	(190,886)
Accumulated other comprehensive income	863,344	296,872
Total stockholders' equity	56,355,894	53,655,736
Long-term debt, net of current portion	37,597,000	38,226,000
Total capitalization	93,952,894	91,881,736
Current Liabilities		
Current portion of long-term debt	520,000	1,051,241
Short-term borrowings	11,600,000	7,600,010
Accounts payable	11,070,642	16,397,691
Refunds payable to customers	636,153	357,041
Accrued interest	553,444	784,533
Dividends payable	1,273,446	1,092,168
Deferred income taxes	56,100	-
Other accrued liabilities	3,754,231	3,829,497
Total current liabilities	29,464,016	31,112,181
Deferred Credits and Other Liabilities		
Deferred income taxes	13,260,282	11,490,358
Deferred investment tax credits	766,802	821,617
Environmental liability	2,700,000	4,865,073
Accrued pension costs	1,536,304	2,338,201
Other liabilities	3,553,315	3,209,657
Total deferred credits and other liabilities	21,816,703	22,724,906
Commitments and Contingencies (Notes L and M)		
Total Capitalization and Liabilities	\$145,233,613	\$145,718,823

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	1998	1997	1996
Operating Activities			
Net Income	\$ 5,302,586	\$ 5,867,612	\$ 7,781,933
Adjustments to reconcile net income to net operating cash:			
Depreciation and amortization	6,864,063	6,168,777	6,248,618
Investment tax credit adjustments	(54,815)	(54,815)	(54,815)
Deferred income taxes, net	1,711,510	1,437,206	1,794,146
Mark-to-market adjustments	(242,757)	1,144,966	(1,109,416)
Employee benefits	(801,898)	(238,826)	471,870
Employee compensation from lapsing of stock restrictions	119,845	173,643	334,745
Other, net	(171,616)	(286,147)	(32,133)
Changes in assets and liabilities:			
Accounts receivable, net	1,797,425	10,914,969	(8,597,772)
Other current assets	630,202	1,368,006	(2,766,414)
Other deferred charges	215,119	(623,138)	(977,257)
Accounts payable, net	(5,327,052)	(12,525,992)	12,048,169
Refunds payable to customers	279,112	3,307	(613,206)
Overrecovered (underrecovered) purchased gas costs	121,123	518,781	(2,245,544)
Other current liabilities	584,558	(2,193,548)	1,739,020
Net cash provided by operating activities	11,027,405	11,674,801	14,021,944
Investing Activities			
Property, plant and equipment expenditures, net	(12,021,735)	(12,370,932)	(14,025,373)
Purchases of investments	(500,000)	(36,167)	(129,406)
Net cash used by investing activities	(12,521,735)	(12,407,099)	(14,154,779)
Financing Activities			
Common stock dividends, net of amounts reinvested of \$463,231, \$382,932 and \$346,308 in 1998, 1997 and 1996, respectively	(4,298,837)	(3,846,264)	(3,368,545)
Issuance of stock - Dividend Reinvestment Plan optional cash	146,716	167,337	208,813
Issuance of stock - Retirement Savings Plan	466,759	404,297	349,031
Net borrowings (repayments) under line of credit agreements	3,999,990	(5,134,990)	7,334,990
Proceeds from issuance of long-term debt	-	9,929,711	-
Repayment of long-term debt	(1,051,390)	(3,098,455)	(881,467)
Net cash (used) provided by financing activities	(736,762)	(1,578,364)	3,642,822
Net (Decrease) Increase in Cash and Cash Equivalents	(2,231,092)	(2,310,662)	3,509,987
Cash and Cash Equivalents at Beginning of Year	4,829,176	7,139,838	3,629,851
Cash and Cash Equivalents at End of Year	\$ 2,598,084	\$ 4,829,176	\$ 7,139,838
Supplemental Disclosure of Cash Flow Information			
Cash paid for interest	\$ 3,490,993	\$ 3,243,981	\$ 2,872,973
Cash paid for income tax	\$ 2,670,580	\$ 3,500,160	\$ 2,059,441

See accompanying notes

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

For the Years Ended December 31,	1998	1997	1996
Common Stock			
Balance - beginning of year	\$ 2,435,142	\$ 2,403,978	\$ 2,365,562
Dividend Reinvestment Plan	16,240	15,398	16,514
Retirement Savings Plan	12,663	11,305	9,928
Conversion of debentures	3,115	4,461	429
USI restricted stock award agreements	-	-	10,639
Performance shares	11,859	-	-
Exercised stock options	-	-	906
Balance - end of year	2,479,019	2,435,142	2,403,978
Additional Paid-in Capital			
Balance - beginning of year	22,581,463	21,507,577	20,250,967
Dividend Reinvestment Plan	593,706	529,453	538,607
Retirement Savings Plan	454,096	392,992	328,465
Conversion of debentures	105,736	151,441	14,557
USI restricted stock award agreements	-	-	344,570
Performance shares	457,187	-	-
Exercised stock options	-	-	30,411
Balance - end of year	24,192,188	22,581,463	21,507,577
Retained Earnings			
Balance - beginning of year	28,533,145	27,113,764	23,458,776
Net income	5,302,586	5,867,612	7,781,933
Cash dividends - Chesapeake	(4,943,347)	(4,341,964)	(3,514,694)
Cash dividends - Pooled companies	-	(106,267)	(612,251)
Balance - end of year	28,892,384	28,533,145	27,113,764
Unearned Compensation			
Balance - beginning of year	(190,886)	(364,529)	(415,107)
Issuance of award	-	-	(284,167)
Amortization of prior years' awards	119,845	173,643	334,745
Balance - end of year	(71,041)	(190,886)	(364,529)
Accumulated Other Comprehensive Income			
Net of income tax expense of approximately \$552,000, \$190,000 and \$25,000 for the years 1998, 1997 and 1996, respectively	863,344	296,872	38,598
Total Stockholders' Equity	\$56,355,894	\$53,655,736	\$50,699,388

See accompanying notes

CONSOLIDATED STATEMENTS OF INCOME TAXES

For the Years Ended December 31,	1998	1997	1996
Current Income Tax Expense			
Federal	\$ 1,553,839	\$ 2,076,235	\$1,940,430
State	307,654	442,563	356,576
Investment tax credit adjustments, net	(54,815)	(54,815)	(54,815)
Total current income tax expense	1,806,678	2,463,983	2,242,191
Deferred Income Tax Expense			
Property, plant and equipment	887,175	1,335,802	581,373
Deferred gas costs	(111,416)	(204,170)	873,904
Pensions and other employee benefits	546,237	(19,508)	107,131
Unbilled revenue	(16,198)	(104,632)	54,320
Contributions in aid of construction	(104,003)	(33,028)	(6,979)
Environmental expenditures	415,845	249,417	108,578
Other	(198,574)	16,332	126,098
Total deferred income tax expense (1)	1,419,066	1,240,213	1,844,425
Total Income Tax Expense	\$ 3,225,744	\$ 3,704,196	\$4,086,616
Reconciliation of Effective Income Tax Rates			
Federal income tax expense at 34%	\$ 2,899,632	\$ 3,254,412	\$4,035,307
State income taxes, net of Federal benefit	363,041	399,213	537,566
Acquisition of subchapter S Corporation (2)	-	317,821	(268,211)
Other	(36,929)	(267,250)	(218,046)
Total Income Tax Expense	\$ 3,225,744	\$ 3,704,196	\$4,086,616
Effective income tax rate	37.8%	38.7%	34.4%

At December 31,	1998	1997
Deferred Income Taxes		
Deferred income tax liabilities:		
Property, plant and equipment	\$13,222,141	\$12,095,782
Deferred gas costs	546,391	649,681
Environmental costs	1,358,443	855,997
Other	1,077,008	704,991
Total deferred income tax liabilities	16,203,983	14,306,451
Deferred income tax assets:		
State operating loss carryforwards	72,041	57,303
Unbilled revenue	984,510	968,311
Pension and other employee benefits	884,286	831,735
Self insurance	625,602	585,995
Other	321,162	620,236
Total deferred income tax assets	2,887,601	3,063,580
Deferred Income Taxes		
Per Consolidated Balance Sheet	\$13,316,382	\$11,242,871

(1) Includes \$156,000, \$208,000 and \$392,000 of deferred state income taxes for the years 1998, 1997 and 1996, respectively.

(2) Accounted for as a pooling of interests (see Note B to the Consolidated Financial Statements).

See accompanying notes

A. Summary of Accounting Policies

Nature of Business

Chesapeake Utilities Corporation (the "Company") is engaged in natural gas distribution to approximately 37,100 customers located in southern Delaware, Maryland's Eastern Shore and Central Florida. The Company's natural gas transmission subsidiary operates a pipeline from various points in Pennsylvania and northern Delaware to the Company's Delaware and Maryland distribution divisions, as well as other utility and industrial customers in Delaware and the Eastern Shore of Maryland. The Company's propane distribution and marketing segment provides distribution service to approximately 35,000 customers in southern Delaware, the Eastern Shore of Maryland and Virginia, and markets propane to a number of large independent oil and petrochemical companies, resellers, and propane distribution companies in the southeastern United States. The advanced information services segment provides consulting, custom programming, training and development tools for

national and international clients.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries. Investments in entities in which the Company owns more than 20 percent but 50 percent or less, are accounted for by the equity method. All significant intercompany transactions have been eliminated in consolidation.

System of Accounts

The natural gas distribution divisions of the Company located in Delaware, Maryland and Florida are subject to regulation by the Delaware, Maryland and Florida Public Service Commissions with respect to their rates for service, maintenance of their accounting records and various other matters. Eastern Shore Natural Gas Company ("Eastern Shore") is an open access pipeline and is subject to regulation by the Federal Energy Regulatory Commission ("FERC"). The Company's financial statements are prepared on the basis of generally accepted accounting principles which give appropriate recognition to the ratemaking and accounting practices and policies of the various commissions. The propane distribution and marketing and advanced information services segments are not subject to regulation with respect to rates or maintenance of accounting records.

Cash and Cash Equivalents

The Company's 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 are considered cash equivalents.

Property, Plant, Equipment and Depreciation Utility property is stated at original cost while the assets of the propane segment are valued at cost. The costs of repairs and minor replacements are charged to income as incurred and the costs of major renewals and betterments are capitalized. Upon retirement or disposition of utility property, the recorded cost of removal, net of salvage value, is charged to accumulated depreciation. Upon retirement or disposition of non-utility property, the gain or loss, net of salvage value, is charged to income. The provision for depreciation is computed using the straight-line method at rates which will amortize the unrecovered cost of depreciable property over the estimated useful life. Depreciation and amortization expense for financial statement purposes is provided at an annual rate for each segment. Average rates for 1998 were 5% and 3% for the natural gas distribution and transmission segments, respectively, 5% for propane distribution and marketing, 16% for advanced information services and 6% for general plant.

Environmental Regulatory Assets

Environmental regulatory assets represent amounts related to environmental liabilities for which cash expenditures have not been made. As expenditures are incurred, the environmental liability is reduced along with the environmental regulatory asset. These amounts, awaiting ratemaking treatment, are recorded to either environmental expenditures as an asset or accumulated depreciation as cost of removal. Environmental expenditures are amortized and/or recovered through a rider to base rates in accordance with the ratemaking treatment granted in each jurisdiction.

Other Deferred Charges and Intangible Assets Other deferred charges include discount, premium and issuance costs associated with long-term debt and rate case expenses. The discount, premium and issuance costs are deferred, then amortized over the original lives of the respective debt issues. Gains and losses on the reacquisition of debt are amortized over the remaining lives of the original issuances. Rate case expenses are deferred, then amortized over periods approved by the applicable regulatory authorities. Intangible assets are associated with the acquisition of non-utility companies, and are amortized on a straight-line basis over a period of five to 40 years. A summary of intangible assets is as follows:

	1998	1997
Gross intangibles	\$2,776,000	\$2,776,000
Accumulated amortization	(1,288,000)	(1,133,000)
Net unamortized balance	\$1,488,000	\$1,643,000

Income Taxes and Investment Tax Credit Adjustments The Company files a consolidated federal income tax return. Income tax expense allocated to the Company's subsidiaries is based upon their respective taxable incomes and tax credits.

Deferred tax assets and liabilities are recorded for the tax effect of temporary differences between the financial statements and tax bases of assets and liabilities, and are measured using current effective income tax rates. The portion of the Company's deferred tax liabilities applicable to utility operations which has not been reflected in current service rates represents income taxes recoverable through future rates. Investment tax credits on utility property have been deferred and are allocated to income ratably over the lives of the subject property.

The Company had state tax loss carryforwards of \$980,000 and \$818,000 at December 31, 1998 and 1997, respectively. The Company expects to use all of the loss carryforwards; therefore, no valuation allowance was recorded at December 31, 1998 or 1997. The loss carryforwards expire in 2006 through 2013.

Financial Instruments

Xeron, the Company's wholesale propane 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, the Company's trading contracts are recorded at fair value, net of future servicing costs. Changes in market price are recognized as gains or losses in the period of change. The resulting unrealized gains and losses are recorded as assets or liabilities.

Operating Revenues

Revenues for the natural gas distribution divisions of the Company are based on rates approved by the various public service commissions. Customers' base rates may not be changed without formal approval by these commissions. With the exception of the Company's Florida division, the Company recognizes revenues from meters read on a monthly cycle basis. This practice results in unbilled and unrecorded revenue from the cycle date through month-end. The Florida division recognizes revenues based on services rendered and records an amount for gas delivered but not billed.

Chesapeake's natural gas distribution divisions each have a gas cost recovery mechanism that provides for the adjustment of rates charged to customers as gas costs fluctuate. These amounts are collected or refunded through adjustments to rates in subsequent periods.

The Company charges flexible rates to the natural gas distribution segment's industrial interruptible customers to make them competitive with alternative types of fuel. Based on pricing, these customers can choose natural gas or alternative types of supply. Neither the Company nor the customer is contractually obligated to deliver or receive natural gas.

The natural gas transmission segment became an open access pipeline on November 1, 1997 with revenues based on rates approved by FERC. Before open access, only portions of revenues were based on rates approved by FERC.

The propane distribution operation records revenues on either an "as delivered" or on a "metered" basis depending on the customer type. The wholesale propane marketing operation calculates revenues daily on a mark-to-market basis for open contracts.

Earnings Per Share

The calculations of both basic and diluted earnings per share are presented below.

For the Years Ended December 31,	1998	1997	1996
Calculation of Basic Earnings Per Share:			
Net Income	\$5,302,586	\$5,867,612	\$7,781,933
Weighted Average Shares Outstanding	5,060,328	4,972,089	4,912,136
Basic Earnings Per Share	\$ 1.05	\$ 1.18	\$ 1.58
Calculation of Diluted Earnings Per Share:			
Reconciliation of Numerator:			
Net Income - basic	\$5,302,586	\$5,867,612	\$7,781,933
Effect of 8.25% Convertible debentures	196,333	204,070	207,825
Adjusted numerator - diluted	\$5,498,919	\$6,071,682	\$7,989,758
Reconciliation of Denominator:			
Weighted Shares Outstanding - basic	5,060,328	4,972,089	4,912,136
Effect of 8.25% Convertible debentures	226,203	238,353	242,742
Adjusted denominator - diluted	5,286,531	5,210,442	5,154,878
Diluted Earnings per Share	\$ 1.04	\$ 1.17	\$ 1.55

Certain Risks and Uncertainties

The financial statements are prepared in conformity with generally accepted accounting principles that require management to make estimates in measuring assets and liabilities and related revenue and expenses (see Note L to the Consolidated Financial Statements for significant estimates). These estimates involve judgements with respect to, among other things, various future economic factors that are difficult to predict and are beyond the control of the Company; therefore, actual results could differ from those estimates.

The Company records certain assets and liabilities in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71. If the Company were required to terminate application of SFAS No. 71 for regulated operations, all such deferred amounts would be recognized in the income statement at that time, resulting in a charge to earnings, net of applicable income taxes.

FASB Statements and Other Authoritative Pronouncements Issued Derivative Instruments and Hedging Activities In June 1998, the Financial Accounting Standards Board ("FASB") issued SFAS No. 133, establishing accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. This statement does not allow retroactive application to financial statements for prior periods. Chesapeake will adopt the requirements of this standard in the first quarter of 2000, as required. The Company believes that adoption of this statement will not have a material impact on the Company's financial position or results of operations.

The Emerging Issues Task Force released Issue 98-10, "Accounting for Energy Trading and Risk Management Activities." The Company records its use of derivatives in accordance with the standard by marking open positions to market value. The adoption of the pronouncement is not expected to have a material impact on the financial position or results of operations of the Company.

Restatement and Reclassification of Prior Years' Amounts Certain prior years' amounts have been reclassified to conform to current year presentation. Additionally, prior year amounts have been restated to reflect acquisitions accounted for as poolings of interests.

B. Business Combinations

In May 1998, Chesapeake acquired all of the outstanding common stock of Xeron, Inc, based in Houston, Texas for 475,000 shares of

Chesapeake common stock. Xeron markets propane to a number of large independent oil and petrochemical companies, resellers, and southeastern retail propane companies. The transaction was accounted for as a pooling of interests.

In March 1998, the Company acquired Sam Shannahan Well Co., Inc., operating as Tolan Water Service in exchange for 25,000 shares of Chesapeake's common stock. Tolan provides water conditioning services to approximately 3,000 residential, commercial and industrial customers on the Delmarva Peninsula. This transaction was also accounted for as a pooling of interests.

The results of operations for the separate companies and the combined amounts are presented in the consolidated financial statements as follows.

	Five months ended May 31, 1998 *	Year Ended December 31, 1997	Year Ended December 31, 1996
Operating Revenues			
Chesapeake	\$ 54,750,771	\$ 122,774,593	\$ 130,213,409
Xeron	37,136,067	98,164,932	128,633,042
Tolan	719,523	1,549,739	1,255,749
Combined	\$ 92,606,361	\$ 222,489,264	\$ 260,102,200
Net Income			
Chesapeake	\$ 4,385,817	\$ 5,682,946	\$ 7,604,915
Xeron	21,704	128,910	158,991
Tolan	2,346	55,756	18,027
Combined	\$ 4,409,867	\$ 5,867,612	\$ 7,781,933

* Statements for the five months ended May 31, 1998 are unaudited.

In March 1997, the Company acquired all of the outstanding common stock of Tri-County Gas Company, Inc. and associated properties. Tri-County's principal business was the distribution of propane to both retail and wholesale customers in southern Delaware, the Eastern Shore of Maryland and Virginia. Six hundred thirty-nine thousand shares of the Company's common stock were exchanged in the transaction, which was accounted for as a pooling of interests.

All prior period consolidated financial statements presented have been restated to include the combined results of operations, financial position and cash flows of each of the business combinations discussed above. All material intercompany transactions have been eliminated in consolidation.

C. Segment Information

Chesapeake uses the management approach to identify operating segments. Chesapeake organizes its business around differences in products or services and the operating results of every segment are regularly reviewed by the Company's chief operating decision maker in order to make decisions about resources and to assess performance.

The following table presents information about the Company's reportable segments.

For the Years Ended December 31,	1998	1997	1996
Operating Revenues, Unaffiliated Customers			
Natural gas distribution	\$ 65,384,413	\$ 75,940,968	\$ 74,904,100
Natural gas transmission	3,199,032	12,164,369	15,188,752
Propane distribution and marketing	102,872,909	125,159,336	161,812,156
Advanced information services	10,330,703	7,636,407	6,903,246
Other	1,781,738	1,588,184	1,293,946
Total operating revenues, unaffiliated customers	\$183,568,795	\$222,489,264	\$260,102,200
Intersegment Revenues *			
Natural gas distribution	\$ 40,494	\$ 18,970	\$ 12,232
Natural gas transmission	7,269,620	19,282,359	21,543,352
Propane distribution and marketing	-	52,230	2,059
Advanced information services	-	149,602	326,913
Other	634,032	523,007	332,512
Total intersegment revenues	\$ 7,944,146	\$ 20,026,168	\$ 22,217,068
Operating Income Before Income Taxes			
Natural gas distribution	\$ 4,696,759	\$ 5,498,471	\$ 7,167,237
Natural gas transmission	4,117,366	3,721,148	2,458,442
Propane distribution and marketing	971,215	1,157,543	2,668,839
Advanced information services	1,316,158	1,045,912	1,056,201
Other	461,174	637,971	478,571
Total	11,562,672	12,061,045	13,829,290
Eliminations	60,009	32,727	153,591
Total operating income before income taxes	\$ 11,622,681	\$ 12,093,772	\$ 13,982,881
Depreciation and Amortization			
Natural gas distribution	\$ 3,330,624	\$ 3,076,654	\$ 2,907,831
Natural gas transmission	1,050,714	892,258	697,834
Propane distribution and marketing	1,334,414	1,214,918	1,720,631
Advanced information services	183,553	122,081	131,877
Other	209,897	169,506	147,757
Total depreciation and amortization	\$ 6,109,202	\$ 5,475,417	\$ 5,605,930
Capital Expenditures			
Natural gas distribution	\$ 8,512,661	\$ 6,569,865	\$ 6,961,652
Natural gas transmission	1,505,830	2,959,019	5,567,509
Propane distribution and marketing	1,544,992	2,820,166	2,189,368
Advanced information services	246,153	273,351	162,189
Other	840,186	848,680	517,997
Total capital expenditures	\$ 12,649,822	\$ 13,471,081	\$ 15,398,715
Identifiable Assets, at December 31,			
Natural gas distribution	\$ 77,756,422	\$ 78,732,860	\$ 77,426,232
Natural gas transmission	24,862,165	24,781,292	23,981,989
Propane distribution and marketing	27,526,019	31,831,616	44,073,080
Advanced information services	2,304,609	1,751,192	1,496,419
Other	12,784,398	8,621,863	8,808,724
Total identifiable assets	\$145,233,613	\$145,718,823	\$155,786,444

* All significant intersegment revenues have been eliminated from consolidated revenues.

D. Fair Value of Financial Instruments

Various items within the balance sheet are considered to be financial instruments because they are cash or are to be settled in cash. The carrying values of these items generally approximate their fair value (see Note E to the Consolidated Financial Statements for disclosure of fair value of investments). The fair value of the Company's open forward and futures contracts at December 31, 1998 and December 31, 1997 based on market rates were \$207,000 and \$36,000, respectively. The fair value of the Company's long-term debt is estimated using a discounted cash flow methodology. The estimated fair value of the Company's long-term debt at December 31, 1998, including current maturities, is approximately \$41.6 million as compared to a carrying value of \$38.1 million. At December 31, 1997, the estimated fair value was approximately \$40.7 million as compared to a carrying value of \$38.8 million. These estimates are based on published corporate borrowing rates for debt instruments with similar terms and average maturities.

E. Investments

The investment balance at December 31, 1998 and 1997 consists primarily of a

7.3% ownership interest in the common stock of Florida Public Utilities Company ("FPU"). The Company has classified its investment in FPU as an "Available for Sale" security, which requires that all unrealized gains and losses be excluded from earnings and be reported net of income tax as a separate component of stockholders' equity. At December 31, 1998 and 1997, the market value exceeded the aggregate cost basis of the Company's portfolio by \$1,552,000 and \$487,000, respectively. In August 1998, the Company entered into an agreement to sell its investment in FPU for \$16.50 per share to The Southern Company. The execution of the agreement is contingent on the approval of the Securities and Exchange Commission, which is expected to be obtained in 1999. Once regulatory approval is received, the Company will recognize a \$1,415,000 pre-tax gain or \$863,000, after taxes.

F. Common Stock and Additional Paid-in Capital The following is a schedule of changes in the Company's shares of common stock.

For the Years Ended December 31,	1998	1997	1996 (1)
Common Stock: Shares issued and outstanding (2)			
Balance - beginning of year	5,004,078	4,939,515	4,860,588
Dividend Reinvestment Plan (3)	32,925	32,169	33,926
Sale of stock to Company's Retirement Savings Plan	26,018	23,228	20,398
Conversion of debentures	6,401	9,166	881
Performance shares	24,366	-	-
USI restricted stock award agreements	-	-	21,859
Exercised stock options	-	-	1,863
Balance - end of year	5,093,788	5,004,078	4,939,515

(1) The 1996 beginning balance has been restated to include 639,000, 25,000 and 475,000 shares of Common Stock that were issued to effect the business combinations with Tri-County Gas Company, Inc., Tolan Water Service and Xeron, Inc., respectively.

(2) 12,000,000 shares are authorized at a par value of \$.4867 per share.

(3) Includes dividends and reinvested optional cash payments.

G. Long-term Debt

The outstanding long-term debt, net of current maturities, is as follows:

At December 31,	1998	1997
First mortgage sinking fund bonds:		
9.37% Series I, due December 15, 2004	\$ 3,780,000	\$ 4,300,000
8.25% Convertible debentures, due March 1, 2014	3,817,000	3,926,000
Uncollateralized senior notes:		
7.97% note, due February 1, 2008	10,000,000	10,000,000
6.91% note, due October 1, 2010	10,000,000	10,000,000
6.85% note, due January 1, 2012	10,000,000	10,000,000
Total long-term debt	\$37,597,000	\$38,226,000

Annual maturities of consolidated long-term debt for the next five years are as follows: \$1,520,000 for 1999, \$2,665,091 for the years 2000 through 2002 and \$3,665,091 for 2003.

On December 15, 1997, the Company issued \$10 million of 6.85% senior notes due January 1, 2012. The Company used the proceeds to repay a portion of the Company's short-term borrowing.

The convertible debentures may be converted, at the option of the holder, into shares of the Company's common stock at a conversion price of \$17.01 per share. During 1998, \$109,000 of debentures were converted. The debentures are redeemable at the option of the holder, subject to

an annual non-cumulative maximum limitation of \$200,000 in the aggregate. At the Company's option, the debentures may be redeemed at the stated amounts.

Indentures to the long-term debt of the Company and its subsidiaries contain various restrictions. The most stringent restrictions state that the Company must maintain equity of at least 40% of total capitalization, the times interest earned ratio must be at least 2.5 and the Company cannot, until the retirement of its Series I bonds, pay any dividends after December 31, 1988 which exceed the sum of \$2,135,188 plus consolidated net income recognized on or after January 1, 1989. As of December 31, 1998, the amounts available for future dividends permitted by the Series I covenant approximated \$14.7 million.

A portion of the natural gas distribution plant assets owned by the Company are subject to a lien under the mortgage pursuant to which the Company's first mortgage sinking fund bonds are issued.

H. Short-term Borrowing

The Board of Directors has authorized the Company to borrow up to \$20.0 million from various banks and trust companies. As of December 31, 1998, the Company had three unsecured bank lines of credit totaling \$28.0 million, none of which required compensating balances. Under these lines of credit at December 31, 1998 and 1997, the Company had short-term debt outstanding of \$11.6 million and \$7.6 million, respectively, with a weighted average interest rate of 5.56% and 5.63%, respectively.

I. Lease Obligations

The Company has entered several operating lease arrangements for office space at various locations. Rent expense related to these leases was \$309,000, \$343,000 and \$359,000 for 1998, 1997 and 1996, respectively. Future minimum payments under the Company's current lease agreements are \$309,000, \$297,000, \$261,000, \$187,000 and \$169,000 for the years of 1999 through 2003, respectively; and \$299,000 thereafter.

J. Employee Benefits Plans

Pension Plan

Through December 31, 1998, the Company sponsored a defined benefit pension plan covering substantially all of its employees (see Enhanced Retirement Savings Plan). Benefits under the plan are based on each participant's years of service and highest average compensation. The Company's funding policy provides that payments to the trustee shall be equal to the minimum funding requirements of the Employee Retirement Income Security Act of 1974.

In December 1998, the Company restructured the employee benefits plans to be competitive with employers in similar industries. Chesapeake offered current participants of the defined benefit plan the option to remain in the current plan or receive a one-time payout and enroll in an enhanced retirement savings plan. Chesapeake closed the defined benefit plan to new participants, effective December 31, 1998. Based on the election options selected by the employees, the Company reduced their accrued pension liability to \$1,283,088. Based on the change in the accrued liability, the Company was able to record a curtailment gain of \$1,224,298 in 1998.

The following schedule sets forth the funded status of the pension plan at December 31, 1998 and 1997:

At December 31,	1998	1997
Change in benefit obligation:		
Benefit obligation at beginning of year	\$11,534,355	\$10,265,987
Service cost	838,177	680,192
Interest cost	803,727	732,188
Effect of curtailment	(1,224,298)	-
Change in discount rate	952,552	-
Actuarial (gain) loss	(384,492)	146,559
Benefits paid	(332,136)	(290,571)
Benefit obligation at end of year	12,187,885	11,534,355
Change in plan assets:		
Fair value of plan assets at beginning of year	13,592,699	10,720,514
Actual return on plan assets	1,324,606	2,427,768
Employer contribution	-	734,988
Benefits paid	(332,136)	(290,571)
Fair value of plan assets at end of year	14,585,169	13,592,699
Funded Status	2,397,284	2,058,344
Unrecognized transition obligation	(111,371)	(126,475)
Unrecognized prior service cost	(67,152)	(71,851)
Unrecognized net gain	(3,501,849)	(4,038,679)
Accrued pension cost	\$(1,283,088)	\$(2,178,661)
Assumptions:		
Discount rate	6.75%	7.25%
Rate of compensation increase	4.75%	4.75%
Expected return on plan assets	8.50%	8.50%

Net periodic pension costs for the defined pension benefit plan for 1998, 1997 and 1996 include the following components:

For the Years Ended December 31,	1998	1997	1996
Components of net periodic pension cost:			
Service cost	\$ 838,177	\$ 680,192	\$ 656,985
Interest cost	803,727	732,188	658,238
Expected return on assets	(1,149,754)	(898,037)	(784,924)
Amortization of:			
Transition assets	(15,104)	(15,104)	(15,104)
Prior service cost	(4,699)	(4,699)	(4,699)
Actuarial gain	(143,622)	(88,900)	(68,425)
Net periodic pension cost	328,725	405,640	442,071
Curtailement gain	(1,224,298)	-	-
Amounts capitalized as construction costs	(31,107)	(33,942)	(38,860)
Total pension cost accruals	\$ (926,680)	\$ 371,698	\$ 403,211

Retirement Savings Plan

The Company sponsors a Retirement Savings Plan, a 401(k) plan, that provides participants a mechanism for making contributions for retirement savings. Each participant may make pre-tax contributions up to 15% of eligible base compensation subject to IRS limitations. Based on each participant's years of service, the Company makes a contribution matching 60% or 100% of each participant's pre-tax contributions, not to exceed 6% of the participant's eligible compensation for the plan year. The Company's contributions totaled \$495,000, \$404,000 and \$353,000 for the years ended December 31, 1998, 1997 and 1996, respectively. As of December 31, 1998, there are 30,356 shares reserved to fund future contributions to the Retirement Savings Plan.

Enhanced Retirement Savings Plan

Effective January 1, 1999, the Company will offer an enhanced 401(k) plan to all new employees, as well as existing employees that elected to no longer participate in the defined benefit plan. The Company will make a matching contribution of each employee's pre-tax contribution of up to 6% of the eligible compensation for the year. The match will be between 100% and 200% based on a combination of the employee's age and years of service. The first 100% of the funds will be matched with Chesapeake common stock. The remaining match will be invested in the Company's 401(k) plan according to each employee's election options.

Other Post-retirement Benefits

The Company sponsors a defined benefit post-retirement health care and life insurance plan that covers substantially all natural gas and corporate employees. The Company had deferred approximately \$126,000, which represented the difference between the Maryland division's SFAS No. 106 expense and its actual pay-as-you-go cost. The amount is being amortized over five years starting in 1995. The unamortized balance was \$50,000 at December 31, 1998.

Net periodic post-retirement costs for 1998, 1997 and 1996 include the following components:

For the Years Ended December 31,	1998	1997	1996
Components of net periodic post-retirement cost:			
Service cost	\$ 3,361	\$ 3,287	\$ 2,820
Interest cost	59,321	60,221	54,651
Amortization of:			
Transition obligation	27,859	27,859	27,859
Actuarial loss	6,071	1,554	-
Net periodic post-retirement cost	96,612	92,921	85,330
Amounts capitalized as construction costs	(22,459)	(16,274)	(16,672)
Amounts amortized (deferred)	25,254	25,254	25,254
Total post-retirement cost accruals	\$99,407	\$101,901	\$93,912

The following schedule sets forth the funded status of the post-retirement health care and life insurance plan:

At December 31,	1998	1997
Change in benefit obligation:		
Benefit obligation at beginning of year	\$ 868,899	\$ 791,871
Retirees	14,236	53,604
Fully-eligible active employees	674	7,978
Other active	3,251	15,446
Benefit obligation at end of year	\$ 887,060	\$ 868,899
Funded Status	\$(887,060)	\$(868,899)
Unrecognized transition obligation	217,295	245,154
Unrecognized net loss	165,160	147,422
Accrued post-retirement cost	\$(504,605)	\$(476,323)
Assumptions:		
Discount rate	6.75%	7.25%

The health care inflation rate for 1998 is assumed to be 9.0%. This rate is projected to gradually decrease to an ultimate rate of 5% by the year 2007. A one percentage point increase in the health care inflation rate from the assumed rate would increase the accumulated post-retirement benefit obligation by approximately \$105,000 as of January 1, 1999, and would increase the aggregate of the service cost and interest cost components of net periodic post-retirement benefit cost for 1999 by approximately \$8,000.

K. Executive Incentive Plans

The Performance Incentive Plan ("the Plan") adopted in 1992, provides for the granting of stock options to certain officers of the Company over a 10-year period. The Plan provides participants an option to purchase shares of the Company's common stock, exercisable in cumulative installments of up to one-third on each anniversary of the commencement of the award period. The Plan also enables participants the right to earn performance shares upon the Company's achievement of certain performance goals as set forth in the specific agreements associated with particular options and/or performance shares.

The Company has executed Stock Option Agreements for a three-year performance period ending December 31, 2000 with certain executive officers. One-half of these options become exercisable over time and the other half become exercisable if certain performance targets are achieved. Chesapeake also executed Performance Share Agreements for the same period with certain other executive officers. Each year participants are eligible to earn a maximum number of performance shares equal to one-third of the total number of performance shares granted, based on the Company's achievement of certain performance goals. The Company recorded \$49,000 of compensation expense associated with these performance shares in 1998.

In November 1994, the Company executed Tandem Stock Option and Performance Share Agreements ("Agreements") with certain executive officers. During the three-year period ended December 31, 1997, the performance goals set forth in the Agreements were achieved. Following the approval of the Board of Directors on February 27, 1998, the Company issued 44,081 performance shares. At that time, 44,906 stock options expired. The Company recorded \$416,000 and \$227,000 to recognize the compensation expense associated with these performance shares in 1997 and 1996, respectively.

Changes in outstanding options were as follows:

	1998		1997		1996	
	Number of shares	Option Price	Number of shares	Option Price	Number of shares	Option Price
Balance - beginning of year	208,543	\$12.625 - \$20.50	113,051	\$12.625 - \$20.50	125,186	\$12.625 - \$12.75
Options granted			95,492	\$20.50		
Options expired	(44,906)	\$12.625				
Options exercised					(12,135)	\$12.75
Balance - end of year	163,637	\$12.75 - \$20.50	208,543	\$12.625 - \$20.50	113,051	\$12.625 - \$12.75
Exercisable	68,145	\$12.75	98,083	\$12.625 - \$12.75	83,114	\$12.625 - \$12.75

In December 1997, the Company granted stock options to certain executive officers of the Company. As required by SFAS No. 123, the pro forma information as if fair value based accounting had been used to account for the stock-based compensation costs is shown below.

	1998	1997
For the Years Ended December 31,		
Pro forma Net Income	\$5,262,468	\$5,864,269
Pro forma Earnings Per Share:		
Basic	\$ 1.04	\$ 1.18
Diluted	\$ 1.03	\$ 1.16
Assumptions:		
Dividend yield	4.73%	4.73%
Expected volatility	15.53%	15.53%
Risk-free interest rate	5.89%	5.89%
Expected lives	4 years	4 years

Certain key USI employees entered into restricted stock award agreements under which shares of Chesapeake common stock were issued over a five-year period beginning in 1992 as certain targets were met. Restrictions lapse over a five to ten-year period from the award date. At December 31, 1998 and 1997, respectively, 4,371 and 12,515 shares valued at \$71,041 and \$190,886 remain restricted.

L. Environmental Commitments and Contingencies The Company is currently participating in the investigation, assessment or remediation of three former gas manufacturing plant sites located in different jurisdictions, including the exploration of corrective action options to remove environmental contaminants. The Company has accrued liabilities for two of these sites, the Dover Gas Light and Salisbury Town Gas Light sites.

With respect to the Dover Gas Light site, the Company and General Public Utilities Corporation, Inc. ("GPU") have been ordered by the Environmental Protection Agency ("EPA") to fund or implement the EPA's Record of Decision ("ROD") on the appropriate remedial activities to be performed, which include both soil and ground-water remedies.

During the fourth quarter of 1998, the Company started the soil remediation process at that site at a cost of \$450,000. Over the next twelve to eighteen months, the Company will finalize the soil remediation and initiate the ground-water remedial activities.

The Company's independent consultants have prepared preliminary estimates of the costs of two potentially acceptable alternatives to complete the ground- water remediation activities at the site. The costs to remediate the ground- water range from a low of \$390,000 in capital and \$37,000 per year of operating costs; to a high of \$4.0 million in capital and \$500,000 per year in operating costs. In both cases, the operating costs are assumed to last for 30 years. A decision by the EPA as to the most appropriate ground-water remediation method is likely in 1999. The capital costs necessary to begin remediation are expected to be incurred over the next twelve to eighteen months.

Chesapeake cannot predict the ground-water remediation the EPA will select; therefore, the Company has accrued \$2.1 million at December 31, 1998 for the Dover site and has recorded a regulatory asset for an equivalent amount. Of this amount, \$1.5 million is for ground-water remediation and \$600,000 is for the remaining soil remediation. The \$1.5 million represents the low end of the ground-water remedy estimates described above.

The Company initiated litigation against one of the other potentially responsible parties for contribution to the remedial costs incurred by Chesapeake in connection with complying with the ROD. At this time, management cannot predict the outcome of the litigation or the amount of proceeds to be received, if any. Management believes that the Company will be equitably entitled to contribution from other responsible parties for a portion of the expenses to be incurred in connection with the remedies selected in the ROD. The Company expects that it will be able to recover actual costs incurred, which are not recovered from other responsible parties, exclusive of associated carrying costs, through the ratemaking process in accordance with environmental cost recovery rider provisions currently in effect.

In cooperation with the Maryland Department of the Environment ("MDE"), in 1996 the Company completed construction and began remediation procedures at the Salisbury site. In addition, the Company began quarterly reporting of the remediation and monitoring results to the MDE. The Company has established a liability with respect to the Salisbury site of \$600,000 as of December 31, 1998. This amount is based on the estimated operating costs of the remediation facilities over the next five years. A corresponding regulatory asset has been recorded, reflecting the Company's belief that costs incurred will be recoverable in base rates.

In addition, the Company has a site located in the state of Florida which is currently being evaluated. At this time, no estimate of liability can be made. It is management's opinion that any unrecovered current costs and any other future costs incurred will be recoverable through future rates or sharing arrangements with other responsible parties.

ENVIRONMENTAL COSTS INCURRED

At December 31,	1998	1997
Delaware	\$6,846,722	\$5,317,380
Maryland	2,541,263	2,368,168
Florida	696,847	692,391
Total costs incurred	10,084,832	8,377,939
Less: Amounts, net of insurance proceeds, which have been approved for ratemaking treatment	(8,391,953)	(7,319,496)
Amounts pending ratemaking recovery	\$1,692,879	\$1,058,443

M. Other Commitments and Contingencies

Natural Gas Supply

The Company's natural gas distribution operations have entered into contractual commitments for daily entitlements of natural gas from various suppliers. The contracts have various expiration dates.

Other

The Company is involved in certain legal actions and claims arising in the normal course of business. The Company is also involved in certain legal and administrative proceedings before various governmental agencies concerning rates. In the opinion of management, the ultimate disposition of these proceedings will not have a material effect on the consolidated financial position of the Company.

N. Quarterly Financial Data (Unaudited)

In the opinion of the Company, 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 the Company's business, there are substantial variations in operations reported on a quarterly basis.

For the Quarters Ended, March 31 June 30 September 30 December 31*

1998

Operating Revenue	\$60,169,102	\$43,594,944	\$36,231,924	\$43,572,825
Operating Income	4,744,218	962,101	(459,965)	3,194,728
Net Income	4,000,602	263,751	(1,266,498)	2,304,731
Earnings per share:				
Basic	\$ 0.80	\$ 0.05	\$ (0.25)	\$ 0.45
Diluted	\$ 0.77	\$ 0.05	\$ (0.25)	\$ 0.44

1997

Operating Revenue	\$76,302,285	\$44,918,820	\$41,680,719	\$59,587,440
Operating Income	4,148,755	1,392,667	(7,026)	3,132,068
Net Income	3,433,648	707,300	(762,784)	2,489,448
Earnings per share:				
Basic	\$ 0.69	\$ 0.14	\$ (0.15)	\$ 0.50
Diluted	\$ 0.67	\$ 0.14	\$ (0.15)	\$ 0.49

* Results for the fourth quarter of 1998 reflect a one-time pension plan curtailment gain of approximately \$750,000, net of income tax expense. See Note J to the Consolidated Financial Statements.

OPERATING STATISTICS

For the Years Ended December 31,	1998	1997	1996	1995	1994 (1)
Revenues (in thousands)					
Natural gas					
Residential	\$ 19,274	\$ 21,540	\$ 18,256	\$ 14,857	\$15,228
Commercial	15,243	16,557	14,339	11,383	11,594
Industrial	15,953	22,625	28,546	36,898	32,718
Sale for resale	11,683	23,010	24,481	12,459	9,586
Transportation	6,120	4,212	3,369	2,993	2,639
Other	310	162	1,102	515	(50)
Total natural gas revenues	68,583	88,106	90,093	79,105	71,715
Propane distribution and marketing (2)	102,873	125,159	161,812	147,596	17,789
Other	12,113	9,224	8,197	8,584	6,173
Total revenues	\$183,569	\$222,489	\$260,102	\$235,285	\$95,677
Volumes					
Natural gas deliveries (in MMCF)					
Residential	1,636	1,753	1,987	1,686	1,665
Commercial	1,907	2,113	2,059	1,792	1,771
Industrial	3,115	5,975	7,553	13,622	10,752
Sale for resale	1,194	1,200	1,065	990	998
Transportation	13,548	12,231	12,138	11,131	7,542
Total natural gas deliveries	21,400	23,272	24,802	29,221	22,728
Propane distribution (in thousands of gallons) (2)	25,979	26,682	29,975	26,184	18,395
Customers					
Natural gas					
Residential	32,473	31,277	30,349	29,285	28,260
Commercial	4,416	4,288	4,151	4,030	3,879
Industrial (3)	236	229	210	212	204
Sale for resale (3)	3	3	3	3	3
Total natural gas customers	37,128	35,797	34,713	33,530	32,346
Propane distribution	34,988	33,998	32,218	31,372	22,180
Total customers	72,116	69,795	66,931	64,902	54,526

- (1) 1994 has not been restated to include the business combinations with Tri-County Gas Company, Inc., Tolan Water Service or Xeron, Inc.
(2) 1994 amounts exclude \$2,895,000 in revenue and nine million gallons of propane sold to one large wholesale customer.
(3) Includes transportation customers.

[GRAPH APPEARS HERE]

Natural Gas and Propane
Customer Growth

Year	Natural Gas Customers	Propane Customers
1994	32,346	22,180
1995	33,530	31,372
1996	34,713	32,218
1997	35,797	33,998
1998	37,152	34,988

[GRAPH APPEARS HERE]

Volumes Compared to Heating
Degree Days

Heating Year	Natural Gas (in MMCF)	Propane (in thousands of gallons)	Degree Days
1994	22,728	18,395	4,398
1995	29,221	26,184	4,594
1996	24,741	29,975	4,717
1997	23,268	26,682	4,430
1998	21,400	26,029	3,704

Item 9. Changes In and Disagreements With Accountants on Accounting and

Financial Disclosure

None

PART III

Item 10. Directors and Executive Officers of the Registrant

Information pertaining to the Directors of the Company is incorporated herein by reference to the Proxy Statement, under "Information Regarding the Board of Directors and Nominees", dated and to be filed on or before March 30, 1999 in connection with the Company's Annual Meeting to be held on May 18, 1999.

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 Item 10 of Part I of this Form 10-K under "Executive Officers of the Registrant."

Item 11. Executive Compensation

This information is incorporated herein by reference to the Proxy Statement, under "Report on Executive Compensation", dated and to be filed on or before March 30, 1999 in connection with the Company's Annual Meeting to be held on May 18, 1999.

Item 12. Security Ownership of Certain Beneficial Owners and Management

This information is incorporated herein by reference to the Proxy Statement, under "Beneficial Ownership of the Company's Securities", dated and to be filed on or before March 30, 1999 in connection with the Company's Annual Meeting to be held on May 18, 1999.

Item 13. Certain Relationships and Related Transactions

This information is incorporated herein by reference to the Proxy Statement, under "Beneficial Ownership of the Company's Securities", dated and to be filed on or before March 30, 1999 in connection with the Company's Annual Meeting to be held on May 18, 1999.

PART IV

Item 14. Financial Statements, Financial Statement Schedules, Exhibits and

Reports on Form 8-K

(a) The following documents are filed as part of this report:

1. Financial Statements:

- Accountants' Report dated February 12, 1999 of PricewaterhouseCoopers LLP, Independent Accountants
- Consolidated Statements of Income for each of the three years ended December 31, 1998, 1997 and 1996
- Consolidated Balance Sheets at December 31, 1998 and December 31, 1997
- Consolidated Statements of Cash Flows for each of the three years ended December 31, 1998, 1997 and 1996
- Consolidated Statements of Common Stockholders' Equity for each of the three years ended December 31, 1998, 1997 and 1996
- Consolidated Statements of Income Taxes for each of the three years ended December 31, 1998, 1997 and 1996
- Notes to Consolidated Financial Statements

2. The following additional information for the years 1998, 1997 and 1996 is submitted herewith:

- 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.

(b) Reports on Form 8-K:

None.

(c) Exhibits:

Exhibit 2(a) Agreement and Plan of Merger by and between Chesapeake Utilities Corporation and Tri-County Gas Company, Inc., filed on the Company's Form 8-K, File No. 001-11590 on January 13, 1997, is incorporated herein by reference.

Exhibit 3(a) Amended Certificate of Incorporation of Chesapeake Utilities Corporation is incorporated herein by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 1998, File No. 001-11590.

Exhibit 3(b) Amended Bylaws of Chesapeake Utilities Corporation, effective July 11, 1997, are incorporated herein by reference to Exhibit 3.2 of the Quarterly Report on Form 10-Q for the period ended June 30, 1998, File No. 001-11590.

Exhibit 4(a) Form of Indenture between the Company 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 the Company's Registration Statement on Form S-2, Reg. No. 33-26582, filed on January 13, 1989.

Exhibit 4(b) Note Agreement dated February 9, 1993, by and between the Company and Massachusetts Mutual Life Insurance Company and MML Pension Insurance Company, with respect to \$10 million of 7.97% Unsecured Senior Notes due February 1, 2008, is incorporated herein by reference to Exhibit 4 to the Company's Annual Report on Form 10-K for the year ended December 31, 1992, File No. 0-593.

Exhibit 4(c) Directors Stock Compensation Plan adopted by Chesapeake Utilities Corporation in 1995 is incorporated herein by reference to the Company's Proxy Statement dated April 17, 1995 in connection with the Company's Annual Meeting held in May 1995.

Exhibit 4(d) Note Purchase Agreement entered into by the Company on October 2, 1995, pursuant to which the Company privately placed \$10 million of its 6.91% Senior Notes due in 2010, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. The Company hereby agrees to furnish a copy of that agreement to the Commission upon request.

Exhibit 4(e) Note Purchase Agreement entered into by the Company on December 15, 1997, pursuant to which the Company privately placed \$10 million of its 6.85 senior notes due 2012, is not being filed herewith, in accordance with Item 601(b)(4)(iii) of Regulation S-K. The Company hereby agrees to furnish a copy of that agreement to the Commission upon request.

Exhibit 10(a) Service Agreement dated November 1, 1989, by and between Transcontinental Gas Pipe Line Corporation and Eastern Shore Natural Gas Company, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1989, File No. 0-593.

Exhibit 10(b) Service Agreement dated November 1, 1989, by and between Columbia Gas Transmission Corporation and Eastern Shore Natural Gas Company, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1989, File No. 0-593.

Exhibit 10(c) Service Agreement for General Service dated November 1, 1989, by and between Florida Gas Transmission Company and Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990, File No. 0-593.

Exhibit 10(d) Service Agreement for Preferred Service dated November 1, 1989, by and between Florida Gas Transmission Company and Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990, File No. 0-593.

Exhibit 10(e) Service Agreement for Firm Transportation Service dated November 1, 1989, by and between Florida Gas Transmission Company and Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990, File No. 0-593.

Exhibit 10(f) Form of Service Agreement for Interruptible Sales Services dated May 11, 1990, by and between Florida Gas Transmission Company and Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990, File No. 0-593.

Exhibit 10(g) Interruptible Transportation Service Agreement dated February 23, 1990, by and between Florida Gas Transmission Company and Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990, File No. 0-593.

Exhibit 10(h) Interruptible Transportation Service Agreement dated November 30, 1990, by and between Florida Gas Transmission Company and Chesapeake Utilities Corporation, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1990, File No. 0-593.

Exhibit 10(i) Executive Employment Agreement dated March 26, 1997, by and between Chesapeake Utilities Corporation and each Ralph J. Adkins and John R. Schimkaitis is incorporated herein by reference to Exhibit 10 to the Company's Quarterly Report on Form 10-Q for the period ended June 30, 1997, File No. 001-11590.

Exhibit 10(j) Form of Performance Share Agreement dated January 1, 1998, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Ralph J. Adkins and John R. Schimkaitis is incorporated herein by reference to Exhibit 10 of the Company's Annual Report on Form 10-K for the year ended December 31, 1997, File No. 001-11590.

Exhibit 10(k) Chesapeake Utilities Corporation Cash Bonus Incentive Plan dated January 1, 1992, is incorporated herein by reference to Exhibit 10 to the Company's Annual Report on Form 10-K for the year ended December 31, 1991, File No. 0-593.

Exhibit 10(l) Chesapeake Utilities Corporation Performance Incentive Plan dated January 1, 1992, is incorporated herein by reference to the Company's Proxy Statement dated April 20, 1992, in connection with the Company's Annual Meeting held on May 19, 1992.

Exhibit 10(m) Form of Stock Option Agreement dated January 1, 1998, pursuant to Chesapeake Utilities Corporation Performance Incentive Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Stephen C. Thompson, William C. Boyles, Philip S. Barefoot, Jeremy D. West, William P. Schneider and James R. Schneider, is incorporated herein by reference to Exhibit 10 of the Company's Annual Report on Form 10-K for the year ended December 31, 1997, File No. 001-11590.

Exhibit 12 Computation of Ratio of Earning to Fixed Charges,
filed herewith.

Exhibit 21 Subsidiaries of the Registrant, filed herewith.

Exhibit 23 Consent of Independent Accountants, filed
herewith.

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/ JOHN R. SCHIMKAITIS

 John R. Schimkaitis
 President and Chief Executive
Officer
 Date: March 16, 1999

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ RALPH J. ADKINS

Ralph J. Adkins, Chairman of the Board
and Director
Director
Date: March 16, 1999

/s/ JOHN R. SCHIMKAITIS

John R. Schimkaitis, President,
Chief Executive Officer and
Date: March 16, 1999

/s/ MICHAEL P. MCMASTERS

Michael P. McMasters, Vice President,
Chief Financial Officer and Treasurer
(Principal Financial Officer)
Date: March 16, 1999

/s/ RICHARD BERNSTEIN

Richard Bernstein, Director
Date: March 16, 1999

/s/ WALTER J. COLEMAN

Walter J. Coleman, Director
Date: March 16, 1999

/s/ John W. JARDINE, JR.

John W. Jardine, Jr., Director
Date: March 16, 1999

/s/ RUDOLPH M. PEINS, JR.

Rudolph M. Peins, Jr., Director
Date: March 16, 1999

/s/ ROBERT F. RIDER

Robert F. Rider, Director
Date: March 16, 1999

/s/ JEREMIAH P. SHEA

Jeremiah P. Shea, Director
Date: March 16, 1999

William G. Warden, III, Director
Date: March 16, 1999

Chesapeake Utilities Corporation and Subsidiaries
 Schedule II
 Valuation and Qualifying Accounts

For the Year Ended December 31,	Balance at Beginning of Year	Additions			Balance at End of Year
		Charged to Income	Other Accounts(1)	Deductions(2)	
Reserve Deducted From Related Assets					
Reserve for Uncollectible Accounts					
1998	\$ 331,775	\$280,391	\$ 57,759	\$ (367,412)	\$ 302,513
1997	\$ 392,412	\$203,624	\$ 68,038	\$ (332,299)	\$ 331,775
1996	\$ 309,955	\$364,622	\$ 55,631	\$ (337,796)	\$ 392,412

- (1) Recoveries.
 (2) Uncollectible accounts charged off.

Chesapeake Utilities Corporation and Subsidiaries
 Exhibit 12
 Ratio of Earnings to Fixed Charges

For the Years Ended December 31,	1998	1997	1996
Income from continuing operations	\$ 5,302,586	\$ 5,867,612	\$ 7,781,933
Add:			
Income taxes	3,225,744	3,704,196	4,086,616
Portion of rents representative of interest	130,717	167,029	155,916
Interest on indebtedness	3,256,415	3,224,606	2,884,858
Amortization of debt discount and expense	123,335	119,401	120,345
Earnings as adjusted	\$12,038,797	\$13,082,844	\$15,029,668
Fixed Charges			
Portion of rents representative of interest	\$ 130,717	\$ 167,029	\$ 155,916
Interest on indebtedness	3,256,415	3,224,606	2,884,858
Amortization of debt discount and expense	123,335	119,401	120,345
Fixed Charges	\$ 3,510,467	\$ 3,511,036	\$ 3,161,119
Ratio of Earnings to Fixed Charges	3.43	3.73	4.75

CHESAPEAKE UTILITIES CORPORATION
EXHIBIT 21
SUBSIDIARIES OF THE REGISTRANT

Subsidiaries

State Incorporated

Eastern Shore Natural Gas Company
Sharp Energy, Inc.
Chesapeake Service Company
United Systems, Inc.
Tri-County Gas Company, Inc.
Eastern Shore Real Estate
Xeron, Inc.
Sam Shannaham Well Co.
Sharp Water, Inc.

Delaware
Delaware
Delaware
Georgia
Maryland
Maryland
Texas
Maryland
Delaware

Subsidiary of Eastern Shore Natural Gas Company
Incorporated

State

Dover Exploration Company

Delaware

Subsidiaries of Sharp Energy, Inc.

State Incorporated

Sharpgas, Inc.
Sharpoil, Inc.

Delaware
Delaware

Subsidiaries of Chesapeake Service Company

State Incorporated

Skipjack, Inc.
Capital Data Systems, Inc.
Currin and Associates, Inc.
Chesapeake Investment Company

Delaware
North Carolina
North Carolina
Delaware

CONSENT OF INDEPENDENT ACCOUNTANTS

We consent to the incorporation by reference in the Prospectuses of Chesapeake Utilities Corporation on Form S-2 (File No. 33-26582), Form S-3 (File Nos. 33-28391, 33-64671, 333-37165, 333-64757 and 333-63381) and Form S-8 (File No. 33-301175) of our report dated February 12, 1998 on our audits of the consolidated financial statements and the consolidated financial statement schedules of Chesapeake Utilities Corporation as of December 31, 1998 and 1997 and for each of the three years in the period ended December 31, 1998 included in this Annual Report on Form 10-K.

PricewaterhouseCoopers LLP
Washington, D.C.
March 25, 1999

ARTICLE UT

This schedule contains summary financial information extracted from the Balance Sheets, Income Statements and Statements of Cash Flows for the fiscal year 1998 and is qualified in its entirety by reference to such financial statements.

RESTATED:

PERIOD TYPE	3 MOS	6 MOS	9 MOS	12 MOS
FISCAL YEAR END	DEC 31 1998	DEC 31 1998	DEC 31 1998	DEC 31 1998
PERIOD END	MAR 31 1998	JUN 30 1998	SEP 30 1998	DEC 31 1998
BOOK VALUE	PER BOOK	PER BOOK	PER BOOK	PER BOOK
TOTAL NET UTILITY PLANT	78105923	79207740	80165270	81626158
OTHER PROPERTY AND INVEST	25021432	25319525	25694382	26804812
TOTAL CURRENT ASSETS	26432358	21511067	20977538	26620666
TOTAL DEFERRED CHARGES	11164550	11575896	11716399	10181977
OTHER ASSETS	0	0	0	0
TOTAL ASSETS	140728263	137614228	139053589	145233613
COMMON	2455068	2462270	2470819	2479019
CAPITAL SURPLUS PAID IN	23342529	23601702	23903562	24192188
RETAINED EARNINGS	31397823	31709187	27908713	28892384
TOTAL COMMON STOCKHOLDERS EQ	57515755	58322151	54878856	56355894
PREFERRED MANDATORY	0	0	0	0
PREFERRED	0	0	0	0
LONG TERM DEBT NET	38152000	37892000	37870000	37597000
SHORT TERM NOTES	0	2100000	5200000	11600000
LONG TERM NOTES PAYABLE	0	0	0	0
COMMERCIAL PAPER OBLIGATIONS	0	0	0	0
LONG TERM DEBT CURRENT PORT	520000	520000	520000	520000
PREFERRED STOCK CURRENT	0	0	0	0
CAPITAL LEASE OBLIGATIONS	0	0	0	0
LEASES CURRENT	0	0	0	0
OTHER ITEMS CAPITAL AND LIAB	44540508	38780077	40584733	39160719
TOT CAPITALIZATION AND LIAB	140728263	137614228	139053589	145233613
GROSS OPERATING REVENUE	60169102	103764046	139995969	183568795
INCOME TAX EXPENSE	2426791	2529298	1757692	3181599
OTHER OPERATING EXPENSES	9132650	18353227	27731584	35926301
TOTAL OPERATING EXPENSES	11559441	20882525	29489276	39107900
OPERATING INCOME LOSS	4744218	5706320	5246355	8441082
OTHER INCOME NET	110390	199577	222629	241254
INCOME BEFORE INTEREST EXPEN	4854608	5905897	5468984	8682336
TOTAL INTEREST EXPENSE	854007	1641544	2471129	3379750
NET INCOME	4000602	4264353	2997854	5302586
PREFERRED STOCK DIVIDENDS	0	0	0	0
EARNINGS AVAILABLEFOR COMM	4000602	4264353	2997854	5302586
COMMON STOCK DIVIDENDS	1135924	2400768	3669900	4943347
TOTAL INTEREST ON BONDS	745684	1487015	2226800	2966043
CASH FLOW OPERATIONS	13196414	10634780	10045773	11027405
EPS PRIMARY	.80	.85	.59	1.05
EPS DILUTED	.77	.83	.59	1.04

ARTICLE UT

This schedule contains summary financial information extracted from the Balance Sheets, Income Statements and Statements of Cash Flows for the fiscal year 1997 and is qualified in its entirety by reference to such financial statements.

RESTATED:

PERIOD TYPE	3 MOS	6 MOS	9 MOS	12 MOS
FISCAL YEAR END	DEC 31 1997	DEC 31 1997	DEC 31 1997	DEC 31 1997
PERIOD END	MAR 31 1997	JUN 30 1997	SEP 30 1997	DEC 31 1997
BOOK VALUE	PER BOOK	PER BOOK	PER BOOK	PER BOOK
TOTAL NET UTILITY PLANT	75314310	76180847	76766578	77787816
OTHER PROPERTY AND INVEST	23225413	23286176	24062505	24812830
TOTAL CURRENT ASSETS	27138881	22202081	25254288	31827107
TOTAL DEFERRED CHARGES	12738268	11944514	12841914	11291070
OTHER ASSETS	0	0	0	0
TOTAL ASSETS	138416872	133613619	138925285	145718823
COMMON	2410397	2417414	2424364	2435142
CAPITAL SURPLUS PAID IN	21723848	21959895	22195138	22581463
RETAINED EARNINGS	29388364	28998887	27149356	28533145
TOTAL COMMON STOCKHOLDERS EQ	53232486	53129331	51599071	53655736
PREFERRED MANDATORY	0	0	0	0
PREFERRED	0	0	0	0
LONG TERM DEBT NET	28907000	38647000	28642000	38226000
SHORT TERM NOTES	12000010	9900010	18400010	7600000
LONG TERM NOTES PAYABLE	0	0	0	0
COMMERCIAL PAPER OBLIGATIONS	0	0	0	0
LONG TERM DEBT CURRENT PORT	1257057	1177485	1107545	1051241
PREFERRED STOCK CURRENT	0	0	0	0
CAPITAL LEASE OBLIGATIONS	0	0	0	0
LEASES CURRENT	0	0	0	0
OTHER ITEMS CAPITAL AND LIAB	38217405	38406731	37142185	45185846
TOT CAPITALIZATION AND LIAB	138416872	133613619	138925285	145718823
GROSS OPERATING REVENUE	76302285	121221105	162901824	222489264
INCOME TAX EXPENSE	2253635	2687549	2132434	3427308
OTHER OPERATING EXPENSES	9057058	17733587	26368156	35204402
TOTAL OPERATING EXPENSES	11310693	20421136	28500590	38631702
OPERATING INCOME LOSS	4148755	5541422	5534397	8666464
OTHER INCOME NET	94682	199593	270086	545155
INCOME BEFORE INTEREST EXPEN	4243437	5741015	5804483	9211619
TOTAL INTEREST EXPENSE	809790	1600068	2426318	3344007
NET INCOME	3433648	4140948	3378165	5867612
PREFERRED STOCK DIVIDENDS	0	0	0	0
EARNINGS AVAILABLEFOR COMM	3433648	4140948	3378165	5867612
COMMON STOCK DIVIDENDS	1079781	2163059	3249798	4341964
TOTAL INTEREST ON BONDS	596357	1190742	1960747	2387641
CASH FLOW OPERATIONS	7531133	11315440	6177387	11674801
EPS PRIMARY	.69	.84	.68	1.18
EPS DILUTED	.67	.82	.68	1.17

End of Filing